

ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Utility Air Regulatory Group and American Public Power Association,

Petitioners,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1370

**Alabama Power Company, Georgia Power Company,
Gulf Power Company, Mississippi Power Company,**

Petitioners,

V.

U.S. Environmental Protection Agency, et al.,

Respondents.

No. 15-1371

**CO₂ Task Force of the Florida Electric Power
Coordinating Group, Inc.,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1372

**International Brotherhood of Boilermakers, Iron Ship
Builders, Blacksmiths, Forgers, and Helpers,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1365

**Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1373

National Rural Electric Cooperative Association;
Arizona Electric Power Cooperative, Inc.; Associated
Electric Cooperative, Inc.; Big Rivers Electric
Corporation; Brazos Electric Power Cooperative, Inc.;
Buckeye Power, Inc.; Central Montana Electric Power
Cooperative; Central Power Electric Cooperative, Inc.;
Corn Belt Power Cooperative; Dairyland Power
Cooperative; Deseret Generation & Transmission Co-
operative; East Kentucky Power Cooperative, Inc.; East
River Electric Power Cooperative, Inc.; East Texas
Electric Cooperative, Inc.; Georgia Transmission
Corporation; Golden Spread Electrical Cooperative,
Inc.; Hoosier Energy Rural Electric Cooperative, Inc.;
Kansas Electric Power Cooperative, Inc.; Minnkota
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No. 15-1376

Petitioners,

v.

U.S. Environmental Protection Agency,

Respondent.

**NorthWestern Corporation
d/b/a NorthWestern Energy,**

Petitioner,

V.

U.S. Environmental Protection Agency, et al.,

Respondents.

No. 15-1378

**Tri-State Generation and Transmission Association,
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Petitioner,

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U.S. Environmental Protection Agency,

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No. 15-1374

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GLOSSARY

CAA	Clean Air Act
CO ₂	carbon dioxide
EGU	electric generating unit
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	gigawatts
MATS	Mercury and Air Toxics Standards
RIA	Regulatory Impact Analysis
Rule	Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,662 (Oct. 23, 2015)

INTRODUCTION

Utility and Allied Petitioners request that this Court stay the U.S.

Environmental Protection Agency's ("EPA") final Rule setting limits for carbon dioxide ("CO₂") emissions from existing fossil fuel-fired power plants.¹ In the Rule, EPA asserts that a mere five words in a rarely used provision of the Clean Air Act ("CAA")—"best system of emission reduction"—give it unprecedented authority to require States to restructure the nation's energy industry by reducing the electricity generated by certain types of facilities (primarily coal-fired power plants) and by shifting that generation to EPA-favored facilities (e.g., wind and solar facilities) that emit less CO₂. This shift will substantially increase costs to the public and jeopardize the reliability of the nation's electricity system.

EPA claims to find authority for this extraordinary Rule in Section 111(d) of the CAA, which authorizes the *States* to establish "performance" standards for existing sources in a category (such as fossil fuel-fired electric generating units ("EGUs")), and requires those standards to be "achievable" through "adequately demonstrated" emission-reducing technological upgrades (e.g., scrubbers) or operational processes (e.g., switching from high-sulfur coal to low-sulfur coal) at each such source. *See* 42 U.S.C. § 7411(a)(1), (d). That is what the statute says and that is

¹ Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule ("Rule"), 80 Fed. Reg. 64,662 (Oct. 23, 2015), Att. A. In August 2015, several petitioners requested that EPA stay the Rule. *See, e.g.*, Administrative Stay Petition of the Utility Air Regulatory Group (Aug. 24, 2015), Docket ID No. EPA-HQ-OAR-2013-0602-35728. EPA has not granted a stay.

how EPA has consistently interpreted it for decades. Now EPA purports to find in Section 111(d) *new* authority to force CO₂-emitting EGUs to curtail their “performance” or to shutter entirely in order to accomplish EPA’s mandated emission reductions of up to 48 percent, depending on the State.² This is because no single unit in the source category can achieve EPA’s standards while continuing to perform, even through the use of technological controls or operational processes. To avoid electricity shortages, that lost capacity must be made up by lower- or zero-emission facilities that EPA prefers. EPA conservatively forecasts the Rule will force nearly 11 gigawatts (“GW”) of coal-fired EGUs to shutter *in 2016 alone*,³ the amount needed to keep the lights on in more than two-and-a-half million homes. *See, e.g.,* Pemberton Decl. ¶ 13, Att. B. EPA, however, cannot show that Congress intended to allow *any* federal agency—much less one not even tasked with setting energy policy—to so radically restructure the nation’s electricity system, bypassing all federal and state energy laws and the regulators that have overseen the industry for over seventy years.

EPA concedes that the Rule was born out of frustration with congressional

² Heidell & Repsher Decl. (Exhibit, PA Consulting Group, Inc., “A Survey of Near-Term Damages Associated with the EPA’s Clean Power Plan,” at 3 (Oct. 16, 2015)), Att. C.

³ *See* Energy Ventures Analysis, Inc., “Evaluation of the Immediate Impact of the Clean Power Plan Rule on the Coal Industry,” at 15 (Oct. 2015), *available at* <http://www.nma.org/pdf/EVA-Report-Final.pdf> (“EVA Report”).

inaction.⁴ Our constitutional structure, however, as well as settled principles of administrative law, requires an agency to have clear statutory authority from Congress before it adopts a sweeping regulation imposing billions in costs. As the Supreme Court has explained, “no matter how ‘important, conspicuous, and controversial’ the issue, ... an administrative agency’s power to regulate ... must always be grounded in a valid grant of authority from Congress.” *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 161 (2000) (internal citation omitted). No such authority exists here. Petitioners are likely to succeed on the merits for these and other compelling reasons.⁵

The Supreme Court’s recent decision in *Michigan v. EPA*, 135 S. Ct. 2699 (2015), overturning EPA’s Mercury and Air Toxics Standards (“MATS”), 77 Fed. Reg. 9304 (Feb. 16, 2012), shows why a stay is needed here. Just days before *Michigan* was decided, EPA Administrator Gina McCarthy boasted that, as a simple result of the time required to litigate the MATS rule, “[m]ost of [the regulated EGUs] are already in compliance, [and] investments have been made.”⁶ Thus, she said, “we’re still going to get at the toxic pollution from these facilities” no matter how the Supreme Court

⁴ Valerie Richardson, *On climate change, Obama, EPA plan action without Congress*, WASHINGTON TIMES, Aug. 14, 2013, <http://www.washingtontimes.com/news/2013/aug/14/climate-change-obama-epa-plan-action-sans-congress/>.

⁵ For example, because EGUs are already regulated under Section 112 of the CAA, 42 U.S.C. § 7412, they are not subject to regulation under Section 111(d).

⁶ Timothy Cama & Lydia Wheeler, *Supreme Court overturns landmark EPA air pollution rule*, THE HILL, June 29, 2015, available at <http://thehill.com/policy/energy-environment/246423-supreme-court-overturns-epa-air-pollution-rule>. See also Patton Decl. ¶ 15, Att. D.

ruled.⁷ By setting this Rule’s first binding deadline for September 6, 2016 (when the Rule will still be under judicial review), and openly pressing that 2016 be “a year of implementation,”⁸ EPA again attempts to lock in regulatory outcomes before a court can determine the regulation’s validity, and to thwart this Court’s ability to grant meaningful relief.

Utility and Allied Petitioners will suffer immediate and irreparable harm absent a stay because planning, permitting, and constructing new generation takes years, and thus must begin now to meet the Rule’s compliance obligations in 2022. The public interest also decisively favors a stay, as the Rule will cause substantial electricity rate increases and jeopardize reliability, while doing little to reduce global greenhouse gas emissions. This Court should stay the Rule while it considers the petitions for review.

BACKGROUND

I. Statutory and Regulatory Background

Section 111 governs performance standards for “stationary sources” of air pollution. 42 U.S.C. § 7411. Under Section 111(b), EPA establishes nationally applicable “standards of performance” to control emissions from “*new* sources.” *Id.* § 7411(b) (emphasis added). Under Section 111(d), the *States* develop source-specific “standards of performance for ... *existing* source[s].” *Id.* § 7411(d)(1) (emphasis

⁷ *Id.*

⁸ William Mauldin & Colleen McCain Nelson, *U.S., China Build on Plan to Cut Emissions*, WALL ST. J., Sept. 15, 2015, *available at* <http://www.wsj.com/articles/u-s-china-build-on-climate-accord-1442342194> (subscription required).

added). In both cases, the standards must be “*achievable* through application of the *best system of emission reduction* ... [that] the Administrator determines has been *adequately demonstrated*.” *Id.* § 7411(a)(1) (emphases added). EPA purports to find its vast authority to restructure the nation’s electric industry in the five-word phrase, “best system of emission reduction.”

Unlike new sources, which can incorporate state-of-the-art control systems and operational processes into their design and construction, *existing* sources must be retrofitted to achieve emissions reductions. For some sources, retrofitting might be either physically impossible or economically prohibitive. Congress thus limited the circumstances in which performance standards could be established for existing sources. For example, existing sources that are regulated under Section 112 of the CAA are not subject to performance standards under Section 111(d). *Id.* § 7411(d)(1). Moreover, in establishing and determining the applicability of standards and compliance schedules, EPA and the States must “take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.” *Id.* In other words, existing source standards may be less stringent than new source standards, and they may be excused altogether for a specific source based on factors such as the source’s remaining useful life.

II. EPA’s 111(d) Rule for Existing EGUs

EPA concedes that no pollution control measure or process can be installed at any existing EGU to achieve the Rule’s emission rates. 80 Fed. Reg. at 64,728

("[M]ost of the CO₂ controls need to come in the form of those other measures ... that involve, in one form or another, replacement of higher emitting generation with lower- or zero-emitting generation."). Rather, the Rule establishes CO₂ performance rates that can be achieved, if at all, only by measures applied across the electric grid, including shifting generation from fossil fuel-fired EGUs to those with low or no CO₂ emissions. The Rule thus establishes a "system of emission reduction" for the "grid," not for individual EGUs as required by the statute.

The Rule essentially dictates the market share of each generation fuel-type, shifting generation from EPA-disfavored sources (such as coal-fired EGUs) to those it prefers (such as wind and solar). EPA accomplishes this through what it calls "Building Blocks." The first Building Block assumes increased efficiency targets for coal-fired EGUs, because using less coal to generate the same amount of electricity will result in fewer CO₂ emissions. The second Building Block assumes increased utilization of natural gas combined cycle units—forcing CO₂ emission reductions by shifting generation from coal-fired EGUs to lower-emitting natural gas-fired EGUs. The third Building Block forces CO₂ emission reductions by displacing higher-emitting generation with zero-emission generation from renewable energy sources.

EPA uses these shifts in generation to set CO₂ performance standards for individual existing fossil-fuel fired power plants—standards that not only are unachievable by any existing EGU with emission control processes but that are significantly more stringent than EPA's simultaneously announced standards for *new*

power plants under Section 111(b). *See* 80 Fed Reg. 64,510 (Oct. 23, 2015) (new source rule). From this, EPA also establishes state-by-state CO₂ emissions targets. EPA claims that the Rule and its standards are “flexible” because States are “not required” to use the Building Blocks—but no State can meet its CO₂ target *except* by reducing generation from CO₂-emitting units and, if it wants to make up for the lost capacity, by shifting generation to other types of resources. 80 Fed. Reg. at 64,663, 64,728, 64,734.

State plans implementing the Rule, or requests for extension, must be submitted to EPA by September 6, 2016, almost certainly while the Rule is still under review by this Court. 40 C.F.R. § 60.5760(a). Final plans must demonstrate that the State will meet interim emission targets beginning in 2022, and final targets by 2031. *Id.* § 60.5745(a)(2)(i), (a)(5)(ii), (a)(6)(iii). Extension requests are not mere formalities; they must show not only substantial “progress” toward a final plan but also “meaningful” public participation, requiring that state plan development begin *now* (and that plans be established or well underway by September 2016), regardless of whether the State submits a final plan or an extension request. *Id.* § 60.5765(a)(1), (3). If a State does not submit an approvable plan or extension request by September 2016 (or if EPA determines the State’s plan or extension request is not “justified,” 80 Fed. Reg. at 64,675), EPA will impose a federal plan. 40 C.F.R. § 60.5840(b).

Preparing final plans or extension requests will require many States to immediately start the legislative and regulatory process to rewrite utility laws and

regulations, and to abandon their historical practice of protecting consumers by requiring the lowest cost generators to be utilized first. The Rule drives a shift away from this traditional “least-cost dispatch” electricity planning to a centrally planned model that prioritizes electricity generation based on CO₂ emissions rather than on cost and reliability. The legislative and regulatory changes that States must undertake to implement this shift require Utility Petitioners immediately to both plan for and undertake costly measures to comply with the Rule. Indeed, this shift will require an historic transformation in the way Utility Petitioners operate their businesses. *See, e.g.*, Greene Decl. ¶¶ 10, 13-14, Att. E; Voyles Decl. ¶ 5, Att. F.

ARGUMENT

This Court considers four factors in issuing a stay: (1) the likelihood movants will prevail on the merits; (2) the likelihood of irreparable harm to movants in the absence of a stay; (3) the possibility of substantial harm to others if a stay is granted; and (4) the public interest. *Wash. Metro. Area Transit Comm’n v. Holiday Tours, Inc.*, 559 F.2d 841, 842-43 (D.C. Cir. 1977); D.C. Cir. R. 18(a). All four factors favor a stay.

I. Utility and Allied Petitioners Are Likely To Prevail on the Merits.

A. EPA Exceeded Its Authority Under Section 111(d).

1. Petitioners will prevail on the merits because EPA exceeded its authority under Section 111(d). Section 111 authorizes performance standards for new and existing sources that are “achievable through the application of the best system of emission reduction” that is “adequately demonstrated” for that source. 42 U.S.C. §

7411(a)(1). In other words, Section 111 requires sources of air pollution to install new technology, like scrubbers, or to employ operational processes, like burning cleaner coal, to reduce air pollution. In every performance standard adopted over the past forty-five years, EPA has applied a “best system of emission reduction” that achieves a lower emission rate through technologies or operational processes applied *at the individual source*. See, e.g., 40 Fed. Reg. 53,340, 53,342 (Nov. 17, 1975) (“the technology-based approach of ... section [111] ... extend[s] ... to action under section 111(d).”). That is how every technology-based environmental program works.⁹ But that is not how *this* Rule works.

Ignoring the Supreme Court’s instruction that statutory terms “must be read in their context and with a view to their place in the overall statutory scheme,” EPA in the Rule has abandoned the well-established and contextually compelled meaning of “best system of emission reduction.” *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2441 (2014) (internal quotation marks and citation omitted) (“*UARG*”). Instead, EPA focuses on the word “system” in isolation, finds a dictionary that defines it as any “set of things,” and then re-defines “system of emission reduction” as any “set of

⁹ Federal environmental law includes two types of programs: (i) those requiring facilities to install pollution controls or to adopt operating processes that reduce the *rate* at which pollutants are released during production, see, e.g., 33 U.S.C. §§ 1311(b) (effluent limitations), 1314(b) (same); 42 U.S.C. §§ 7411 (source performance standards), 7475(a)(4) (best available control technology), and (ii) those authorizing limits on *levels* of pollution, see, e.g., 33 U.S.C. § 1312 (water quality standards); 42 U.S.C. §§ 7651, *et seq.* (acid rain program), 7409 (national ambient air quality standards). Section 111 is a classic example of an emission *rate* program.

measures [undertaken anywhere] that work together to reduce emissions.” 80 Fed. Reg. at 64,720. According to EPA, these “measures” allow EPA to fundamentally restructure the way the nation’s electricity is generated, by requiring *reduced generation* (rather than improved emission performance) from existing EGUs that emit CO₂. What EPA has promulgated, then, is not a standard of performance, but a standard of *nonperformance* under which there is no limit on EPA’s authority to govern and transform the country’s electric sector, and to do so at a cost—by EPA’s own admission—of billions of dollars per year.¹⁰

But Congress has never given EPA the authority—under Section 111(d)¹¹ or otherwise—to mandate that coal-fired power plants be closed or curtailed and replaced with other forms of generation or to otherwise impose generic constraints on their generation. *See, e.g.*, S. Con. Res. 8, S. Amdt. 646, 113th Cong. (2013) (rejecting carbon tax); Climate Prot. Act of 2013, S. 332, 113th Cong. (2013) (rejecting fees on greenhouse gas emissions); Clean Energy Jobs & Am. Power Act, S. 1733, 111th Cong. (2009) (rejecting greenhouse gas cap-and-trade program); *compare* The Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C. §§ 8301 *et seq.* (prohibiting new oil- and gas-fired generation in favor of coal-fired generation). “When an agency

¹⁰ EPA, Regulatory Impact Analysis for the Clean Power Plan Final Rule at 3-22 to 3-23, 3-25 to 3-27, 3-30 (Aug. 2015) (“RIA”), *available at* <http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-regulatory-impact-analysis>.

¹¹ The author of Section 111(d) recently described that provision as a “tiny little gap.” Elizabeth Harball, *111(d) author says Clean Air Act ‘not the best way’ to curb emissions*, CLIMATEWIRE, Oct. 16, 2015, *available at* <http://www.eenews.net/climatewire/2015/10/16/stories/1060026413> (subscription required).

claims to discover in a long-extant statute an unheralded power to regulate a significant portion of the American economy,” courts “typically greet its announcement with a measure of skepticism.” *UARG*, 134 S. Ct. at 2444 (internal quotation marks and citation omitted). Here, the text, context, and historical understanding of Section 111 defeat this “enormous and transformative expansion in EPA’s regulatory authority.” *Id.*

2. Petitioners will also prevail because the Rule establishes performance standards that are not “achievable” through application of any control technology or operating process that is “adequately demonstrated” for use *at any individual EGU*. 42 U.S.C. § 7411(a)(1). Section 111 applies to “stationary sources” of air pollution, which Congress has defined as “any building, structure, facility, or installation which emits or may emit any air pollutant.” *Id.* § 7411(a)(3). Rather than basing the Rule on “pollution control systems that will limit emissions to the level ‘achievable through ... adequately demonstrated’” techniques at individual facilities, as the statute requires, *see ASARCO, Inc. v. EPA*, 578 F.2d 319, 327 (D.C. Cir. 1978) (internal citation omitted), EPA redefines “source” to “include[] the ‘owner or operator’ of any building ... for which a standard of performance is applicable” and to exclude only those “actions beyond the ability of the [source’s] owners/operators to control.” 80 Fed. Reg. at 64,762 & n.472. On this basis, EPA concludes, Section 111(d) performance standards may reflect “overall emission reductions” from *combinations* of sources (including sources, such as renewables, that are outside the source category). *Id.* at 64,762,

64,779, 64,911. This reading of “source” eviscerates the limits Congress placed on *what* is regulated under Section 111(d). As in *ASARCO*, other facilities at a plant site—or spread over the electric grid—cannot be used to define another facility’s on-site performance standard obligation. Yet, that is precisely what the Rule does, requiring a plant owner/operator to shift generation to other types of plants.

Section 111(d) also requires that the performance standard be based on a system that is “adequately demonstrated.” 42 U.S.C. § 7411(a)(1). An “adequately demonstrated” system is one that applies to the “source,” considering the “cost” of that system, its “health and environmental impact,” and “energy requirements” that result from using the “system” of “reduction” at the source. *Id.* § 7411(a)(1), (d)(1); 40 C.F.R. § 60.22(b)(5). There is no demonstrated pollution control equipment or process that can be installed at any existing EGU (or even a new one) that could achieve the Rule’s performance rates. *See, e.g.*, Brummett Decl. ¶ 16, Att. G; Ledger Decl. ¶ 10, Att. H; McLennan Decl. ¶ 11, Att. I; Rasmussen Decl. ¶ 3, Att. J; K. Johnson Decl. ¶ 27, Att. K.

3. Petitioners are also likely to prevail because the Rule imposes standards on *existing* EGUs that are more stringent than any of EPA’s *new* source standards.¹²

¹² The standard for new coal-fired EGUs, for instance, is 1,400 lbs. CO₂/MWh, 95 lbs. *higher* than the 1,305 lb. standard EPA has set for existing coal-fired EGUs. 40 C.F.R. pt. 60, sbpt. TTTT, Tbl. 1; *Id.* sbpt. UUUU, Tbl. 1. The standard for a large reconstructed coal-fired EGU (an EGU that undergoes such significant work that it is then considered to be “new” for purposes of Section 111) is 495 lbs. higher than the

Even the newest EGUs utilizing the technologies specified in the new source performance standards cannot achieve the Rule's emission rates; hence the reallocation of market share based on fuel type embedded in the Rule. This is not a Section 111 performance standard, and it stands the statute (and Congress's intent in crafting a separate and more lenient subsection for existing sources) on its head.

Where an agency claims for itself the authority to resolve “question[s] of deep economic and political significance,” courts carefully examine whether Congress has “expressly” “assign[ed]” the agency the power to resolve those issues. *King v. Burwell*, 135 S. Ct. 2480, 2489 (2015) (internal quotation marks omitted). The Rule's restructuring of the electric sector is not only wholly untethered from the CAA, but is an assertion of authority over energy policy that is greater than what Congress has given to *any* federal agency, including the Federal Energy Regulatory Commission (“FERC”). By dictating market share for different types of electric generators, the nation's historic energy regulators—FERC and the States—are relegated to the sidelines while EPA becomes the nation's new energy czar.

B. EPA's Rule Is Unlawful for Other Reasons.

The Rule is also unlawful in other ways. As a threshold matter, Section 111(d) prohibits EPA from regulating EGUs because those sources are already regulated under Section 112. 42 U.S.C. § 7411(d)(1). The Rule also addresses matters that

standard for existing coal-fired EGUs and 400 lbs. higher than the standard for new sources. *Id.* sbpt. TTTT, Tbl. 1.

Congress has preserved as the exclusive province of state public utility commissions, *see Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-06 (1983), and is *per se* coercive, unconstitutional, and a direct violation of the Tenth Amendment. *See New York v. United States*, 505 U.S. 144, 188 (1992). These and other reasons for the Rule's invalidity will be developed during merits briefing.

II. Petitioners Will Suffer Imminent and Irreparable Injury Absent a Stay.

The Supreme Court's recent decision holding that EPA acted "unreasonably" when it promulgated MATS came too late for the utility industry. *Michigan*, 135 S. Ct. at 2712. There were no stay proceedings in that case, and thus utilities spent billions of dollars, permanently retired power plants, and committed to irreversible action before the Supreme Court invalidated the rule. *See, e.g.,* McInnes Decl. ¶ 22, Att. L; Patton Decl. ¶ 16. Absent a stay of this Rule, the same will happen here.

A. The Rule Requires Immediate Action by Petitioners.

While the Rule provides that the deadline for final state plans can nominally be extended to 2018, in reality, EPA requires States and Utility Petitioners to undertake significant action in *less than one year*. Indeed, Petitioners must begin taking steps *now* if they are to have resources online in 2022 to replace curtailed or retired generation. *See, e.g.,* Greene Decl. ¶¶ 30, 32-33; Patton Decl. ¶ 24.

To submit a plan or to secure an extension of the plan due date, each State must—before September 6, 2016—begin to identify the coal-fired EGUs it intends to curtail or close, show how it will increase natural gas plant utilization, assess where

and how renewable generation will be constructed, and evaluate how and where the necessary massive infrastructure will be built. The States cannot do this alone. Much of the burden will fall on Utility Petitioners to identify the least costly candidates for closure, plan for load-shifting from coal to natural gas units while maintaining reliability, and undertake infrastructure planning, siting, and permitting for new generation and transmission facilities. *See* Patton Decl. ¶¶ 20, 22.

Moreover, the electric sector is a long lead-time industry. The 2022 compliance date requires that Utility Petitioners begin *now* to identify and prepare EGUs for retirement, *see, e.g.*, Heidell & Repsher Decl., PA Consulting Report at 8-9, 10-11; McInnes Decl. ¶ 14; and to prepare for corresponding increases in natural gas and renewable generation, *see, e.g.*, Greene Decl. ¶ 6; Heilbron Decl. ¶ 3, Att. M; L. Johnson Decl. ¶ 26, Att. N. Planning, permitting, and constructing new generation to replace those units will take between three and seventeen years. *See, e.g.*, Pemberton Decl. ¶ 7; Burroughs Decl. ¶ 7, Att. O; McLennan Decl. ¶ 20; Campbell Dec. ¶ 22, Att. P; Voyles Decl. ¶ 5. Similarly, transmission projects can take up to ten years, and gas pipeline infrastructure can take up to seven years. *See, e.g.*, McInnes Decl. ¶¶ 13-15; Heidell & Repsher Decl., PA Consulting Report at 10. EPA expressly “recognizes that successfully achieving reductions by 2022 will be facilitated by actions and investments ... prior to 2022” and “encourage[s] early actions.” 80 Fed. Reg. at 64,670. EPA actually estimates that about 70 percent of the final emission reduction target must be achieved *before the mandatory compliance period begins* in 2022. RIA at 3-20,

Tbl. 3-6 (estimating that 68.9 percent and 70.2 percent of the 2030 reductions are achieved in the rate-based and mass-based cases, respectively, in 2020). Utility Petitioners have no choice but to begin the energy planning mandated by the Rule *now*, to fulfill their obligation to provide reliable electricity to customers at just and reasonable rates. *See, e.g.*, McLennan Decl. ¶¶ 21-22, 24; Heilbron Decl. ¶¶ 22-23; *cf.* 16 U.S.C. § 824o; *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1169 (D.C. Cir. 1987).

B. Utility and Allied Petitioners Face Irreparable Harm Now.

For all its complexity, the central feature of the Rule is straightforward: It requires utilities to significantly reduce the use of fossil fuel-fired (and, in particular, coal-fired) EGUs even where such generation is the least-cost, most reliable option. As EPA itself concedes, the Rule will force the retirement of power plants that otherwise have many years of remaining useful life.¹³ *See, e.g.*, EVA Report at 15; Brummett Decl. ¶¶ 16-18; Frenzel Decl. ¶ 24, Att. Q; L. Johnson Decl. ¶¶ 10, 24-25.

For each EGU that must be retired or curtailed, Utility Petitioners must carefully plan and implement changes to the system to replace that lost generation.

See, e.g., Voyles Decl. ¶ 5; Burroughs Decl. ¶ 22; Reaves Decl. ¶ 22, Att. R; L. Johnson

¹³ EPA's modeling projects the Rule will cause a net retirement of around 11 GW of capacity at 53 EGUs in 2016 alone. *See* EVA Report at 15, 63 & Ex. 29. EPA further estimates 15 GW will retire by 2020, and 33 GW will retire by 2030. RIA at 3-31, Tbl. 3-12. EPA says its projections are the "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt," *id.* at 3-11, but EPA's projected impacts are almost certainly unrealistically low. *See* Heidell & Repsher Decl., PA Consulting Report at 11-14; EVA Report at 19-25.

Decl. ¶¶ 25-27, 30; Jura Decl. ¶¶ 25-26, 28, Att. S. Coal-fired EGUs located next to mines will experience uniquely severe impacts due to the mutual dependence of the mine and EGU. Brummett Decl. ¶¶ 30-41. Once the decision to retire an EGU and associated infrastructure has been made, it will be difficult or impossible to undo: as resources are diverted from that unit, extraordinary, irreparable harms to both the utilities and the communities they serve will immediately follow. *See, e.g.*, Pemberton Decl. ¶¶ 15, 23; Greene Decl. ¶ 32; Burroughs Decl. ¶ 22; Reaves Decl. ¶ 22; Jura Decl. ¶ 33. These include:

- **Loss of jobs and harm to communities:** Plant retirements will cause significant job losses, in turn hurting local communities (e.g., falling home prices). *See, e.g.*, Jura Decl. ¶ 32; Reaves Decl. ¶ 2; Heilbron Decl. ¶ 2; Frenzel Decl. ¶ 34; Ledger Decl. ¶ 30.
- **Unrecoverable costs of shutting down a plant:** Decommissioning, dismantling, and otherwise preparing to retire a power plant involves substantial costs that will either be irreparably borne by utilities or passed on to ratepayers. *See, e.g.*, Heidell & Repsher Decl., PA Consulting Report at 10-11; McInnes Decl. ¶¶ 12, 17; Ledger Decl. ¶ 29.

Utility Petitioners' supporting declarations identify numerous additional harms, including contract cancellation costs for units retiring early, *see, e.g.*, Greene Decl. ¶ 34; Burroughs Decl. ¶ 23; Heilbron Decl. ¶ 24; stranded costs from prematurely retired or artificially curtailed units, *see, e.g.*, Pemberton Decl. ¶ 28; Patton Decl. ¶ 28; Frenzel Decl. ¶ 8(d); Rasmussen Decl. ¶¶ 9-11; Campbell Dec. ¶ 21; downgraded credit ratings and resulting higher costs of capital, *see, e.g.*, McLennan Decl. ¶ 23; Jura Decl. ¶¶ 27, 29, 32; operational disruptions, including lost or displaced investments, *see, e.g.*,

Rasmussen Decl. ¶¶ 9-10; Voyles Decl. ¶ 5; costs to maintain resource and transmission adequacy, *see, e.g.*, Heidell & Repsher Decl., PA Consulting Report at 22-24; increases in electricity prices, *see, e.g.*, Brummett Decl. ¶ 28; Campbell Decl. ¶ 24; Ledger Decl. ¶¶ 9, 29; McLennan Decl. ¶¶ 8, 23; Rasmussen Decl. ¶ 9; *see also Monongahela Power Co. v. Schriber*, 322 F. Supp. 2d 902, 922 (S.D. Ohio 2004) (citing *Mich. Bell Tel. Co. v. Engler*, 257 F.3d 587, 599 (6th Cir. 2001)) (explaining that increased rates establish irreparable harm), and impacts to local communities as jobs and tax revenues disappear, *see, e.g.*, Burroughs Decl. ¶¶ 24-25; Reaves Decl. ¶¶ 25-26; L. Johnson Decl. ¶¶ 8-14, 32; Brummett Decl. ¶¶ 43-44.¹⁴

Further, as many Declarants and others explain, the construction, planning, development, coordination, siting, and permitting of energy resources to meet future demand is complex and involves tremendous costs and long lead times, *see, e.g.*, K. Johnson Decl. ¶¶ 13 & n.9, 28; Voyles Decl. ¶ 6; Campbell Decl. ¶ 22; Pemberton Decl. ¶ 7; Reaves Decl. ¶ 7; Heilbron Decl. ¶ 7; Frenzel Decl. ¶¶ 26-27; Rasmussen Decl. ¶ 12; EVA Report at 35-43, and will result in unrecoverable compliance costs including:

- Decisions regarding whether to invest in existing fossil fuel-fired EGUs (including emission-reduction measures) or to retire them. *See, e.g.*, L. Johnson Decl. ¶ 29; Jura Decl. ¶ 30; Ledger Decl. ¶ 34. Capital upgrades generally occur

¹⁴ The unique structure of electric cooperatives will force rural and often economically disadvantaged customers to bear the *entire cost* of stranded investments, new infrastructure, downgraded credit ratings, and other costs of complying with the Rule. *See, e.g.*, K. Johnson Decl. ¶¶ 11, 20, 31 & n.8.

during planned outages every 18-36 months and must be coordinated with other utilities' outages. *See* McInnes Decl. ¶ 19; EVA Report at 43.

- Capital expenditures associated with planning, coordinating, siting, permitting, and constructing new transmission lines, natural gas pipelines and storage, and other infrastructure needed to replace retiring generation and maintain reliability. *See, e.g.,* Frenzel Decl. ¶ 27; Campbell Decl. ¶¶ 2, 3. Such expenditures cannot be recovered absent the approval of the state public utility commission—and even then, would result in rate hikes for customers who cannot themselves recover costs. *See* K. Johnson Decl. ¶ 21.

These impacts constitute irreparable harm because they will have a serious effect on Utility Petitioners' business. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) (Scalia, J., concurring in part and concurring in the judgment) (“[C]omplying with a regulation later held invalid almost *always* produces the irreparable harm of nonrecoverable compliance costs.” (emphasis in original)).

III. The Balance of Harms and the Public Interest Favor a Stay.

The final two factors also favor a stay. There is no possibility of substantial and imminent harm to others if a stay is granted. Utility Petitioners have already significantly reduced CO₂ emissions from 2005 levels and are continuing to reduce such emissions even absent the Rule. EVA Report at 4, Ex. 2. A stay would not impact Utility Petitioners' ongoing voluntary emission reduction activities or those undertaken pursuant to state requirements.

The public interest also favors a stay. The public has a strong interest in reliable, affordable electricity. Granting a stay would ensure the Rule will not affect the cost or reliability of the nation's electricity supply unless the Rule is upheld.

Preserving the status quo would not endanger the public interest in environmental quality. The Rule addresses less than one percent of global human-made greenhouse emissions.¹⁵ EPA does not even claim that the Rule will do anything to halt or mitigate climate change. Thus, the balance of harms and public interest strongly favor a stay. *Cf. In re EPA*, Nos. 15-3799/3822/3853/3887, 2015 WL 5893814, at *3 (6th Cir. Oct. 9, 2015) (staying landmark EPA water rule to “temporarily silence[] the whirlwind of confusion that springs from uncertainty about the requirements of the new Rule and whether they will survive legal testing”).

CONCLUSION

For the foregoing reasons, Utility and Allied Petitioners respectfully request the Court stay the Rule and preserve the status quo pending judicial review.

¹⁵ EPA estimates the Rule will reduce U.S. anthropogenic CO₂ emissions by 413-415 million tons in 2030. RIA at 3-19, Tbl. 3-5. The United Nations Intergovernmental Panel on Climate Change (“IPCC”) calculated that 2010 global anthropogenic greenhouse gas emissions were 49 billion tons. IPCC, Climate Change 2014, Mitigation of Climate Change, at 6 (2014), *available at* http://report.mitigation2014.org/spm/ipcc_wg3_ar5_summary-for-policymakers_approved.pdf. Assuming similar global emissions in 2030, EPA’s estimated emission reductions due to the Rule would equal just 0.85 percent of global anthropogenic emissions.

Dated: October 23, 2015

Respectfully submitted,

A handwritten signature in black ink, appearing to read 'F. William Brownell', written over a horizontal line.

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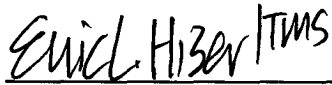
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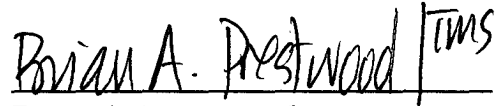
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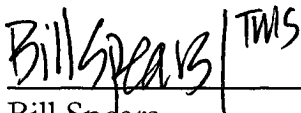
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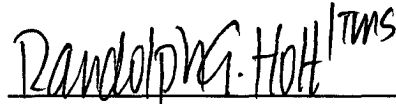
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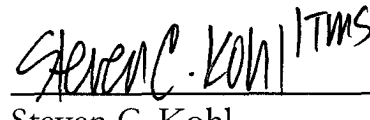
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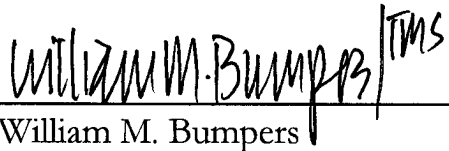
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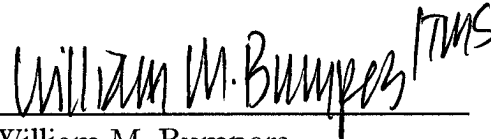
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Counsel for United Mine Workers of America

Dated: October 23, 2015

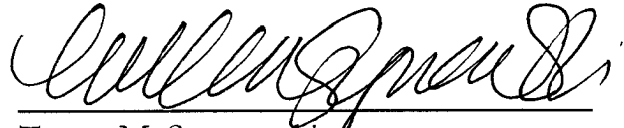
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CERTIFICATE OF COMPLIANCE WITH CIRCUIT RULE 18(a)(2)

I certify that on October 23, 2015, Eric Hostetler, counsel for the Respondents U.S. Environmental Protection Agency, et al., was informed by telephone of the filing of the Motion of Utility and Allied Petitioners for Stay of Rule.



Tauna M. Szymanski

CERTIFICATE OF SERVICE

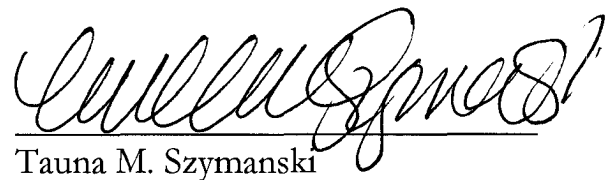
I hereby certify that on this 23rd day of October 2015, one copy of the foregoing Motion of Utility and Allied Petitioners for Stay of Rule was e-mailed to each of the following pursuant to Respondents' agreement to accept service by e-mail upon the named individuals in lieu of hand delivery:

Scott Jordan
U.S. Environmental Protection Agency
jordan.scott@epa.gov

Howard Hoffman
U.S. Environmental Protection Agency
hoffman.howard@epa.gov

Eric Hostetler
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Norman Rave
U.S. Department of Justice
norman.rave@usdoj.gov



Tauna M. Szymanski

ADDENDUM
PURSUANT TO CIRCUIT RULE 18(a)(4)

**UTILITY AND ALLIED PETITIONERS'
CERTIFICATE AS TO PARTIES AND AMICI**

Pursuant to Circuit Rules 18(a)(4), 27(a)(4), and 28(a)(1)(A), Utility and Allied Petitioners state as follows:

A. Parties, Intervenors, and *Amici Curiae*

These cases involve the following parties:

Petitioners:

No. 15-1370: Utility Air Regulatory Group and American Public Power Association.

No. 15-1371: Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company.

No. 15-1372: CO₂ Task Force of the Florida Electric Power Coordinating Group, Inc.

No. 15-1365: International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers, and Helpers.

No. 15-1373: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

No. 15-1376: National Rural Electric Cooperative Association; Arizona Electric Power Cooperative, Inc.; Associated Electric Cooperative, Inc.; Big Rivers Electric Corporation; Brazos Electric Power Cooperative, Inc.; Buckeye Power, Inc.; Central Montana Electric Power Cooperative; Central Power Electric Cooperative,

Inc.; Corn Belt Power Cooperative; Dairyland Power Cooperative; Deseret Generation & Transmission Co-operative; East Kentucky Power Cooperative, Inc.; East River Electric Power Cooperative, Inc.; East Texas Electric Cooperative, Inc.; Georgia Transmission Corporation; Golden Spread Electrical Cooperative, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; Minnkota Power Cooperative, Inc.; North Carolina Electric Membership Corporation; Northeast Texas Electric Cooperative, Inc.; Northwest Iowa Power Cooperative; Oglethorpe Power Corporation; PowerSouth Energy Cooperative; Prairie Power, Inc.; Rushmore Electric Power Cooperative, Inc.; Sam Rayburn G&T Electric Cooperative, Inc.; San Miguel Electric Cooperative, Inc.; Seminole Electric Cooperative, Inc.; South Mississippi Electric Power Association; South Texas Electric Cooperative, Inc.; Southern Illinois Power Cooperative; Sunflower Electric Power Corporation; Tex-La Electric Cooperative of Texas, Inc.; Upper Missouri G. & T. Electric Cooperative, Inc.; Wabash Valley Power Association, Inc.; Western Farmers Electric Cooperative; and Wolverine Power Supply Cooperative, Inc.

No. 15-1378: NorthWestern Corporation d/b/a NorthWesternEnergy.

No. 15-1374: Tri-State Generation and Transmission Association, Inc.

No. 15-1375: United Mine Workers of America.

No. 15-1377: Westar Energy, Inc.

Respondents:

Respondents are the United States Environmental Protection Agency (in Nos. 15-1365, 15-1370, 15-1372, 15-1373, 15-1374, 15-1375, 15-1376), and the United States Environmental Protection Agency and Gina McCarthy, Administrator (in Nos. 15-1371, 15-1377, 15-1378).

Intervenors and Amici Curiae:

There are no intervenors or *amici curiae* in these cases.

ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

**Utility Air Regulatory Group and American Public
Power Association,**

Petitioners,

V.

U.S. Environmental Protection Agency,

Respondent.

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No. 15-1370

**On Petition for Review of an Action of the
United States Environmental Protection Agency**

**ATTACHMENTS TO MOTION OF UTILITY AND
ALLIED PETITIONERS FOR STAY OF RULE**

VOLUME I of II
(Attachment A)

[Additional captions listed on the following pages]

October 23, 2015

Respondents.

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) **No. 15-1371**

Respondent.

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) **No. 15-1372**

Respondent.

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) **No. 15-1365**

**Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1373

National Rural Electric Cooperative Association; Arizona Electric Power Cooperative, Inc.; Associated Electric Cooperative, Inc.; Big Rivers Electric Corporation; Brazos Electric Power Cooperative, Inc.; Buckeye Power, Inc.; Central Montana Electric Power Cooperative; Central Power Electric Cooperative, Inc.; Corn Belt Power Cooperative; Dairyland Power Cooperative; Deseret Generation & Transmission Cooperative; East Kentucky Power Cooperative, Inc.; East River Electric Power Cooperative, Inc.; East Texas Electric Cooperative, Inc.; Georgia Transmission Corporation; Golden Spread Electrical Cooperative, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; Minnkota Power Cooperative, Inc.; North Carolina Electric Membership Corporation; Northeast Texas Electric Cooperative, Inc.; Northwest Iowa Power Cooperative; Oglethorpe Power Corporation; PowerSouth Energy Cooperative; Prairie Power, Inc.; Rushmore Electric Power Cooperative, Inc.; Sam Rayburn G&T Electric Cooperative, Inc.; San Miguel Electric Cooperative, Inc.; Seminole Electric Cooperative, Inc.; South Mississippi Electric Power Association; South Texas Electric Cooperative, Inc.; Southern Illinois Power Cooperative; Sunflower Electric Power Corporation; Tex-La Electric Cooperative of Texas, Inc.; Upper

No. 15-1376

Missouri G. & T. Electric Cooperative, Inc.; Wabash
Valley Power Association, Inc.; Western Farmers
Electric Cooperative; and Wolverine Power Supply
Cooperative, Inc.,

Petitioners,

v.

U.S. Environmental Protection Agency,

Respondent.

NorthWestern Corporation
d/b/a NorthWestern Energy,

Petitioner,

v.

U.S. Environmental Protection Agency, et al.,

Respondents.

Tri-State Generation and Transmission Association,
Inc.,

Petitioner,

v.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1378

No. 15-1374

United Mine Workers of America,

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1375

Westar Energy, Inc.,

Petitioner,

V.

U.S. Environmental Protection Agency, et al.,

Respondents.

No. 15-1377

**ATTACHMENTS TO MOTION OF UTILITY AND
ALLIED PETITIONERS FOR STAY OF RULE**

Tab	Description
A	Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,662 (Oct. 23, 2015)
B	Declaration of John L. Pemberton (Oct. 13, 2015)
C	Declaration of James A. Heidell & Mark Repsher (Oct. 16, 2015) <ul style="list-style-type: none">• PA Consulting Group, Inc., A Survey of Near-Term Damages Associated with the EPA's Clean Power Plan (Oct. 16, 2015)
D	Declaration of Charles R. Patton (undated)
E	Declaration of Kim Greene (Oct. 13, 2015)
F	Declaration of John N. Voyles, Jr. (Oct. 20, 2015)
G	Declaration of Derrick Brummett (Oct. 14, 2015)
H	Declaration of Patrick F. Ledger (Oct. 14, 2015)
I	Declaration of Robert N. McLennan (Oct. 12, 2015)
J	Declaration of Kimball Rasmussen (Oct. 13, 2015)
K	Declaration of Kirk Johnson (Oct. 14, 2015)
L	Declaration of Michael McInnes (Sept. 25, 2015)
M	Declaration of Jim P. Heilbron (Oct. 8, 2015)
N	Declaration of Lisa D. Johnson (Oct. 12, 2015)
O	Declaration of Michael L. Burroughs (Oct. 12, 2015)

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Q	Declaration of Robert Frenzel (Oct. 15, 2015)
R	Declaration of R. Allen Reaves, Jr. (Oct. 13, 2015)
S	Declaration of James J. Jura (Oct. 12, 2015)

**Alabama Power Company, Georgia Power Company,
Gulf Power Company, Mississippi Power Company,**

Petitioners,

V.

U.S. Environmental Protection Agency, et al.,

Respondents.

No. 15-1371

**CO₂ Task Force of the Florida Electric Power
Coordinating Group, Inc.,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1372

**International Brotherhood of Boilermakers, Iron Ship
Builders, Blacksmiths, Forgers, and Helpers,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1365

**Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.,**

Petitioner,

V.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1373

National Rural Electric Cooperative Association; Arizona Electric Power Cooperative, Inc.; Associated Electric Cooperative, Inc.; Big Rivers Electric Corporation; Brazos Electric Power Cooperative, Inc.; Buckeye Power, Inc.; Central Montana Electric Power Cooperative; Central Power Electric Cooperative, Inc.; Corn Belt Power Cooperative; Dairyland Power Cooperative; Deseret Generation & Transmission Cooperative; East Kentucky Power Cooperative, Inc.; East River Electric Power Cooperative, Inc.; East Texas Electric Cooperative, Inc.; Georgia Transmission Corporation; Golden Spread Electrical Cooperative, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; Minnkota Power Cooperative, Inc.; North Carolina Electric Membership Corporation; Northeast Texas Electric Cooperative, Inc.; Northwest Iowa Power Cooperative; Oglethorpe Power Corporation; PowerSouth Energy Cooperative; Prairie Power, Inc.; Rushmore Electric Power Cooperative, Inc.; Sam Rayburn G&T Electric Cooperative, Inc.; San Miguel Electric Cooperative, Inc.; Seminole Electric Cooperative, Inc.; South Mississippi Electric Power Association; South Texas Electric Cooperative, Inc.; Southern Illinois Power Cooperative; Sunflower Electric Power Corporation; Tex-La Electric Cooperative of Texas, Inc.; Upper

No. 15-1376

Missouri G. & T. Electric Cooperative, Inc.; Wabash
Valley Power Association, Inc.; Western Farmers
Electric Cooperative; and Wolverine Power Supply
Cooperative, Inc.,

Petitioners,

v.

U.S. Environmental Protection Agency,

Respondent.

NorthWestern Corporation
d/b/a NorthWestern Energy,

Petitioner,

v.

U.S. Environmental Protection Agency, et al.,

Respondents.

Tri-State Generation and Transmission Association,
Inc.,

Petitioner,

v.

U.S. Environmental Protection Agency,

Respondent.

No. 15-1378

No. 15-1374

United Mine Workers of America,

Petitioner,

v.

U.S. Environmental Protection Agency,

Respondent.

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) No. 15-1375
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Westar Energy, Inc.,

Petitioner,

v.

U.S. Environmental Protection Agency, et al.,

Respondents.

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**ATTACHMENTS TO MOTION OF UTILITY AND
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ATTACHMENT B

TO

**MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE**

Declaration of John L. Pemberton (Oct. 13, 2015)

**IN THE
UNITED STATES COURT OF APPEALS FOR THE
DISTRICT OF COLUMBIA CIRCUIT**

Utility Air Regulatory Group,

Petitioner,

v.

U.S. Environmental Protection Agency,

Respondent.

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Case No. _____

DECLARATION OF JOHN L. PEMBERTON

I, John L. Pemberton, declare:

1. I am the Senior Production Officer (“SPO”) of Georgia Power Company (“Georgia Power” or the “Company”). As SPO, I oversee Georgia Power’s electricity generation operations and, as part of our generation planning efforts, I rely on information and input from the Company’s transmission planning group. I have been in this role since July 2012. Prior to this position, I served as the Senior Vice President and General Counsel for Southern Company operations and for Southern Nuclear from 2010 to 2012, the Vice President of Governmental Affairs in Southern Company’s Washington D.C. office from 2006 to 2010, and the Director of Federal Affairs for Southern Company from 2004 to 2006. Prior to joining Southern Company, I served as Chief Counsel to the Senate Environment and Public Works Committee from 2000 to 2002 and as Chief of Staff for the U.S. Environmental Protection Agency’s (“EPA”) Office of Air and Radiation from 2002 to 2004.

2. In this declaration, I identify numerous impacts to Georgia Power, its employees, its customers, and its local communities if we are required to undertake steps as outlined in EPA’s

Regulatory Impact Analysis of the Clean Power Plan. Based on EPA's Integrated Planning Model ("IPM") analysis, the impacts to Georgia Power include:

- The premature shuttering of approximately 4,800 megawatts ("MW") of fossil fuel-fired units, constituting more than 20% of Georgia Power's generating capacity, with more than 4,200 MW with a current value of over \$3.7 billion identified for retirement in 2016 alone;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of approximately \$830 million in 2016-2017;
- Costs in excess of \$515 million for needed transmission projects, with approximately \$70 million in costs in 2016-2017;
- Costs in 2016-2017 of \$485 million to compensate for impacts to the fuels program;
- Loss of more than \$8 million in annual property taxes and approximately \$15 million in annual fuel taxes (amounts based on 2014 receipts) used by local governments beginning in 2016; and
- Loss of nearly 800 full-time jobs in 2016-2017 alone.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, Georgia Power would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* <http://www3.epa.gov/airquality/cpp/cpp-final->

rule-ria.pdf. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Georgia Power is a subsidiary of Southern Company, serving customers across the entire state. Georgia Power delivers 2.4 million customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, comprising 37 fossil, nuclear, solar, and hydro-electric generating plants. As the SPO, I and my staff are charged with ensuring the reliability and cost-effectiveness of Georgia Power's generation.

5. Georgia Power is a vertically integrated, regulated utility that not only produces electricity but also ensures the safe, reliable transmission and distribution of that electricity to our customers.

6. Georgia Power has and applies tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process. Every three years, as required by the Georgia Public Service Commission ("PSC"), the Company files an Integrated Resource Plan ("IRP"). The IRP shows how Georgia Power will meet future customer demand for electricity, taking into consideration, for example, any changes to the Company's generation resources. Developing the IRP is a very time-intensive task, and we begin developing the IRP more than a year prior to filing. Georgia Power's next IRP submission is due in January 2016 and preparations are well underway.

7. Georgia Power is required by state law to utilize at least a twenty-year planning horizon, and Georgia Power looks at a longer horizon in some planning decisions. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site,

design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

8. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final Rule" or "Clean Power Plan"). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), available at <http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf>.

9. I hereby rely upon all statements and analyses provided by Kim Greene, Southern Company's Chief Operating Officer, on behalf of the Southern Company system.

10. This declaration is based on my personal knowledge of facts and analysis conducted by Georgia Power and Southern Company staff and me.

SUMMARY OF EPA'S CLEAN POWER PLAN

11. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. The Final Rule establishes interim and final national "performance rates" for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO₂/MWh and 832 lbs CO₂/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and

thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO₂/MWh and 771 lbs CO₂/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state's 2012 generation mix. EPA's goals for fossil fuel-fired generating units in Georgia are shown in the table below.

EPA's Goals for Fossil Fuel-Fired Units in Georgia

	Rate-Based Goal (lbs. CO₂/MWh)	Mass-Based Goal (short tons)
Interim (2022-2029)	1,198	50,926,084
Final (2030)	1,049	46,346,846

EPA'S REGULATORY IMPACT ANALYSIS

12. In performing its Regulatory Impact Analysis of the Final Rule, EPA relied on the IPM to define "a least cost way to achieve the state goals" RIA at ES-4. Through this modeling, EPA developed a "compliance solution" for each state—i.e., the set of plant retirements, shifts in utilization of remaining generation, and new generation that would demonstrate compliance with the Clean Power Plan's required reductions.

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

13. Under EPA's compliance solution, Georgia Power must retire nearly 4,800 MW of fossil fuel-fired units by 2030, as shown in the table below, which constitutes more than 20% of Georgia Power's generating capacity. Of that 4,800 MW, EPA predicts that *more than 4,200 MW will retire in 2016 alone*. To understand the magnitude of these retirements, 1 MW is the average capacity needed to power approximately 600 homes.

Georgia Power Retirements under EPA's Compliance Solution

Unit	Year	Net Summer Peak MW Capacity (GPC Ownership Portion Shown in Parentheses)
Bowen 1-4	2016	3,232
Hammond 1-4	2016	840
McIntosh 1	2016	143
Gaston 1-4	2025-2030	1030 (515)
Scherer 1	2030	817 (69)

As described in Kim Greene's declaration, we have determined some of the immediate and irreparable consequences of these premature retirements for Georgia Power. Although I focus on those harms that would occur as a result of retirements in 2016, even if the retirements identified by EPA in its compliance solution did not occur until 2022 (the first year of the interim compliance periods), Georgia Power would suffer irreparable harm in the near-term given the decisions and actions that would be necessary now to prepare for those retirements.

Impacts to Reserve Margins

14. The retirements shown in EPA's compliance solution reflect Georgia Power retirements of over 4,200 MW in 2016, and overall Southern Company system retirements of over 8,000 MW in 2016. While Georgia Power has its own obligation to meet customer needs, the Company's generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

15. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of

resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

16. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

17. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

18. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One industry measure of sufficient generating resources is to avoid having more than one customer electricity service interruption over a ten-year period. The Southern Company system currently has

sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

19. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to Georgia Power customers from such higher production costs and unserved energy would be approximately \$270 million and \$560 million respectively during the 2016-2017 time period.

20. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be \$158 million of expenditures in 2016-2017. Georgia Power Company's share of spending would be \$102 million.

21. Other than constructing NGCCs, the Company's options for replacing the retired generation are limited. For example, replacing fossil fuel-fired generation, which is available

throughout the day and can be dispatched when needed, with solar generation that is time- and weather-dependent, is problematic. Using EPA's capacity factor assumptions for solar in the southeast, it would take over 75,000 acres of solar panels to replace the energy produced in 2014 by a single one of the plants EPA identifies will retire (Plant Bowen). If Georgia Power were to completely cover the existing plant property with solar panels, it would produce only about 580 MW, or 18% of Bowen's current capacity level. Yet of that 580 MW, and even assuming good weather for solar generation, only about half that energy would be expected to be available during Georgia Power's summer peak, because peak summer electric demand occurs later in the day when solar generation is waning (i.e., because the sun is setting). In the winter, peak electric demand occurs at the coldest part of the day, before sunrise, when solar facilities have yet to begin to produce electricity. Although energy from renewable generation can play an important role in serving customers' energy needs, these intermittent resources are not equivalent to the units identified for retirement.

Impacts to Transmission

22. A preliminary screening analysis was performed by Georgia Power's transmission planning group to assess the impacts to the transmission system due to the unit retirements identified in EPA's compliance solution. I have received the results from Georgia Power's transmission planning group as detailed below. This is the type of information that is utilized as an input in the Company's planning process. The preliminary screening analysis used to determine the transmission system impacts, as well as associated transmission projects and estimated costs, was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a

comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

23. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because neither Georgia Power nor the Southern Company system would be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in Georgia Power's service territory to maintain compliance with NERC Reliability Standards. Specifically, as identified in the table below, at least ten additional transmission projects, including two new line and substation projects, at a cost in excess of \$515 million, will be necessary in Georgia, \$70 million of which would be expended in 2016-2017. These are conservative estimates for numerous reasons, including that they do not account for unserved energy from transmission constraints. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement dates identified in EPA's compliance solution. The new line and substation projects will require from five to eight years to complete. Projects at existing lines and substations will take approximately two to three years to complete. As a result, there will be increased risk to system reliability until these projects can be

completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

Transmission Projects Necessary in Georgia

Project Type	Number of Projects
New Line and Substation Projects	2
Existing Line and Substation Projects	8
Total	10

24. Even if the retirements identified by EPA for 2016 did not occur until 2022, when compliance targets set by the Clean Power Plan become effective, many of the actions identified above would not only still be necessary but would also still need to begin in 2016-2017 in order to minimize the reliability impacts of delivering electric service. Specifically, to accommodate those retirements, Georgia Power would still have to begin the transmission projects that require five years or longer to complete, and the expenditure to support those projects would be in excess of \$57 million in 2016-2017.

Impacts from Fuel Contracts and Inventories

25. Under EPA's compliance solution, across the Southern Company system as a whole, the operating companies will incur costs of approximately \$950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. As referenced by Kim Greene, these include: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural

gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring units' coal inventories (planned burn). Georgia Power will bear \$485 million of these costs as identified below, and once contracts are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to Georgia Power from Fuel Contracts and Inventories

Fuel Costs	Estimated Cost in 2016-2017 (\$2015)
Coal Transportation Agreements	\$405M
Additional Fuel Related Impacts	\$45M
Coal Planned Burn	\$35M
Total	\$485M

Impacts to Local Economies

26. The retirement of the units defined in EPA's compliance solution would have immediate and irreparable impacts on local economies. Over \$8.1 million was generated in property taxes for Plant Bowen and Plant Hammond in 2014. In addition, over the past four years, an average of \$15 million in annual fuel taxes was paid for fuel uses at those plants. After the retirement of these units, the local communities will lose these revenues. These tax dollars are used by local governments to help fund basic services from police and fire protection to sanitation and education. For example, after Georgia Power announced the retirement of Plant Branch in Putnam County (due to other environmental regulations), the county raised property tax rates by 37%. This illustrates actual impacts to local communities which result from plant retirements.

27. In addition to the dramatic reduction in tax base, the 2016 retirements will result in nearly 800 direct job losses, with more losses occurring as additional units are retired. These full time positions with benefits represent over \$110 million of earnings losses in the communities where those employees reside. These lost jobs and earnings would not be recovered through the addition of new NGCCs or renewable generation.

Remaining Useful Life

28. The premature retirement of Georgia Power's units identified in EPA's compliance solution will result in closure of units that otherwise would have been economic to continue operating for many years. Georgia Power has recently invested substantial capital resources in these units, primarily for compliance with other EPA regulations. The net book value of these assets plus the value of environmental projects already underway is over \$3.7 billion as of July 2015.

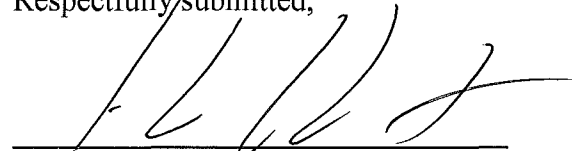
Conclusion

29. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on Georgia Power, its employees, its customers, and the local communities it serves. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve Georgia's electricity needs for many years. The retirements identified in EPA's compliance solution would negatively affect our customers and the communities that we serve by increasing their cost for electricity, risking reliability, dramatically reducing the tax base, and causing substantial job losses.

30. Direct impacts to Georgia Power in excess of \$550 million in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

31. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, Georgia Power would be required to take action and incur approximately \$159 million in costs in 2016-2017 to ensure that it can continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

A handwritten signature in black ink, appearing to read 'J. L. Pemberton', is written over a horizontal line.

John L. Pemberton
Georgia Power, Senior Production Officer

October 13, 2015

ATTACHMENT C

TO

**MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE**

**Declaration of James A. Heidell and Mark Repsher (Oct. 16, 2015)
and attached report
PA Consulting Group, Inc., A Survey of Near-Term Damages Associated with
the EPA's Clean Power Plan (Oct. 16, 2015)**

DECLARATION OF JAMES A. HEIDELL
AND MARK REPSHER

We, James A. Heidell and Mark Repsher, declare under penalty of perjury under the laws of the United States of America that the following is true and correct to the best of our knowledge and belief:

1. I, James Heidell, am a Director at PA Consulting Group ("PA"), 1700 Lincoln Street, Suite 1550, Denver, Colorado 80203. I provide consulting services to the electric utility industry and non-utilities engaged in the production and sale of electricity. I have an MBA in Finance (1989), MS in Engineering Economics (1982) and a BSE in Civil Engineering (1979). I am also a Chartered Financial Analyst.

2. I, James Heidell, have worked for more than twenty years as a consultant to the electric industry and to the U.S. Department of Energy and for ten years as an employee of an electric utility. My work has involved providing economic and technical analysis on a range of regulatory issues, resource planning, and analysis of potential investments in generation. My areas of expertise include energy market modeling and resource planning. I have eight years of experience working in the regulatory department of an investor owned utility in addition to consulting engagements working with the regulatory and planning groups of electric utilities.

3. I, Mark Repsher, am a Managing Consultant at PA Consulting Group, 1700 Lincoln Street, Suite 1550, Denver, Colorado 80203. I provide consulting services to the electric utility industry and non-utilities engaged in the production and sale of electricity, and supporting industries. I have a BA in Economics (2001).

4. I, Mark Repsher, have worked for more than fourteen years in roles as a consultant to the electric industry. My work has involved guiding clients through initiatives spanning strategic resource and environmental compliance planning (for utilities, cooperatives, and municipalities), divestitures of non-core assets to enhance shareholder return, mergers and acquisitions, restructurings and other

litigation, off-take contract structuring and valuation, asset financing, identification of concrete value 'off-ramps' to realize investment returns for specific power assets, and best practice analyses. I have extensively analyzed North American wholesale energy markets, with a focus on coal and environmental regulatory issues.

5. PA's energy industry experience is extensive. We have analyzed and modeled U.S. electricity markets for over twenty five years. Since 2011, our M&A advisory practice has supported more than 150 electric infrastructure purchases, sales, financings and appraisals in every power market in the U.S., including over 200 GW of power generation (including natural gas, coal, hydroelectric, solar and wind). Our electric market modeling uses a mix of third party hourly chronological production cost models and proprietary models. This modeling includes analysis of economic retirements of power plants, forecasts of which plants will install pollution control equipment, and the impacts of environmental regulation. PA's energy practice also includes strategic advisory service to electric utilities, including resource planning.

6. We provide this declaration and the attached report, "A Survey of Near-Term Damages Associated with the EPA's Clean Power Plan," in support of the Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule (the "Final Rule") issued by the United States Environmental Protection Agency ("EPA"). This declaration and the attached report are based on our personal knowledge of facts and analysis conducted by us and staff under our supervision.

7. We have reviewed the Final Rule, the accompanying Regulatory Impact Analysis, and EPA's modeling inputs and assumptions, as well as a number of third party modeling results and assessments of both the Proposed Rule and the Final Rule.

8. Using its Integrated Planning Model (IPM), EPA projects the rule will result in approximately 15 gigawatts (GW) of incremental coal-fired electric generating unit ("EGU") retirements

by 2020 and approximately 27 GW by 2025.¹ In our extensive professional experience, models like IPM are used by agencies like EPA to predict the impacts of regulatory actions under consideration. In this way, agencies like EPA use the models both to help determine the design and stringency of rules, and to predict a wide range of impacts that will result from the rule at hand, including most typically to estimate compliance costs to the regulated sector, broader macroeconomic impacts, impacts to employment, and other measures. For this particular rule, EPA's modeling of the mass-based approach predicts that over 75 percent of the incremental 15 GW of coal fired EGU retirements mentioned above – or close to 11 GW – will actually shut down by the end of 2016. While this fact is not reported by EPA in the preamble to the rule or in its Regulatory Impact Analysis, it is plainly evident by examining the IPM model output files released by EPA.

9. EPA's modeling of the CPP compared the base case, "business-as-usual" scenario of what would happen in the absence of the rule, to what would happen when the rule was promulgated. In order to identify a baseline to measure the impacts of the CPP, the EPA made a series of assumptions and modelled what is anticipated to occur in the next fifteen years without the rule. Under its base case, even without the Final Rule, EPA expects nearly 68 GW of EGUs to retire by 2020. Of this amount, it estimates that 61.4 GW will retire by the end of 2016. This estimate is far greater than what is projected by other analyses, including the U.S. Energy Information Administration's Annual Energy Outlook 2015, which expects only 26 GW of coal retirements between 2015 and 2020 without the Final Rule. The EPA's estimate of retirements through 2016 in the absence of the Final Rule is also double the number of publicly announced retirements, as tracked by PA and SNL Financial.

¹ See EPA, "Regulatory Impact Analysis for the Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," August 2015, at p. 3-34.

10. Based on our review of EPA's analysis and our assessment of the likely base case scenario, which is more closely in line with U.S. Energy Information Administration estimates, we believe that the Final Rule will cause 50 GW of coal-fired EGUs to retire by 2020 – not 15 GW as EPA has estimated – and that those retirements will cause national coal production to decline by approximately 20 percent by 2020 – instead of the 14-17 percent EPA estimated. These retirements and associated impacts will result in immediate and irreversible harm to coal plant owners, coal producers and coal transporters, with secondary impacts to industry, consumers and communities.

11. Based upon our review of available data and of third party analyses and modeling, we estimate that the near-term and irreversible costs associated with the Final Rule include:

- a) Tens of billions of dollars in stranded asset costs of prematurely retired coal plants, along with a material impact to the valuation of plant owners and operators;
- b) Significant resource adequacy concerns resulting from these power plant retirements, which will necessitate billions of dollars in investment in replacement natural gas-fired and renewable generation and related infrastructure such as gas pipelines;
- c) Significant transmission adequacy concerns, which will necessitate billions of dollars in transmission investment to accommodate a substantially different resource mix, including an increased reliance on renewables;
- d) Stranded investments in specialty equipment used by coal producers (e.g., mining equipment) and shippers (e.g., railroad cars, barges);
- e) Material impact to the valuations of coal producers, shippers, and equipment manufacturers;
- f) Direct employment losses of 8000 to 24,000 in the electric power and coal mining sectors, with an estimated 100,000 indirect job losses, and related social costs to communities with few employment alternatives; and

g) Significant reductions in tax revenues to communities where power plant operators are often the largest taxpayer, as well as significant reductions to state shares of federal coal mining royalties and other mining taxes.

12. These damages will predominantly be irreversible because power plant retirement decisions are permanent and often made years before actual retirements take place. Decisions are made years in advance because significant time and costs are required prior to beginning construction of any form of replacement generation to maintain reliability. These costs include time to acquire land and permits, time and expenditures for detailed engineering, transmission planning, permitting, and design, as well as non-refundable deposits for major pieces of equipment such as turbines and generators.

Consequently, in order to have replacement gas-fired or renewable generation placed in service prior to 2022, significant costs would have to be incurred in advance. A reasonable time frame for developing a gas-fired combined cycle plant is on the order of five years.² New power plants and the retirement of existing power plants can also result in the need for new transmission lines for interconnection and to maintain system reliability. The associated transmission construction times vary; in the PJM market, estimates range from 6 to 15 years.³

13. The Final Rule incorporates incentives for the early construction of renewable generation and will encourage the earlier replacement of coal EGUs. Eligible renewable generation in service in 2020 or 2021 will receive additional emission credits provided under the Final Rule's Clean Energy Incentive Program. To receive this additional revenue stream, irreversible decisions to obtain financing for and to construct these renewable resources will need to be made in the 2015-2018 period.

14. Approximately 90 percent of the coal sold in the United States from U.S. mines is

² See, for example, the North American Electric Reliability Corporation ("NERC"), which estimates 64 months. NERC, "Potential Reliability Impacts of the EPA's Proposed Clean Power Plan – Phase I", April 2015, at p. 38.

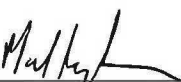
³ PJM, "Reliability Scenario Studies Related to the Proposed Clean Power Plan," July 31, 2015, at p. 6.

supplied to electric utilities.⁴ The coal industry is highly capital-intensive and must make investment decisions with long lead times to adjust to the new market reality that the Final Rule imposes.

Substantial coal EGU retirements will result in an immediate and permanent reduction in the demand for coal. The coal industry thus will suffer immediate irreparable harm as a result of the Final Rule.

15. The immediate and irreversible damages to coal plant owners and coal producers will cascade along the supply chain and adversely impact suppliers of coal transportation service providers, and the equipment suppliers to the associated utility, transportation, and mining industries. Along this chain of events, employees will be displaced and communities heavily dependent on these industries will be adversely impacted.

Executed this 16th day of October, 2015.


James A. Heidell
Mark Repsher

⁴ Energy Information Administration, Short-Term Energy and Winter Fuels Outlook (STEO), October 2015.



AMERICAN COALITION FOR CLEAN COAL ELECTRICITY

A Survey of Near-Term Damages
Associated with the EPA's Clean Power
Plan

October 16, 2015



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1 EXECUTIVE SUMMARY

Key Findings

PA Consulting Group conducted an independent review of publicly available studies, regulatory filings and public documents that discuss the near-term irreparable harm to both communities and industry that will be caused by the Clean Power Plan. The review focused on harms that will be felt almost immediately and will continue through 2022, the first year of the interim period.

Highlights of the economic costs that will be incurred in the near term because of the Clean Power Plan include, but are not limited to:

- **Tens of billions of dollars in stranded asset costs** of prematurely retired coal plants, along with a material impact to the valuation of plant owners and operators.
- **Direct employment losses of up to 24,000** in the electric power and coal mining sectors, with an estimated up to **100,000 indirect job losses**, and related social costs, to communities with few employment alternatives.
- Significant electric reliability concerns, which will only be alleviated by **billions of dollars in replacement natural gas-fired generation and transmission infrastructure** investment.
- **A decline on the order of 20 percent in coal production** and 10 percent in railroad volumes.
- **Increased retail electricity** prices for consumers.

This report additionally documents many other near-term irreparable impacts of the Clean Power Plan on local communities, utilities, independent power producers, coal producers, railroads and other forms of coal transportation.

1.1 Study scope

In August 2015, the U.S. Environmental Protection Agency (“EPA”) announced the final “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units” rule, known as the Clean Power Plan (“CPP”). The CPP aims to reduce emissions of carbon dioxide from the power sector by 32 percent from 2005 levels by 2030. Under the CPP, each state has its own legally enforceable emission reduction target with compliance starting in 2022.¹ Carbon dioxide reductions from the EPA’s 2012 emission rate baseline range from 7 percent in Connecticut to 48 percent in South Dakota.

EPA bases its emission reduction requirements for states on three strategies, which EPA calls “building blocks.” The three building blocks are:

1. Make fossil fuel power plants more efficient (i.e., coal-plant heat rate improvements),
2. Use low-emitting power generation sources more often (i.e., natural gas vs. coal), and
3. Use more zero- and low-emitting power sources (e.g., renewables).

States can use these building blocks, as well as other measures, such as end-use energy efficiency, to meet EPA’s required emissions targets. In addition, states are encouraged to invest in renewables and end-use energy efficiency measures in the 2020-2021 timeframe through the Clean Energy Incentive Program, which will provide matching emission reduction credits. States must file either final plans, or initial submittals seeking a two-year extension with EPA by September 2016.² However, based on the research conducted for this report, it is evident that states and impacted companies need to begin making decisions immediately regarding how to comply with the emission targets set for the start of the compliance period in 2022.

It is anticipated that the CPP will face multiple challenges in federal court that are expected to take years to resolve and litigation could extend to 2019 or even later. Even if one assumes a relatively short period of litigation, it is not feasible to hold off major compliance decisions until 2022 due to the long lead times associated with permitting and construction of new generation and transmission facilities, the modification of existing infrastructure in the U.S. power grid, as well as the ramping up of demand-side energy efficiency programs.³ These decisions, once

¹ The final rule establishes national CO₂ performance standards for two subcategories of existing electric generating units (“EGUs”). Coal and other fossil steam generating units are subject to a CO₂ performance standard of 1,305 lbs/MWh, while natural gas combined cycle units are subject to a CO₂ emission rate of 771 lbs/MWh. To implement these performance standards, each state may adopt plans that either impose these standards on each affected power plant within the state or achieve a state-wide emission reduction target that is based on the application of these performance standards to all affected plants within the state. EPA has established for each state both rate-based and mass-based targets. Each state must then achieve either the rate-based or the mass-based targets through its implementation plan.

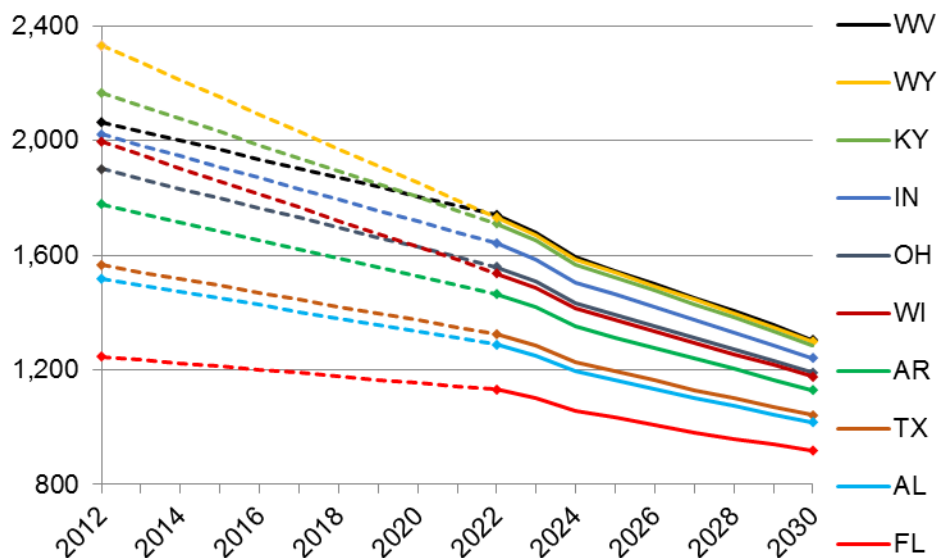
² States can also submit regional plans in coordination with other states. If a state does not submit any implementation plan or EPA does not approve the state’s plan, then the EPA will impose a federal plan.

³ EPA in its final rule assumes a ramping up of demand side energy efficiency reductions to 1.0 percent per year beginning in 2020, for a cumulative 2.1 percent reduction in electricity demand below 2012 levels by 2022 and a nearly 8 percent reduction in overall demand below 2012 levels by 2030. See U.S. EPA. 2015. Technical Support Document (TSD) for the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

made, can create new sunk costs and, particularly in the case of coal plant retirements, are often effectively irreversible. **Consequently, the inevitable near-term decisions that will need to be made years before the 2022 compliance deadline will cause irreversible harm for key constituents.**

This study reviews the estimated impact of the CPP on coal plant owners, electric reliability, railroads, mining companies, and impacted communities during the next few years. This study is not an exhaustive quantification of potential damages; PA Consulting Group (“PA”) selected a few key states to demonstrate some of the impacts in those states. Figure 1-1 identifies these states and shows the varying degrees to which the CPP will require emission reductions. Our findings are based upon our extensive experience in the energy industry and the review and incorporation of well-founded analytics conducted by credible third parties.

Figure 1-1. EPA’s Baseline 2012 Emissions and Emission Targets (2022-2030) by Year (lb/MWh)



1.2 Summary of findings

The EPA projects over 80 gigawatts (GW) of cumulative coal retirements by 2020, of which approximately 13-15 GW (and up to 27 GW by 2025) is attributed to the final CPP.⁴ It similarly projects coal generation to decline 5-6 percent, relative to the base case, by 2020. However, given the substantial uncertainty associated with the CPP and the EPA’s unrealistic assumptions regarding base case coal plant retirements, the potential for far greater retirements as a direct result of the CPP is considerable.

⁴ Modelled estimates vary depending on the approach (rate-based or mass-based) that states employ. See EPA, “Regulatory Impact Analysis for the Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants,” August 2015, at p. 3-34.

For reasons laid out in Section 2.1.1, ***PA anticipates incremental CPP retirements of approximately 50 GW*** and an associated reduction in coal generation of approximately 20 percent by 2020.

The CPP will result in immediate and irreversible costs to stakeholders along the entire utility supply chain because power plant retirement decisions are permanent and often made years before actual retirements take place. These costs include, but are not limited to:

- Tens of billions of dollars in stranded asset costs of prematurely retired coal plants, along with a material impact to the valuation of plant owners and operators;
- Significant resource adequacy concerns resulting from these power plant retirements, which will necessitate billions of dollars in investment in replacement natural gas-fired and renewable generation and related infrastructure such as gas pipelines;
- Significant transmission adequacy concerns, which will necessitate billions of dollars in transmission investment to accommodate a substantially different resource mix, including an increased reliance on renewables;
- Material stranded investments in specialty equipment used by coal producers (e.g., mining equipment) and shippers (e.g., railroad cars, barges);
- Material impact to the valuations of coal producers, shippers, and equipment manufacturers;
- Direct employment losses of approximately 8,000 - 24,000 in the electric power and coal mining sectors, with an estimated 100,000 indirect job losses, and related social costs to communities with few employment alternatives;
- Significant reductions in tax revenues to communities in which power plant operators are often the largest taxpayers, as well as significant reductions to state shares of federal coal mining royalties and other mining taxes; and
- Cascading impacts to industries that service the coal industry (parts manufacturers or operations and maintenance service providers), that depend on low energy prices (such as forging or smelting), or that use coal by-products (such as in the manufacturing of cement or abrasives).

1.3 Basis for our findings

PA Consulting Group analyzed the final CPP and EPA's rulemaking technical analysis and Integrated Planning Model ("IPM") assumptions, and critically reviewed third party studies, however, we did not perform a comprehensive independent modeling analysis of the CPP for this study. PA is recognized for its expertise in analyzing wholesale electric power markets and modeling the impacts of air emission regulations on the power sector. See Appendix A for an overview of PA's qualifications.

1.4 Report organization

The framework for this analysis is discussed in Chapter 2, and explains why coal retirements under the final CPP are likely higher than what EPA has estimated; why and when power plant retirement decisions will be made; and why these decisions are permanent and irreversible. Chapters 3-5 address the resulting irreparable harm to power producers, coal producers, and secondary sectors of impact, respectively. Chapter 6 provides a detailed summary and conclusions.

2 INTRODUCTION AND METHODS

The EPA's rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," and known as the Clean Power Plan ("CPP"), was proposed in June 2014 and finalized in August 2015. The CPP aims to reduce emissions of carbon dioxide (CO₂) from 2005 levels by 32 percent by 2030. Each state will have its own legally enforceable goal. State-level reductions for the rate-based compliance option range from 7 percent in Connecticut to 48 percent in South Dakota below EPA's 2012 baseline.

States will be required to file either final plans, or initial submittals requesting an extension of time to file a final plan with EPA by September 6, 2016. If these submissions demonstrate that a state is on track to develop a final state plan by September 2018, then EPA will give the state until September 6, 2018 to submit their final plans. If a state does not file a sufficient initial submission by September 6, 2016, then EPA will impose a federal plan to ensure state compliance with the CPP's targets. A federal plan will also be imposed if the final state plan does not meet EPA guidelines. EPA states that it will approve or disapprove state plans within a year. States will have to demonstrate in these state plans how they plan to meet the interim target, and will have to file a progress report in 2021. The CPP requires states and regulated electric generating units to begin complying with plans by 2022.

EPA bases the state emission reduction targets for the CPP on three "building blocks":

- **Block 1:** coal-plant heat rate improvements;
- **Block 2:** re-dispatch toward less CO₂-intensive generation (i.e., natural gas); and
- **Block 3:** increasing clean generation (e.g., renewables).

Although the EPA eliminated the proposed rule's fourth building block—reducing electricity use (i.e., increasing end use energy efficiency)—from the final rule, the final rule assumes that energy efficiency will be a necessary part of compliance. To that end, the EPA added a mechanism to incentivize states to invest in energy efficiency (as well as certain renewable resources), which EPA calls the Clean Energy Incentive Program. Under this program, EPA will provide incentive emission reduction credits for investments finalized after the state plans are approved and for generation from those investments that occurs in either 2020 or 2021. Regardless of the mix of implementation strategies incorporated in either state plans or federal plans, the strategies employed will result in significant changes in investments for most states and associated harms to companies, employees, and communities reliant on coal.

Unless the rule is stayed or suspended in the near term, the likelihood of irreparable harm from the rule well before the 2022 compliance deadline is certain. In order to meet EPA's

implementation schedule, industry will need to make immediate compliance decisions, which include an estimated 50 GW of incremental coal retirements. The decisions made regarding CPP compliance will be substantial and largely irreversible. This report lays out the significant irreparable harm that will be incurred by coal plant owners and their communities, mining companies and their communities, and related transportation companies.

2.1 Immediate and near-term economic damages

The decision to close a coal plant and construct alternative generation, and potentially transmission facilities, is the starting point of a cascading set of irreversible decisions. This leads to damages that begin with the coal plant owner and then impact the suppliers of coal transportation service providers, the coal mining industry, and the equipment suppliers to the associated utility, transportation, and mining industries. Along this chain of events, employees are displaced and communities heavily dependent on these industries will be adversely impacted.

Our analysis and experience leads us to conclude that irreversible decisions and steps to comply with the CPP's 2022 reduction requirements will need to occur in the near term. In this section we explain the basic reasoning to support our conclusion both that economic damages will occur in the next few years and that these damages are irreparable. We address the following four key elements to our reasoning:

- The amount of time required to restructure the nation's power supply and grid, and consequently why a 2022 compliance start date requires decisions to be made in the near-term;
- Why many of these near-term decisions are irreversible and permanent;
- Why PA estimates that approximately 50 GW of incremental retirements will occur under the CPP before 2022; and
- Why it is therefore reasonable to conclude, as many affected parties have, that significant harms will occur from these early retirements.

2.1.1 Power plant retirement and replacement decisions are long-dated

Coal-fired power plant retirement decisions and investments in new power plants are made years in advance of a facility's closure, particularly in the case of regulated utilities. A regulated utility must seek regulatory approval to close a coal plant and begin to acquire replacement sources of energy and capacity well in advance of its shutdown.

The EPA anticipates that coal plants will be replaced with a mix of gas-fired power plants and renewable resources such as solar and wind. Solar and wind resources can be physically constructed within two years, whereas combined-cycle plants can take longer, depending on the regulatory environment.⁵ However, significant time and costs are required prior to beginning

⁵ Construction by IPPs in deregulated states such as Texas can generally be completed within 3 years, whereas in regulated states such as Florida it can take significantly longer.

construction of any form of generation. These costs include time to acquire land and permits, time and expenditures for detailed engineering, transmission planning, permitting, and design, as well as non-refundable deposits for major pieces of equipment such as turbines and generators. Consequently, in order to have replacement gas-fired or renewable generation placed in service and operational prior to 2022, significant costs need to be incurred well in advance. As discussed later in this report, the average time frame for developing a gas-fired combined cycle plant is roughly five years.

In reality, decisions to comply with the EPA's interim target in 2022 started even before the rule was published in the Federal Register. Regulatory approvals and environmental air permits need to be obtained well in advance of construction, as do equipment procurement commitments and power purchase agreements. In the case of renewables, projects constructed in the near future remain eligible for production tax credits, which might not be extended, and to qualify for the CPP incentives a unit needs to be placed in service no later than 2021, and ideally before 2020 because incentive credits are only eligible to be received for generation that takes place in 2020 and 2021. Decisions on the construction of new wind and solar generating resources will need to be accelerated in order to qualify to earn the incentive credits that are provided under the Clean Energy Incentive Program. These irreversible decisions will need to be made in 2016, 2017 and 2018 in order to generate incentive credits at the start of the incentive program in 2020.

Regulated utilities that require significant replacement generation may also need to spread the construction costs across over multiple years in order to manage rate increases and pressure from regulators to reduce costs. In some wholesale electricity markets, capacity market rules require retirement decisions to be identified up to four years prior to the delivery year (the period for which the capacity is contracted.)⁶ Finally, PJM notes that construction may occur far earlier than otherwise necessary because "equipment availability leading up to the EPA's interim target may compound lead times."⁷ For these reasons, utility planning for 2022 and beyond has already begun and will continue to intensify over the next few years. This long lead time is implicitly acknowledged by EPA's final rule modeling, which calculates that over 75 percent of the cumulative 2020 coal-fired power plant retirements will have occurred by 2016.⁸

It is also corroborated by company statements. For example, Xcel Energy noted in a recent filing that planned "coal plant retirements ... [through] 2020, are designed in part to reduce future carbon compliance costs for our customers and in part to meet other environmental regulatory obligations."⁹ The Tennessee Valley Authority ("TVA") in its 2014 IRP similarly announced it would retire 13 coal-fired units each in Alabama and Tennessee by 2018 "regardless of the final

⁶ More specifically, units in the PJM market need to request an exemption from the Must Offer Requirement by September 1, approximately 10 months prior to the Base Residual Auction, which is held three years in advance of the delivery year. One such exemption is that the unit will be retired prior to the delivery year.

⁷ PJM, "Reliability Scenario Studies Related to the Proposed Clean Power Plan," July 31, 2015, at p. 6.

⁸ PA Consulting Group analysis of the EPA's IPM v.5.15 run files under the base case and rate- and mass-based compliance scenarios, retrieved at <http://www2.epa.gov/airmarkets/analysis-clean-power-plan>.

⁹ Xcel Energy, Comments on "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014, at p. 49.

form of the rule” to “put TVA on a trajectory toward complying with the CPP.”¹⁰ Coal producer Murray Energy said in its reply brief in litigation related to the CPP that “[t]he mere pendency of the proposed rule causes immediate harm because coal producers and utility customers must make—and are making—current business decisions now.”¹¹

2.1.2 Related infrastructure decisions are even longer-dated

Although the physical construction of power plants takes at least several years, the construction of the necessary infrastructure to support these plants, including natural gas pipelines and transmission lines, can take far longer. Estimates for transmission line construction times vary, but generally range from 6 to 15 years—a recent 765-kV line in PJM’s footprint took 16 years to build.¹² This is particularly the case for replacement generation that cannot be built on existing coal plant sites. Most notably, the substantial build-out of renewables will require significant transmission investment because the most optimal wind sites are often geographically remote from load centers. The siting challenges include substantial acquisition of rights-of-way that can take years to acquire, given the number of stakeholders involved, as well as the allocation of cost recovery for transmission investments among participants in organized markets that in prior instances have dragged out for years. The same logistical challenges apply to natural gas pipelines. The decisions and commitments required to accommodate a substantially different resource mix therefore need to begin immediately in order to meet the start of the first interim compliance period.

2.1.3 Retirement decisions are permanent

Power plant closing decisions are generally considered permanent and irreversible. There are many reasons for this, including substantial costs associated with retiring a unit, which includes tax considerations (such as loss treatment) and decommissioning costs. Additionally, operators will typically avoid all but essential maintenance in the months and years leading up to a retirement, which can create additional substantial maintenance costs if a decision is reversed, and staffing levels are often lowered through layoffs or other avenues in the lead-up to the retirement – forcing personnel to seek employment elsewhere. Duke Energy’s Coal Plant Decommissioning Program outlines what occurs after a coal plant retires:

*The long-term vision for sites with retired coal units across our system is to return them to ground level. During the early stages of the decommissioning and demolition project, we will remove chemicals and other materials, salvage what equipment we can recycle and repurpose at other sites and sell any scrap material. In the demolition and restoration phases, we will safely remove the powerhouse, chimneys and any auxiliary structures no longer needed and then fill, grade and seed the land.*¹³

¹⁰ TVA. 2015 Integrated Resource Plan, at p. 90.

¹¹ Murray Energy Corporation v. EPA, Nos. 14-1112 and 14-1151 (D.C. Cir. filed Feb. 26, 2015).

¹² PJM, “Reliability Scenario Studies,” at p. 6.

¹³ See <https://www.duke-energy.com/about-us/decommissioning-program.asp>.

This process typically takes a year or less: as of September 2015, Duke has decommissioned all 11 of the coal plants it retired in late 2013 and early 2014, and demolished 8 of them.¹⁴

There are regulatory practicalities involved as well, including the certification and permitting of a plant that, once lapsed, are typically very cumbersome to reinstate. Because the retirement process is time- and resource-intensive, companies can elect to “mothball” a unit if there is a reasonable chance that the unit may be needed again. However, even when mothballed, maintenance may be deferred and employees may be terminated.

Finally, once a unit is retired, alternative investments made to replace the unit will result in substantial sunk costs for new generation and potentially new transmission. These new investments will need to be recovered or written off, resulting in costs to ratepayers of regulated utilities and to investors for independent power producers. Hence, a determination to retire a unit is generally permanent and irreversible.

2.1.4 Latest EPA retirement projections due to the CPP are likely low

Any modeling of future market outcomes relies on a number of uncertain assumptions including fuel prices, demand for electricity, tax policies, other regulatory policies, and assumptions regarding recovery of capital costs. The difficulty of projecting future market outcomes is compounded by the inherent uncertainty of predicting future utility planning decisions.¹⁵

For these reasons, modeled projections of coal retirements under the proposed rule varied widely, with EPA’s estimate of nearly 50 GW of retirements in the middle of this range. Since we are not aware of public independent modeling of retirements under the final rule that has been completed as of this writing, we broadly accept EPA’s modeling of over 80 GW of the cumulative (base case plus CPP) coal retirements by 2020,¹⁶ regardless of the attribution to the CPP, as a reasonable estimate. However, we do not accept EPA’s conclusions regarding the amount of retirements that will occur in the base case absent the CPP.

Determining the number of *incremental* retirements due to CPP depends on two separate worldviews: a CPP case and a base (non-CPP) case. Substantial disagreement between PA’s near-term view and EPA’s base case modeling suggests EPA has overestimated base-case retirements and therefore underestimated incremental retirements due to the CPP.

¹⁴ Ibid.

¹⁵ For example, EPA’s modelling projects net coal-fired capacity additions by 2016 in 7 separate states as a result of the CPP’s rate-based approach. This unlikely outcome includes an additional 1,593 MW of coal-fired capacity in Maryland that would have retired in the base case but not under the CPP.

¹⁶ EPA, “Regulatory Impact Analysis for the Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants,” August 2015, at p. 3-34.

EPA predicts that nearly 68 GW will retire by 2020 in the absence of the rule, of which all but 6.4 GW are expected to retire by 2016.¹⁷ This estimate is far greater than what is projected by other analyses, including the EIA's Annual Energy Outlook, which expects only 26 GW of coal-fired EGUs will retire between 2015 and 2020 in the absence of the CPP.¹⁸ The estimate is also **twice as high as the number of announced retirements** tracked by either PA or by SNL Financial.¹⁹ Given the long lead time involved, it is very unlikely that there are significant numbers of coal retirements scheduled for 2016 that have not yet been announced. A unit-level review in the 10 focus states reveals that several of the units projected to retire have cleared in RTO capacity markets for future delivery, meaning they cannot retire. EPA's base case retirements, particularly in the near-term, are therefore substantially overstated.

Furthermore, EPA's base case under the *final* rule projects an additional 20 GW of coal retirements compared to the *proposed* rule's base case. Changes to market fundamentals since June 2014, when the proposed rule was released, have not been substantial enough to suggest such a shift. EIA's near-term coal price projections made in 2015 are more than 20 percent lower than 2014's projections, which is nearly twice the decline in projected natural gas prices.²⁰ This would suggest, all else equal, a relative shift *toward* coal generation.

We also recognize that EPA appears to already be backing away from its own estimates of retirements due to the CPP:

While the separate modeling based on the final rule shows 11 gigawatts of coal-fired generation shutting down in 2016, that modeling is intended merely to illustrate possible effects of the Rule and is not intended to be predictive.²¹

It is not clear what is the value of EPA's estimates of retirements attributable to the CPP are if they are not meant to be predictive.

Furthermore, there is reason to believe that EPA's CPP retirements may actually be understated. This is because the modeling assumptions for meeting emission targets by means other than a shift from coal to gas may be too aggressive. These assumptions include:

- a presumed 2 percent reduction in overall electricity demand by 2022 – and nearly 8 percent by 2030 due to energy efficiency gains (formerly Block 4); and
- renewable generation build-out rates.²²

¹⁷ PA Consulting Group analysis of the EPA's IPM v.5.15 run files under the base case, retrieved at <http://www2.epa.gov/airmarkets/analysis-clean-power-plan>.

¹⁸ EIA Annual Energy Outlook 2015, Table: Electric Generating Capacity.

¹⁹ See "Scheduled and completed coal capacity retirements through 2020, in MW, by NERC region", retrieved at <https://www.snl.com/InteractiveX/article.aspx?id=33957588&KPLT=2>. Data is through September 10, 2015.

²⁰ EIA Annual Energy Outlook 2014 and 2015.

²¹ No. 15-1277 & No. 15-1284 In RE: West Virginia ET AL. In RE Peabody Energy Corporate. On Petition of Extraordinary Writ of Stay EPA's Corrected Response in Opposition, August 31, 2015 p 29.

²² For example, PJM, the operator of the world's largest competitive wholesale electricity market, cautioned that "historical transmission build-out rates are not likely aggressive enough to meet the EPA's wind penetration rate

If the EPA's modeling assumptions are not met as prescribed, CPP compliance would further require states to rely more heavily on a shift from coal to gas, and contribute to additional coal retirements.

Based upon our experience and the reasons laid out in this section, we expect the potential for incremental retirements by 2020 under the CPP to be substantially higher than EPA's rate-based or mass-based final rule estimates of 13 GW and 15 GW, respectively. We believe that EPA has substantially over-estimated base case retirements and that 30 GW of these retirements should be attributed to the CPP instead of the base case. We therefore estimate the CPP will lead to closer to 50 GW of incremental retirements in the next few years.

2.2 Data sources

In this report we cite statements made in relation to the proposed rule rather than the final rule because these sources conform to a market view that is closely aligned with PA's view of coal retirements under the final rule. Estimates for the cascading impacts from greater coal plant retirements—including electric reliability concerns, coal production, demand for coal transportation, job losses and community impacts—all flow from the relative mix of building blocks and other strategies that states may rely upon to meet the CPP's targets. Studies, comments, and public statements made in anticipation of 50 GW of retirements are therefore a more credible indicator of the expected potential for irreparable harm under the final rule than those made in response to EPA's unrealistic market view.

2.3 Scope of study

This report reviews the areas of irreversible economic damage that will be incurred by coal plant owners, the utility supply chain (including mining companies, railroads and equipment manufacturers), and the end users and communities directly impacted by regulation of the existing coal plants under the CPP. We have focused on adverse economic impacts that are not reversible should legal challenges to the CPP be successful. Examples include (1) stranded asset value of closed coal power plants; (2) loss of jobs and the associated financial impacts on individuals and communities; and (3) bankruptcies and companies exiting the business. We also highlight indirect impacts to related industries and communities.

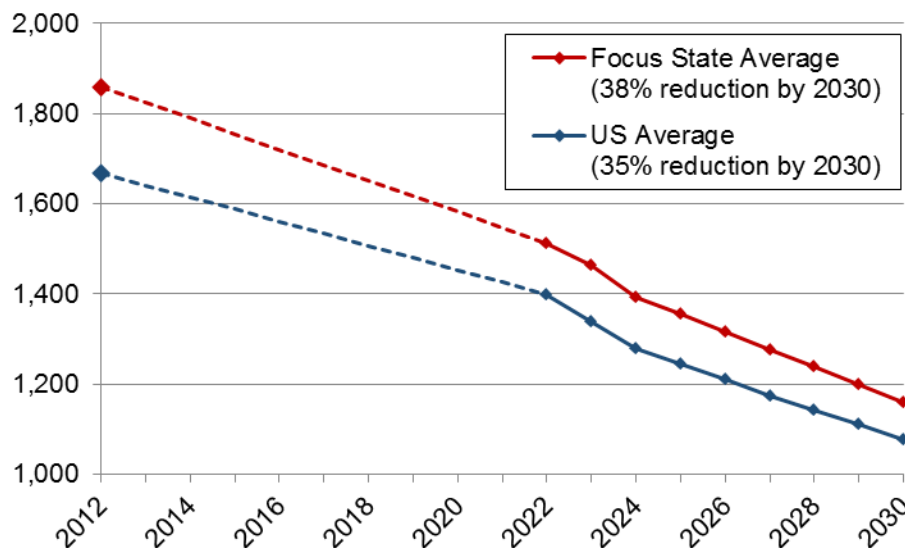
Our conclusions are based upon a number of sources including literature reviews, analyses performed by EPA, EIA and NERC, utility filings, Integrated Resource Plans ("IRPs"), and comments filed with EPA in response to the proposed CPP. We carefully considered the studies performed prior to the final rule to assess their applicability to the final rule. We relied upon those studies to the extent that the analysis is still appropriate. We additionally reviewed third-party sources such as industry and academic studies to compile a qualitative summary of the potential areas of irreparable harm, and relied on primary evidence, such as public statements made by

assumptions." Source: PJM, "Reliability Scenario Studies Related to the Proposed Clean Power Plan," July 31, 2015.)

company officials, to support our findings. PA did not conduct any independent modelling or other quantitative analyses as part of this review.

The harm is anticipated to occur in a large number of states. However, PA selected a subset of states to highlight the harm and limit the scope of the study to states disproportionately impacted by the CPP. The selected states include Alabama, Arkansas, Florida, Indiana, Kentucky, Texas, Ohio, West Virginia, Wisconsin, and Wyoming. Figure 2-1 shows the emission targets for the focus states and the U.S. average. The emission reduction targets are more aggressive for the focus states (38% by 2030 from 2012 levels) than the U.S. on average (35%). Furthermore, these focus states make up 45 percent of national coal-fired electricity generation, 55 percent of anticipated retirements, and 75 percent of total U.S. coal production. Table 2-3 more fully explains the reasons for their inclusion in our study.²³

Figure 2-1. EPA's Baseline Emissions (2012-2021) and Emission Targets (2022-2030) by Year (lb/MWh)



²³ Other criteria considered but not shown include the number of coal mines and employees, share of tax revenues or state GDP from generation or mining, and the headquarters of significant coal producers or shippers, which typically operate across multiple states. Other criteria largely not considered include modelled retirements from sources other than the EPA, which were generally unavailable at the state or unit level or did not isolate the impact of the CPP.

Table 2-3: Coal Production, Generation and EPA-projected CPP Impacts in Focus States²⁴

State	Coal Production, 2014, million tons	Coal Generation, 2014, million MWh	Coal Share of Generation, 2014, %	EPA Net CPP Coal Retirements by 2020, MW*	Reduction From Baseline Rate, Total, lb/MWh	Reduction From Baseline Rate, Total, %
AL	3	47	32	2,417	-500	-27
AR	0.1	33	54	3,718	-649	-44
FL	--	51	22	6,358	-328	-38
IN	38	96	83	400	-799	-20
KY	65	83	92	-1,379**	-880	-18
OH	23	90	67	154	-710	-28
TX	42	148	34	1,447	-524	-38
WI	--	38	62	1,783	-820	-34
WV	63	78	95	0	-759	-20
WY	388	43	88	684	-556	-34

* EPA's original estimate of 49 GW in the Proposed Rule.

** EPA is modeling net capacity additions in Kentucky.

2.4 Report organization

Sections 3 through 5 of this report identify the economic harm to the primary and secondary industry sectors impacted by the CPP, as well as the related harm to the communities in which they operate. We discuss the identified areas of economic harm that will accrue to the owners and operators of power plants in Section 3, and identify the broader harm from reduced electric reliability and the likely costs that will be incurred to avoid this. Section 4 discusses the harm to coal producers. Section 5 examines other harmed entities, including railroad operators and parts manufacturers. Section 6 presents our summary and conclusions.

²⁴ PA Consulting Group, EPA and Energy Information Administration.

3 UTILITIES AND INDEPENDENT POWER PRODUCERS

EPA's emission targets -- derived largely from Building Blocks 2 and 3 of the CPP -- anticipate that states will make a substantial transition from coal-fired to gas-fired and renewable generation by 2022. This presents both technical and economic challenges. Coal plants and their associated boiler technology are generally designed to run continuously and not to significantly ramp up and down. Changing the operational pattern of coal plants by moving them from base load units will result in less efficient operation and potentially higher maintenance costs. This in turn leads to either more expensive operation, or potentially to a decision to close the power plant. For example, Northern States Power explains that such a shift "implies retiring larger, highly efficient and cost-effective base load units, whose generation is expensive to replace."²⁵

This section highlights six areas of economic harm to utilities, independent power producers and other producers of coal-fired electricity and their communities that result from approximately 50 GW of coal-fired retirements under the CPP:

- (1) Tens of billions of dollars of **"stranded asset" value** associated with the premature retirement of coal plants and investments in pollution control equipment;
- (2) Material impact to **company valuations** and associated impacts (such as reduced access to credit markets);
- (3) Tens of billions of dollars for **generation and infrastructure investments** to maintain reserve margins;²⁶
- (4) Tens of billions of dollars for **transmission investments** to maintain grid stability while electrically accommodating a substantially different resource mix;
- (5) Resulting double-digit **increases to electricity rates** for consumers; and
- (6) Approximately 24,000 **direct job losses** and reduced tax revenues to communities.

3.1 Stranded investments and lost value

Coal plants are built, purchased, and financed with an expectation that they will produce power for a long period of time. The capital cost required to build a plant is significant, and it is

²⁵ Northern States Power, Integrated Resource Plan 7, at p. 54.

²⁶ A reserve margin is the excess capacity on hand to meet unforeseen increases in demand. Since there is a cost and a benefit to having excess capacity, the industry standard is a "1-in-10-year loss of load event," or a blackout once a decade.

expected that the plant will recoup this cost over the duration of its technical life (the period that the equipment is functional and can be operated). A coal plant becomes “stranded” when, prior to the end of its technical life, it is unable to earn an economic return due to an unforeseen change, such as a change in regulations. In that case, the economic life of the plant is shortened and the early retirement of stranded assets means that a company may not meet its internal rate of return when it made the investment, and has to take a “write-down” (e.g., the asset is devalued) on the difference between the market value and the book value of the asset.²⁷ For coal-fired power plants, this book value has often increased by subsequent investments in pollution control equipment.

For regulated utilities there are instances where companies may have legal recourse to recover stranded asset costs from their customers. In such instances, the overall economic harm persists but is instead borne by the ratepayer rather than the utility’s shareholders. The coal plants under merchant ownership that will be retired as a result of the CPP will not be able to recover stranded asset costs from their customers and the companies’ investors will be harmed. Regardless of whether stranded costs associated with the CPP are recovered from utility customers or result in lost value for investors, there is substantial harm.

Individual companies and regulatory agencies have estimated the value of stranded assets. These estimates include:

- Wyoming Public Service Commission (“PSC”) projects \$1.49 billion in stranded asset losses as a result of the proposed CPP forcing the closure of four coal-fired plants.²⁸
- Southern Company assessed 9.4 GW of retiring capacity at a net book value of \$4.3 billion;²⁹
- The Jacksonville Electric Authority (“JEA”) in Florida identified \$795 million in stranded costs;³⁰ and
- East Texas Electric Cooperative (“ETEC”) identified \$365 million in stranded costs.³¹

²⁷ In power markets, the competitive market value of assets may be substantially larger or smaller than the net book value, since the price is set not by the average cost but by the marginal cost of power. If a plant operates in a market with excess capacity, the market price may be too low to support the historical capital cost of a plant. See William W. Hogan, “Stranded Assets and the Transition to Competition,” May 1994.

²⁸ Wyoming Public Service Commission, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, PSC Letter Number 14-178, Docket ID No. EPA-HQ-OAR-2013-0602, November 21, 2014.

²⁹ Southern Company, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, December 6, 2014.

³⁰ JEA, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, November 28, 2014.

³¹ Public Utility Commission of Texas, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014, at p.31.

These four estimates suggest that stranded costs are in the hundreds of millions of dollars per GW of capacity.

Stranded costs have the potential to be magnified by the recent and already committed future installation at many stations of environmental controls to comply with other—and at times conflicting—EPA rules, including MATS and the Regional Haze rules. For example, the Lower Colorado River Authority in Texas points to \$400 million in recently-installed scrubbers and mercury emissions control technology that would be stranded if its Fayette Power Project were to retire,³² while the Southwestern Electric Power Company identifies \$870 million in such costs,³³ and Missouri River Energy Services, which owns generation in Wyoming, identified \$125 million.³⁴ According to Seminole Electric Cooperative, the Seminole Generating Station in Florida has a useful life until 2045 and has installed \$262 million in environmental upgrades since 2006, loans related to which mature in 2042.³⁵

Stranded costs also accrue to the remaining coal units that will see reduced dispatch. NERC cautions that the CPP will “change the use of the remaining coal-fired generating fleet from base load to seasonal peaking, potentially eroding plant economics and operating feasibility.”³⁶ For example, EPA projects that Sandy Creek, a 939-MW Texas coal plant built in 2013 with the best available technology, would see its capacity factor decline from 86 to 27 percent.³⁷ Reduced run-hours mean fewer opportunities for coal-fired plants to cover their fixed costs, which reduces their market value.

3.2 Loss of company value

Our review identified a number of instances where companies commented specifically on the financial impact of the still-pending CPP. Many identify the plan (or regulatory changes generally) as a material risk factor to their business. For example, Tampa Electric Company (“TECO”) in Florida points to “increased operating costs, decreased operations... and decreased profitability” as a result of the proposed CPP.³⁸ JEA, based in Jacksonville, Florida and one of the largest community-owned utilities in the United States, notes that “extensive re-dispatch will result in stranded investments at coal-fired [plants]... many states will be required to retire most

³² Lower Colorado River Authority, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014.

³³ PUC of Texas, Comments on CPP, at p. 29.

³⁴ Missouri River Energy Services, “Environmental Protection Agency Clean Power Plan Threatens MRES Resources, Consumers and Reliability,” March 2015.

³⁵ Testimony of Johnson, Lisa. “Testimony of Seminole Electric Cooperative, Inc.” *U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and power, Hearing on the “Ratepayer Protection Act*, April 14, 2015.

³⁶ NERC, “Potential Reliability Impacts of the EPA’s Proposed Clean Power Plan – Phase I”, April 2015.

³⁷ PA Consulting Group analysis of the EPA’s IPM v.5.15 run files under the base case and rate- and mass-based compliance scenarios, retrieved at <http://www2.epa.gov/airmarkets/analysis-clean-power-plan>.

³⁸ Tampa Electric Company, 10-Q Filing, September 2014, at p. 76.

of their coal units before the end of their useful life.”³⁹ Wisconsin Electric Power Company cautions that it may incur “significant additional compliance costs, including capital expenses...and could have a material adverse impact on our operating costs,”⁴⁰ while Madison Gas & Electric stated that it is “reasonable to assume that this rule will have a material impact.”⁴¹

In states with vertically integrated utilities, the cost of shifting from coal to other resources may be borne mostly or entirely by a utility’s customers in the form of higher rates. Wyoming, however, cautions that industrial customers, which make up nearly 60 percent of its customer base, have a significant capacity to self-generate and therefore leave the customer base.⁴² This would hurt the value of companies like PacifiCorp, whose industrial use in Wyoming is 85 percent comprised of mining and extraction,⁴³ industries whose electric demand will already likely be reduced as a result of the CPP. Alternatively, merchant generators and IPPs are unable to pass such costs onto a customer base, and would see company values immediately decline.

3.3 Loss of electric reliability

The retirement of approximately 50 GW of capacity under the CPP has the potential to degrade the reliability of the electric grid. NERC, the entity responsible for reliability in the United States, warned that the proposed CPP would “present challenges”, but its study takes pains to avoid making policy recommendations and instead recommends more time for coordinated planning.⁴⁴ Companies and regional grid operators have taken a stronger stance out of very real concerns regarding reliability impacts from the rule.

The ERCOT reliability study on the proposed CPP projects a reserve margin “considerably less than historically targeted for reliability... occur[ring] toward the beginning of the compliance timeframe,” and suggests the CPP is therefore “likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges.”⁴⁵ MISO similarly states that the proposed CPP is “likely to have a negative impact on electric system reliability” and may “pit environmental compliance against electric reliability.”⁴⁶ Southern Company also identifies “major disruption to system operations and reliability” as a result of the proposed CPP.⁴⁷ While these estimated reliability impacts were based upon the proposed CPP, we do not expect these concerns to be alleviated by changes in the final CPP, such as the extra two years before the start of the initial

³⁹ JEA, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, November 28, 2014.

⁴⁰ Wisconsin Electric Power Company, 10-Q Filing, September 30, 2014, at p. 40.

⁴¹ Madison Gas & Electric Company, 10-Q Filing, March 31, 2015, at p. 17.

⁴² Alan B. Minier, Wyoming Public Service Commission, “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, November 21, 2014 at page 26.

⁴³ Ibid.

⁴⁴ NERC, “Potential Reliability Impacts,” at p. viii.

⁴⁵ ERCOT, “Analysis of the Impacts of the Clean Power Plan,” November 17, 2014, at p. 1.

⁴⁶ MISO, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, November 25, 2014, at pp. 2 and 4.

⁴⁷ Southern Company, Comments, at p. 209.

interim compliance period. As previously noted, there is a significant lead time to permit and construct the new transmission and generation required to address reliability concerns.

3.3.1 Costs to maintain resource adequacy

The primary reliability shortfall is an inability to meet peak demand, known as “resource adequacy.” Several regional studies of the proposed CPP have suggested that reserve margins by 2020 will not be adequate to meet load-serving responsibilities. Southwest Power Pool (“SPP”) identifies a shortfall of 4.6 GW in 2020, while NERC projects the most significant shortfall concerns in MISO and portions of ERCOT.^{48,49} In Florida, which can import just 2.8 GW (approximately 5 percent of its peak demand), the coal units projected to retire by EPA produced nearly 20 percent all the state’s energy in 2014.⁵⁰

Resource adequacy will be compromised if the coal-fired retirements outpace the replacement construction of natural gas-fired and renewable energy units and related infrastructure. Companies and grid operators are projecting significant capital expenditures to avoid such a scenario. Examples include:

- SPP anticipates \$13.3 billion in cumulative capital costs to replace 6.9 GW of retiring capacity;⁵¹
- ERCOT projects \$7-11 billion in cumulative capital costs to replace up to 8.5 GW of retiring coal capacity;⁵²
- In Arkansas, AECC projects \$74 million per year to convert its existing generation from coal to gas;⁵³
- In Texas, ETEC identifies \$585 million in cumulative replacement costs.⁵⁴

These estimates suggest that the replacement cost of retiring capacity is also several hundred million dollars per GW of capacity. As discussed earlier in Section 2.1.1, these costs will begin to be incurred almost immediately because the average time to build a combined cycle, according to NERC, is 64 months.⁵⁵

⁴⁸ Southwest Power Pool, “SPP’s Reliability Impact Assessment of the EPA’s Proposed Clean Power Plan,” October 8, 2014.

⁴⁹ NERC, “Potential Reliability Impacts,” at p. 24.

⁵⁰ Testimony of Lisa Johnson, Seminole Electric Cooperative, *supra* n.35, at p. 21.

⁵¹ Southwest Power Pool, “SPP Clean Power Plan Regional Compliance Assessment”, April 8, 2015, at p. 4.

⁵² ERCOT, “Analysis,” at p. 17.

⁵³ AECC, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014.

⁵⁴ ETEC, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014.

⁵⁵ NERC, “Potential Reliability Impacts,” at p. 38.

3.3.2 Costs to maintain transmission adequacy

In addition to a potential shortage of capacity to meet peak demand and significant expenditures required to ameliorate the shortfall, there is significant potential for irreparable harm associated with maintaining transmission adequacy and avoiding blackouts. These concerns are particularly acute for accommodating significant amounts of renewable generation, because, in contrast to fossil fuel generation, wind and solar generating units are often located far from load centers (due to the nature of wind and solar resources). The final rule's greater reliance on renewable generation will require a significant re-wiring of the grid to accommodate these changing electrical flows. This build-out will need to occur immediately in order for the 2022 emission targets to be met.

NERC modeling expects "challenges in planning and operation" due to "a significant adjustment of expected transmission flows."⁵⁶ In Texas, the projected changing resource mix "introduces changes to operations and expected behaviors of the system,"⁵⁷ "is likely to lead to reduced grid reliability for certain periods and an increase in **localized grid challenges**," and will result in "significant costs not considered" by EPA.⁵⁸ SPP in its CPP analysis identifies "portions of the system in the Texas panhandle... [that] were [predicted to be] so severely overloaded that **cascading outages and voltage collapse** would occur," and that "the most notable [reactive power] deficiencies were found in Texas."⁵⁹ The Public Utility Commission of Texas has identified a specific example of the reliability challenges posed by the CPP: the retiring Welsh units are needed for voltage support to maintain the East HVDC tie between ERCOT and SPP, and insufficient transmission exists to import the capacity needed to replace the retiring units.⁶⁰

Because it is unlikely that regulators and stakeholders would allow for such compromises to grid reliability, it is very likely that significant additional costs will be incurred to maintain transmission adequacy. AEP concluded that in Ohio it would require \$1 to 2 billion in transmission upgrades just to "mitigate reliability violations on the AEP transmission system [in PJM]."⁶¹ PJM separately identified \$4 billion in realized transmission upgrades required to accommodate the changing resource mix resulting from the 18 GW of coal retirements that have occurred in PJM to date.⁶² Given the long lead time required for transmission projects, these costs will start to be incurred in the very near term.

⁵⁶ NERC, "Potential Reliability Impacts," at p. 27.

⁵⁷ Luminant, Comments on CPP, at p. 2.

⁵⁸ ERCOT, "Analysis," at p. 2.

⁵⁹ Reactive power in an alternating current circuit refers to the portion of power in a generating cycle that does not flow toward the load but instead flows back toward the source. Reactive power is important for maintaining voltage levels and network stability. See SPP, "Clean Power Plan Compliance Assessment," October 8, 2014 (emphasis added).

⁶⁰ Public Utility Commission of Texas, Comments on "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014, at p. 28.

⁶¹ AEP, Comments on "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", Docket ID No. EPA-HQ-OAR-2013-0602, December 1, 2014, at p. 6.

⁶² PJM, LLC, "PJM Economic Analysis of the EPA Clean Power Plan Proposal," March 2, 2015, at p. 103.

3.3.3 Additional areas of reliability harm

The timeframe between approval of a final state plan (as late as 2019) and the beginning of the CPP's first compliance period (2022) can be as short as three years.⁶³ If new generation is needed for compliance, capital expenditures could be required in a very compressed timeline. According to a recent NERC survey, the average time required to plan, permit and construct a new combined-cycle facility is 64 months, while transmission lines require 6 to 15 years.⁶⁴ In order to meet the EPA's targets by 2022, the timing issues would bring "compounded issues if significant retirements occur simultaneously".⁶⁵ NERC therefore identifies a "significant reliability challenge, given the constrained time period for implementation."⁶⁶

This presents additional potential for harm. For example, MISO warns of "hasty and perhaps uncoordinated decisions" that would "erode the value of MISO's transmission planning process and reduce the overall value of economic dispatch of the system, thereby unnecessarily increasing electric costs to consumers."⁶⁷ ERCOT projects \$800 million in additional annual system costs if it were to operate at a reserve margin of 6 percent instead of 14 percent.⁶⁸

There is the added potential for economic harm due to **reduced fuel diversity and the increased reliance on natural gas**. Fuel supply risks are greater for natural-gas fired capacity than for coal-fired capacity. Natural gas is not easily stored and depends on a network of pipelines. A period of cold weather in winter 2014 resulted in spot prices for natural gas above \$100 per MMBtu (nearly twenty times typical price levels) in some northern parts of the country and forced outages, whereas hurricanes have previously disrupted pipeline infrastructure in the Gulf States. Hence, a collective shift from coal to gas could reduce reliability and cause irreparable harm even if resource and transmission adequacy is entirely maintained.

3.4 Community harm

Communities that depend on a power plant for employment will suffer significant adverse economic impacts. National studies project between **8,000 and 24,000 in direct job losses in the electric power generation sector**, with one report stating that most job losses would occur in poorer states.⁶⁹ Industrial Economics, Inc. and the Interim Industry Economic Research Fund at the University of Maryland found that the CPP would lead to the loss of 8,000 coal generation jobs due to early plant retirements.⁷⁰ The Economic Policy Institute found that over 11,500

⁶³ State Plans are due no later than September 6, 2018 and are expected to be approved as late as 2019.

⁶⁴ NERC, "Potential Reliability Impacts," at p. 38.

⁶⁵ Ibid., at p. 43.

⁶⁶ Ibid., at p. 43.

⁶⁷ MISO, Comments on CPP, at p. 4.

⁶⁸ ERCOT, <http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf>. "Analysis," at p. 17.

⁶⁹ Bivens, J. "A Comprehensive Analysis of the Employment Impacts of the EPA's Proposed Clean Power Plan," Economic Policy Institute, June 9, 2015.

⁷⁰ Industrial Economics, Incorporated and the Inter-industry Economic Research Fund, Inc. at the University of Maryland, Assessment of the Economy-wide Employment Impacts of the EPA's Proposed Clean Power Plan. April 14, 2015.

electric power generation, transmission and distribution jobs would be lost by 2020.⁷¹ The proposed rule identified, depending on the compliance approach taken, between 16,400 and 24,000 operations and maintenance jobs would be lost due to the retirement of 50 GW of coal generation power plants. These findings are consistent with a survey of recently-announced closures of power plants, which resulted in approximately 1 job loss per 8 MW of capacity.⁷² It should be noted that these figures of job losses do not include the cascading effects of job losses in the mining, transportation, or other sectors, which would bring the total number of lost jobs due to the rule even higher.

Beyond broad surveys, the loss of jobs and community funding is evident in the review of specific power plants, most of which are sited in rural locations. The Texas Municipal Power Agency, which operates a single 470-MW coal plant expected to retire under CPP, projects the loss of 100 employees as well as the loss of \$1 million in payments in lieu of taxes that fund the three school districts in its area.⁷³ Southern Company projects 1,600 job losses and reduced annual income spending by at least \$125 million in its service territory as a direct result of projected retirements under the CPP.⁷⁴

In Arkansas, the “virtually certain” retirement of two 1,600-MW coal plants would have long-lasting impacts on Jefferson and Independence counties, where the plants are located.⁷⁵ (Unemployment rates in these two counties are substantially above the national average, while per capita incomes are approximately 25 percent below the national average.) The two plant closures would result in the layoff of 960 direct jobs and an additional 1,200 indirect jobs and have an economic impact of \$1.2 billion per year, according to AECC testimony at an Arkansas legislative panel.⁷⁶ Finally in Florida, the retirement of the 1,300-MW Seminole plant would remove the largest taxpayer in Putnam County, a federal Historically Underutilized Business Zone (“HUBZone”), and leave unemployed 400 workers.⁷⁷

⁷¹ Bivens, “Comprehensive Analysis,” at p. 13.

⁷² PA Consulting Group survey of SNL news filings on recent coal plant closures. See, for example, AEP’s closures of 5,750 MW of coal-fired generation before May 31, 2015, to comply with the Mercury and Air Toxics Standards, resulting in 600 employee layoffs. Source: Darren Sweeney, MATS ruling not expected to reverse AEP’s W.Va. coal plant closures, SNL, June 30, 2015, retrieved at <https://www.snl.com/InteractiveX/Article.aspx?id=33116610>.

⁷³ Texas Municipal Power Agency, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, November 26, 2014, at p. 5.

⁷⁴ Southern Company, Comments on CPP, at p. 217.

⁷⁵ Arkansas Electric Cooperative Corporation, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units”, Docket ID No. EPA-HQ-OAR-2013-0602, September 26, 2014.

⁷⁶ John Lyon, Arkansas News Bureau, “Utility Officials: EPA Rule May Shut Down Two Arkansas Power Plants,” August 12, 2014. Available at <http://arkansasnews.com/news/arkansas/utility-officials-epa-rule-may-shut-down-two-arkansas-power-plants>.

⁷⁷ Testimony of Lisa Johnson, *supra* n.35, at p. 13.

4 COAL PRODUCERS

The previous chapter documented the level and impact of plant closures associated with the CPP in the near term. The EPA estimated the proposed CPP will result in a 25 to 27 percent reduction in coal production by 2020, while EIA estimates a comparable 20 percent reduction in coal production by 2020 and a 28 percent reduction by 2030.⁷⁸ As previously noted, we believe that more coal-fired power plants will close due to the CPP than EPA's estimates, and hence we believe the demand for coal will decline by more than the 5 - 6 percent EPA projects in its final rule by 2020.⁷⁹

The reduction in coal demand results in:

- Material financial harm to coal producers in the form of reduced profits and lower valuations;
- Stranded asset costs for mining equipment; and
- Harm to communities in the form of **12,000 direct job losses** and substantially **reduced tax revenues and coal mining royalties**, concentrated in a few mining states;

Our assessment of the harm to coal producers and their local economies focuses primarily on Wyoming, Kentucky, and West Virginia. Wyoming is by far the largest coal producer in the country, while Kentucky and West Virginia rank second and third, respectively. Their output, however, is more labor-intensive: the two Appalachian states account for nearly half of all coal workers in the United States.

4.1 Loss of company value

An authoritative and unbiased study of the proposed CPP's impact on coal production comes from EIA, which estimates a 20 percent national reduction by 2020.⁸⁰ Regionally, the impacts are largest in the Interior region, where production is likely to fall by 24 percent, and in the West, where a 22 percent decline is forecasted. The Appalachian region is projected to decline 13 percent, in part because it has already been disproportionately impacted by shifts in marketplace fundamentals. In gross terms, EPA projected a decline in coal production from 844 million tons

⁷⁸ Analysis of the Impacts of the Clean Power Plan, U.S. Energy Information Administration, May 2015. Note the analysis is based upon the AEO 2015 forecast, but not the final CPP.

⁷⁹ PA Consulting Group analysis of the EPA's IPM v.5.15 run files under the base case and rate- and mass-based compliance scenarios, retrieved at <http://www2.epa.gov/airmarkets/analysis-clean-power-plan>.

⁸⁰ Ibid. The final rule estimates a 14 to 17 percent reduction by 2025]. See EPA, "Regulatory Impact Analysis," Table 3-15.

to 616 million tons by 2020 from 50 GW of retiring capacity under the proposed rule.⁸¹ Because mine costs in 2014 averaged \$30.08 per ton, this decline presents a **nearly \$8 billion annual decline in revenues for producers** at current coal prices.⁸² Coal producers warn of a “material adverse impact” and “particular uncertainties.”⁸³

State-level studies are in line with these national estimates. A West Virginia study projects the northern part of the state is likely to be hit disproportionately hard—a 26 percent reduction in coal production—because much of the coal production there is used to source domestic power plants (versus export or metallurgical).⁸⁴ A study by the University of Wyoming suggests a reduction of 200 million tons of coal in Wyoming.⁸⁵ The Rhodium Group presents an even direr scenario for Wyoming, projecting a 47 percent reduction in coal production and \$5.5 billion in foregone production revenues at projected prices in Wyoming.⁸⁶ The EIA’s analysis of the draft CPP had similar results with an estimated reduction of 234 million tons in western coal production in 2020.⁸⁷

Producers of lignite coal are likely to be disproportionately impacted. This is because lignite coal has a relatively low heat content, making it unsuitable for anything but local consumption. If a coal power plant adjacent to a lignite mine retires, the lignite mine is likely to close. By far the largest producer and consumer of lignite coal is Texas, where it is surface-mined in the rural portions of the east and south and burned by adjacent power plants.⁸⁸ In a recent presentation, lignite industry representatives said plants and producers are “uniquely tied” and asked for a categorical exclusion from the CPP on account of the “uniquely larger economic impact of lignite mine-mouth retirements”.⁸⁹ A study by the University of North Texas identified nearly \$2 billion in economic activity as a result of lignite coal, nearly all of which is at risk of irreparable harm under the CPP.⁹⁰

Because stock markets are forward-looking, losses of company value due to reduced demand are already beginning to be reflected in the market. The figure below shows the SNL Coal Index has declined 70 percent since 2012. While other factors have contributed to this decline,

⁸¹ EPA, “Regulatory Impact Analysis”, Table 3-15 at p. 3-36.

⁸² PA Consulting Group and data retrieved from ABB’s Velocity Suite.

⁸³ Arch Coal Inc., Form 8-K filed with the United States Securities and Exchange Commission, September 4, 2014.

⁸⁴ Brian Lego and John Deskins, Bureau of Business and Economic Research, West Virginia University College of Business and Economics, “Coal Production in West Virginia: 2015-2035”, Spring 2015.

⁸⁵ Robert Godby, et. al., Center for Energy Economics and Public Policy, University of Wyoming, “The Impact of the Coal Economy on Wyoming”, February 2015.

⁸⁶ Rhodium Group, “EPA’s Clean Power Plan: Implications for Wyoming Energy Production,” October 7, 2014.

⁸⁷ PA analysis of EIA AEO tables: Analysis of the Impacts of the Clean Power Plan, Table: Coal Production by Region and Type, Case: Multiple Cases, http://www.eia.gov/beta/aeo/#/?id=95-CPP2015®ion=0-0&cases=ref_cpp2015~rf15_111_all&start=2012&end=2040&f=A

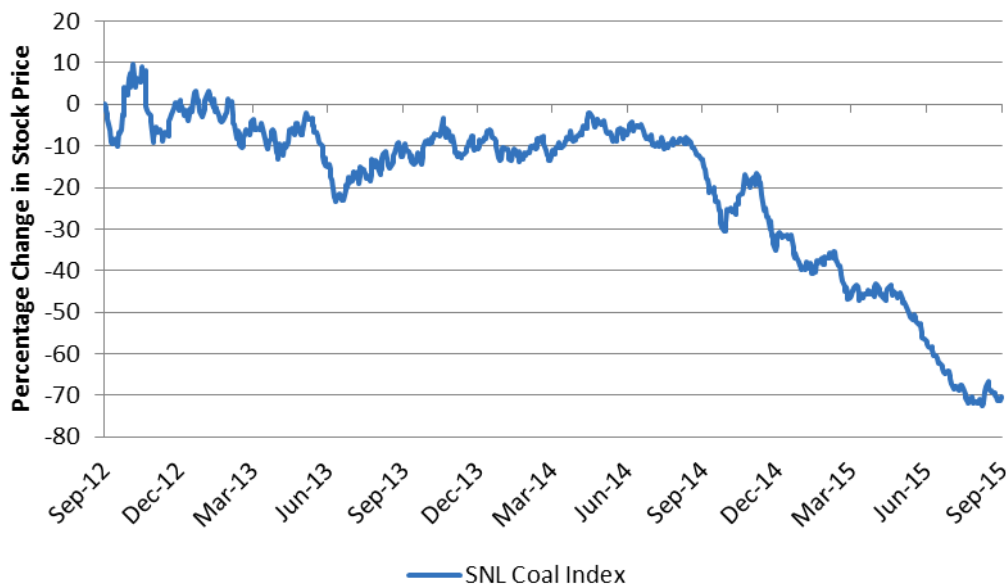
⁸⁸ Over 99 percent of coal mined in Texas is lignite coal, and all of it is consumed in-state. Source: ABB’s Velocity Suite.

⁸⁹ SNL, “Lignite coal industry pushes for exclusion to US EPA’s Clean Power Plan,” July 17, 2015.

⁹⁰ Terry Clower, Manuel Reyes, University of North Texas Center for Economic Development and Research, “Coal Mining and Coal-Fired Power Generation in Texas: Economic and Fiscal Impacts,” February 2013.

including low gas prices and other environmental regulations, it is notable that nearly 90 percent of the reduction has occurred since the proposal of the CPP in June of 2014. The estimated impacts from the Clean Power Plan also contribute to the forecasted reduction in the demand for coal and hence the future earnings of coal producers. The 20-percent reduction in demand for coal due to the irreversible retirement of 50 GW of coal-fired power plants would therefore continue to depress coal producer valuations.

Figure 3-1: SNL Coal Index since September 2012 (% Change)⁹¹



4.2 Loss of asset value

Coal mining, like electric utilities, has a high capital intensity ratio, meaning that the total asset value is inextricably linked to its production. Lower production reduces the utilization and value of digging equipment. In addition to making long-term capital commitments, coal companies also make long-term commitments for coal leases and development of leaseholds. For example, coal companies typically acquire long-term leases for land that run for 20 or more years. According to Arch Coal, after a lease application is made, the application review period can extend from two to five years.⁹² Once leases are awarded, the company must develop the lease and often pay minimum royalties. Consequently, a 20 percent decline in steam coal demand as a result of the CPP would result in substantial reductions in both capital equipment and lease asset values, many with significant remaining life.

This decline in asset value due to reduced demand for coal is evident for economic reasons in the coal industry today. The reduced production in recent years, particularly in the Central

⁹¹ Source: SNL Financial, retrieved September 18, 2015.

<https://www.snl.com/InteractiveX/BriefingBookGraph.aspx?ID=4098789&GraphType=1>

⁹² Arch Coal, Inc. Form 10-K filed with the United States Securities and Exchange Commission, 2014, p. 52.

Appalachian Basin where volumes have declined by over 30 percent since 2011, has resulted in significantly lower asset values. Several coal companies entering bankruptcy in 2014 and 2015 have struggled to sell their distressed assets. SNL noted that many assets have sold for less than 10 percent of what they were worth several years ago.⁹³ Given the strong link between asset value and production, a decline in near-term coal production as a result of the Clean Power Plan would further reduce the asset values of an already strained industry. Unlike regulated utilities, mine operators typically have no mechanism to recover these stranded asset costs.

4.3 Community harm

EPA and the Economic Policy Institute both project a **direct loss of approximately 13,000 employees by 2020 in the coal mining sector** as a result of the reduced demand for coal under the CPP.⁹⁴ Individual state estimates are higher. The University of Wyoming study projects 7,000 job losses in its state, while the lignite industry in Texas directly supports 9,450 employees. The harm to coal mining employees would accrue disproportionately to West Virginia and Kentucky, however, where 42 percent of all coal mining employees and a majority of underground miners work.⁹⁵ Recent closures confirm this—according to SNL Financial nearly two-thirds of mine closures in the first half of 2015 occurred in the “ground zero” Appalachian region.⁹⁶ The replacement work for these employees, to the extent available, is likely to pay much less. The average U.S. coal miner earned over \$82,000 in 2013, which was more than double the median wage in Kentucky and West Virginia.⁹⁷

In addition to employment losses, reduced revenues for mining companies have direct ramifications for state and local funding that depend on the **tax revenues** the companies provide. In Wyoming, where 34 percent of 2014 GDP was from mining,⁹⁸ a 20 percent decline in output would have significant state-wide consequences for residents of the state, and is perhaps enough to contribute to a regional recession.⁹⁹ Luminant in Texas reported \$110 million in 2012 property taxes on its operations—it is the largest generator of electricity in Texas as well as the largest miner and is the top taxpayer in nearly all of the communities in which it operates.¹⁰⁰

The social harm of the CPP will be felt state-wide as well. Most states, including Wyoming, Kentucky and West Virginia, collect coal severance taxes (i.e., an excise tax on resources), proceeds of which are often shared with local governments. In Wyoming, the severance tax accounted for \$274 million in 2014 state funding.¹⁰¹ In Kentucky, the State Budget Director

⁹³ SNL Financial, “Recent coal asset sales in Appalachia show fire sale mentality gripping market,” October 30, 2014.

⁹⁴ EPA “Regulatory Impact Analysis,” at p. 6-25. Bivens, “Comprehensive Analysis,” at p. 9.

⁹⁵ National Mining Association, “U.S. Coal Mine Employment by State, Region and Method of Mining,” 2013.

⁹⁶ SNL, “Narrow band of 16 Central Appalachia counties ‘ground zero’ in coal job free fall,” June 17, 2015.

⁹⁷ National Mining Association, “Annual Coal Mining Wages vs All Industries, 2013,” July 2014.

⁹⁸ Bureau of Economic Analysis, retrieved at <http://www.bea.gov/itable/>.

⁹⁹ The technical definition of a recession is two consecutive quarters of declining GDP.

¹⁰⁰ Energy Future Holdings, “Luminant 101,” March 2013.

¹⁰¹ The State of Wyoming Consensus Revenue Estimating Group, “Wyoming State Government Revenue Forecast, Fiscal Year 2015-Fiscal Year 2020,” January 2015.

identified \$180 million in coal severance collections in Fiscal Year 2015, down from \$298 million as recently as 2012.¹⁰² These collections would be further reduced by tens of millions of dollars annually in the coming years.

Federal revenue sharing also ensures that royalties, mineral leases, and related incomes collected by the Interior Department are partially funneled back to the communities that depend on energy production. In 2014, royalties collected on the 405 million tons of coal mined on federal lands totaled \$700 million, of which approximately half was repatriated to states and used for community development and budgetary needs.¹⁰³ One study from 1995 estimated that such royalties accounted for \$287 million (over \$400 million in 2015 dollars) in Wyoming labor income, and that the majority were earmarked for education accounts.¹⁰⁴ More recently, Wyoming's biannual budget depended on \$631 million in federal coal mining royalties to fund state and local general funds and education initiatives.¹⁰⁵

¹⁰² Office of the State Budget Director, available at <http://www.osbd.ky.gov/>.

¹⁰³ Office of Natural Resources Revenue. Wyoming in 2014 reported \$556 million in coal revenues and \$2.119 billion in total revenues, of which \$1.009 billion (48%) was returned to the state.

¹⁰⁴ Coupal, R., D. Taylor, D. Pindell, L. Cabe. "The Economic Impacts of Bureau of Land Management Revenue-Sharing on the Wyoming Economy," *Report to the Bureau of Land Management*, 1999.

¹⁰⁵ Office of Natural Resources Revenue via Senator Wyden fact sheet. available at <http://www.wyden.senate.gov/download/?id=af917fa6-4e2c-4839-bc70-05d5e495b985&download=1>

5 OTHER AREAS OF HARM

The closure of coal plants and reduced use of coal due to the CPP will result in a reduced demand for coal (discussed in Chapter 4). This reduced demand for coal will have adverse financial impacts to railroads, barge and trucking companies, equipment manufacturers, and consumers of electricity.

With the exception of lignite coal, coal is rarely produced and consumed at the same location. Hence there will be an associated decline in demand for transportation services.¹⁰⁶ Declining demand translates into lower margins and potential stranded assets related to investments in coal loading facilities, rail cars, and barges. The financial impacts include:

- Material financial impact to railroad company valuations due to an estimated 10 percent decline in railroad volumes and 5 percent decline in gross revenues;
- Significant write-down of stranded assets, including rail cars, barges and terminals; and
- Reduction in sector employment.

5.1 Railroads and transportation

5.1.1 Loss of company value

We did not identify any studies that quantify specific impacts of the CPP on coal transportation providers. However, companies have made statements alerting investors of the potential economic impact. For example, CSX has stated that the CPP “could reduce the amount of shipments the Company handles and have a material effect on the Company’s financial condition” and the company predicts “downward pressure on domestic coal volumes”.^{107,108}

Union Pacific projected a “5-7 percent impact” to its \$3 billion annual coal segment.¹⁰⁹ Burlington Northern Santa Fe (“BNSF”), a large operator in the Powder River Basin (“PRB”) in Wyoming, stated that 20 percent of its railroad traffic and 25 percent of railroad industry revenues have traditionally been attributable to PRB coal, and it sees “significant volume disruption” as a result of the CPP.¹¹⁰ In Texas alone, the retiring coal plants paid \$700 million in delivery costs in 2014

¹⁰⁶ With the exception of reduced demand for lignite coal that tends to be mine-mouth operations and hence does not utilize long-haul transportation services.

¹⁰⁷ CSX, Form 10-K filed with the United States Securities and Exchange Commission, December 26, 2014.

¹⁰⁸ CSX 2014 Annual Report at p. 24.

¹⁰⁹ Glass, Doug. Union Pacific Investor Presentation, 2014, at p. 4. available at https://www.up.com/investors/attachments/presentations/2014/analyst_conf/glass.pdf

¹¹⁰ Michael Kahn, “BNSF Sees ‘Stranded Assets’ on Coal Lines,” Electric Co-op Today, June 22, 2015.

to BNSF¹¹¹, which would be halved if Texas reduces its coal-fired generation by 52 percent as predicted by the Public Utility Commission of Texas.¹¹² It is reasonable to assume that the projected decrease in coal demand that the EIA attributes to the CPP will also result in a material decrease in revenues associated with coal shipping. EPA's proposed CPP projected coal production would fall from 844 million tons to 616 million tons by 2020 due to reduced demand from 50 GW of retiring coal plants.¹¹³ Nationwide, coal accounted for nearly 40 percent of all railroad volumes and 19 percent of gross revenues in 2014.¹¹⁴ Hence, by 2020 the CPP could account for approximately **10 percent decline in railroad volumes and a 5 percent decline in gross revenues**.¹¹⁵ Transportation and handling costs in 2014 averaged \$16.31 per ton for deliveries from U.S. coal mines, so the drop in production represents a **\$4 billion annual decline in transport revenues by 2020**.¹¹⁶

5.1.2 Loss of asset value

Railroads have invested heavily in their "coal network" in order to ensure reliable deliveries from the Powder River Basin. BNSF Chairman Matt Rose recently stated in the context of changing energy policies and the CPP that "I don't anticipate that we will see that level of coal volume again. That leaves us with millions of dollars in investment in what will eventually be stranded assets."¹¹⁷ In addition, railroads and other shippers utilize specialized equipment for the transport of coal. Some of these assets would become stranded in the event of a substantial reduction in coal demand. For example, coal barges, which ship 10 percent of U.S. coal primarily along the Ohio and Mississippi Rivers, are designed without a top, whereas other cargo, such as grain, requires closed tops. The recent retirement of a single coal power plant in Pittsburgh idled 60 to 80 barges, according to the CEO of a prominent barge shipper, Campbell Transportation.¹¹⁸ Such equipment must either be retrofit to accommodate other commodities or scrapped and therefore will result in economic harm to coal shipping companies.

5.1.3 Community harm

Railroads in 2014 employed 166,000 people at an average wage of \$86,146. It is likely that a material decline in railroad revenues would impact the employment of train operators and related employees, many of whom would be forced to resort to job prospects that do not pay as well.

¹¹¹ PA Consulting Group and data retrieved from ABB's Velocity Suite.

¹¹² PUC of Texas, Comments on CPP, at p. 49.

¹¹³ The final rule projects a decline to 606 million, a 17 percent decline from a low base case that PA views incorporates far too many coal retirements. EPA, "Regulatory Impact Analysis," at p. 3-33.

¹¹⁴ Association of American Railroads, "Class I Railroad Statistics," May 26, 2015. The amount varies by company. For example, BNSF reported that 22% of its railroad freight revenues came from coal transportation in 2014. (BNSF Railway Company Form 10-K for the Fiscal Year Ended December 31, 2014 p 7.)

¹¹⁵ Because coal production for the electric power sector could fall by as much as 27 percent by 2020, and coal is 40 percent of all railroad volume and 19 percent of gross revenues, railroad volumes could fall by 10 percent (0.27×0.4), and gross revenues could decline by 5 percent (0.27×0.19).

¹¹⁶ ABB's Velocity Suite.

¹¹⁷ Kahn, Michael. "BNSF Sees 'Stranded Assets' on Coal Lines," *Electric Co-op Today*, June 22, 2015.

¹¹⁸ Miller, John W. "The Future of Coal: Barge Firms Scan the Monongahela for New Cargo," *Wall Street Journal*, January 7, 2014.

5.2 Equipment manufacturers

The closure of coal power plants and mines will also create indirect damages associated with a reduction in the demand for heavy equipment to serve these facilities. This in turn will result in lost margins and either loss of employment, or employment dislocations. These damages are more difficult to quantify because their impact is more diffuse. Nevertheless, it is reasonable to recognize that these impacts are real and meaningful. For example:

- The Heritage Foundation has estimated manufacturing sector employment impacts associated with the CPP, including the loss of 41,000 jobs between 2016 and 2019.¹¹⁹
- Caterpillar, a leading supplier of heavy equipment, indicated its concern regarding the impact of the CPP on domestic manufacturing.¹²⁰

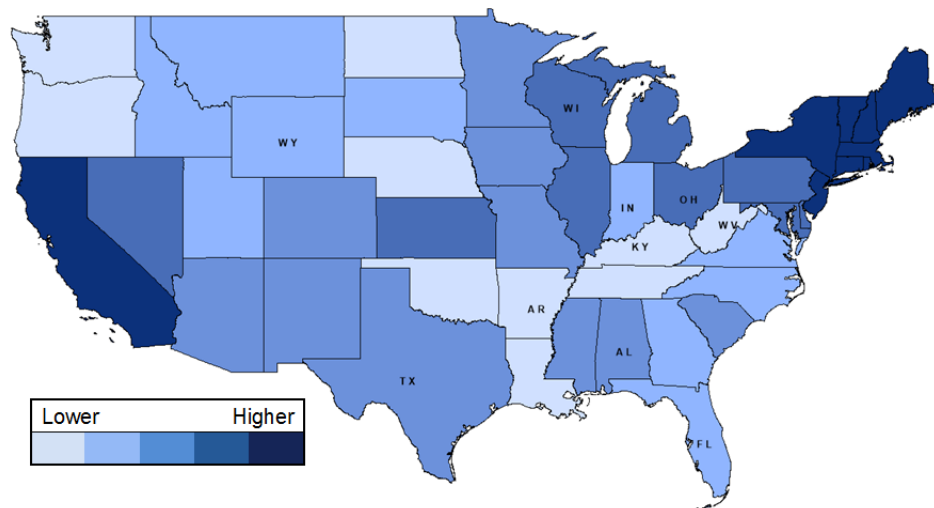
Despite the lack of definitive information, the economic harm is real and it is very likely that there are some small specialized manufacturers that will go out of business.

5.3 Consumers of electricity

Consumers will be impacted by both higher electricity costs as existing coal-fired generation plants are shut down and replaced with other resources, as well as by investments needed to maintain current levels of reliability. Many of the states that will be the most impacted by coal plant closures also have some of the lowest electric rates in the country, as shown in Figure 5-1. The early retirement of those assets and construction of new power plants will increase rates for those consumers.

¹¹⁹ Dayaratna, Kevin D. *The Economic Impact of the Clean Power Plan*, retrieved at <http://www.heritage.org/research/testimony/2015/the-economic-impact-of-the-clean-power-plan>

¹²⁰ Caterpillar Statement on Rep. Ed Whitfield Legislation (Ratepayer Protection Act) in response to CPP, April 29, 2015, available at <http://www.coalzoom.com/article.cfm?articleid=4480>

Figure 5-1: Residential Retail Electric Prices by Quintile, May 2015¹²¹

Not only do the states that are heavily reliant on coal face an increase in electricity prices due to the need to retire and build new power plants, all consumers will face higher prices due to the pressure on natural gas prices caused by the shift to gas. For example, the EIA's May 2015 analysis of the proposed CPP compared to the reference AEO 2015 forecast projected that the price of natural gas delivered to the electric power sector will be 20 percent higher as a result of the proposed CPP.¹²²

State-wide estimates of electricity price increases vary but are all in the billions of dollars, and cumulatively in the tens of billions of dollars. EIA projects a 4.9 percent increase in national electricity prices by 2020, with prices rising nearly 10 percent in some states.¹²³ NERA estimates a 12 percent rise nationally, although prices in some Western states are projected to rise by up to 20 percent.¹²⁴ In Texas, NERA separately projects \$8.7 billion in additional electricity sector costs by 2020 and a 27 percent rise in wholesale electricity prices,¹²⁵ while ERCOT expects a 34 percent rise in locational marginal prices by 2020 under a \$20/ton price on emissions.¹²⁶ The Public Utility Commission in Texas anticipates a total of \$10-\$15 billion in compliance costs will be incurred by entities in Texas.¹²⁷ Finally, ETEC estimates \$2.9 billion in total compliance costs, and an annual rate impact of \$420 to \$480 per customer per year.¹²⁸ ETEC notes that this would be particularly harmful to its poorer, rural ratepayers.

¹²¹ EIA, ABB's Velocity Suite and PA Consulting Group.

¹²² U.S. Energy Information Administration, Analysis of the Impacts of the Clean Power Plan, May 22, 2015, at p. 24.

¹²³ Ibid., at p. 42.

¹²⁴ NERA, "Potential Impacts," at p. 25.

¹²⁵ Luminant, Comments on CPP, at p. vii.

¹²⁶ ERCOT, "Analysis," at p. 15.

¹²⁷ PUC of Texas, Comments on CPP, at p. 2.

¹²⁸ ETEC, Comments on CPP, at p. 1.

These costs will also result in rate impacts that will be felt in regulated regions. In Florida, where nearly all of the coal capacity in the state is expected to retire, the Florida Electric Power Coordinating Group estimates utility cost impacts in the billions—“perhaps tens of billions”—with average rate increases of 25 to 50 percent being a “credible estimate,” according to the chairman of the Florida PSC.¹²⁹ Southern Company projects \$35 billion in upward pressure on electricity rates beginning in 2016.¹³⁰ And in Wyoming, where the majority of electricity in the state is consumed by the industrial sector, some of which has the ability to self-generate, the PUC warned that higher rates to compensate utilities for stranded and new construction costs may be borne by a substantially smaller rate base.¹³¹

¹²⁹ Testimony of Art Graham, Chairman Florida Public Service Commission, before the Committee on Energy and Commerce Subcommittee on Energy and Power, U.S. House of Representatives, March 17, 2015.

¹³⁰ Southern Company, Comments on CPP, at p. 210.

¹³¹ Wyoming Public Service Commission, Comments on CPP, at p. 22.

6 SUMMARY AND CONCLUSIONS

The CPP will require states to develop compliance plans and begin taking actions to comply with the CPP in the very near-term – years before the first interim compliance period begins in 2022. The actions necessary to comply with the CPP are expected to include closing coal plants and investments in alternative technologies. Coal plant closures will have cascading impacts on the transportation industry that delivers coal to the power plants, the coal mines that produce the coal for the power plants, and the manufacturers that provide equipment to these industrial sectors. These damages will predominantly be irreversible.

6.1 Summary of damages

PA Consulting anticipates approximately 50 GW of incremental coal retirements will occur as a result of the CPP during the next few years. This is considerably higher than what EPA projects in its final rule analysis because EPA unrealistically assumes a far higher number of near-term retirements in its base case scenario in the absence of the rule (over 60 GW through 2016 alone in the EPA base case). PA believes that EPA's estimate is inconsistent with current indicators. EPA's estimate is also inconsistent with the EIA's projections.

Because EPA has overestimated base case retirements, and because coal unit retirements are projected to be a major consequence of the CPP's emission rate requirements, EPA has underestimated retirements due to the CPP. As such, we assume that the more than 30 GW of coal retirements unrealistically included in EPA's base case can be attributed instead to the CPP. Because the base case assumptions EPA makes in assessing the impacts of the final rule are unrealistic, this report relies on conclusions drawn by affected entities and third parties in response to the 50 GW of retirements projected under the *proposed* rule, a market view that far more closely aligns with PA's own projections for retirements under the final rule.

We have not attempted to quantify all damages that might result in the near term under the CPP. Instead we focused on a few key states and identified some of the key expected damages from the CPP. The survey of irreparable harm is summarized below.

6.1.1 Costs to coal plant operators

The premature retirement of approximately 50 GW of coal-fired capacity because of the CPP will result in tens of billions of dollars in lost asset value.¹³² These costs are significant, regardless of whether they are recovered from ratepayers through stranded asset charges or represent a loss of value to investors. These losses are exacerbated by recent environmental upgrades made to

¹³² For example, Southern Company expects a \$4.3 billion reduction in the value of its 9.4 GW of retiring plants. See Southern Company, Comments on CPP, at p. 216.

comply with other EPA directives, such as the MATS rule and the Regional Haze rule. The CPP will also impact the operating economics of coal units that are not immediately forced to retire.

6.1.2 Costs to maintain electric reliability

The anticipated coal plant closures are widely projected to reduce reliability in many parts of the country in the short-term and increase costs in the long-term due to investments to maintain reliability. This reduction in reliability will manifest in two primary ways: (1) reduced reserve margins increase the risk of utilities being unable to meet the demand for electricity during peak hours; and (2) local grid stability will be compromised if key power plants are unable to provide reactive power or if transmission upgrades cannot be made on a timely basis to account for the substantially different resource mix. Although the final rule includes a stop-gap “safety valve” designed to address reliability concerns, companies are planning for significant capital expenditures in the near term to address the associated reliability impacts of coal plant closures. These new investments in transmission and generation will likely be demanded by regulators seeking to maintain reliability, and need to be recovered in the market and irreversibly adversely impact the coal related segment of the U.S. generation market.

Investments in gas-fired combined cycle units, the most likely form of replacement generation, will be in the billions of dollars. SPP estimates \$13.3 billion in total capital costs to build 6.9 GW of replacement capacity.¹³³ In addition, billions of dollars in investment will be needed to bolster transmission to accommodate both new gas-fired generation and new non-dispatchable renewables. To maintain grid stability, AEP projects \$1-2 billion for needed grid improvements in their footprint of the PJM market by 2020.¹³⁴

These costs are exacerbated by the short timeframe in which the changes are set to occur, which will likely delay their full replacement by gas-fired generation. For example, ERCOT expects \$800 million in system costs as a result of operating at a reserve margin of 6 percent instead of 14 percent.¹³⁵ There are further costs to reduced fuel diversity when switching from coal to gas, particularly to meet base load, since gas is much more vulnerable to supply disruptions.

6.1.3 Costs to consumers and communities

The coal retirements are projected to result in direct job losses in the electric power sector of 16,000 to 24,000 jobs. These job losses will be concentrated in what are typically small communities where there are few other employment options.¹³⁶ Communities will also suffer

¹³³ SPP Engineering, “SPP Clean Power Plan Regional Compliance Assessment,” April 8, 2015, at p. 4.

¹³⁴ AEP, Comments on CPP, at p. 5.

¹³⁵ ERCOT, “ERCOT Analysis of the Impacts of the Clean Power Plan,” November 17, 2014, at p.17.

¹³⁶ EPA estimates direct job losses of 19,775 by 2020 in the electric power, generation, transmission and distribution sector, while a study by the Economic Policy Institute estimates losses of 11,663. See EPA, “Regulatory Impact Analysis” at p. 6-27; Bivens, J. “A Comprehensive Analysis of the Employment Impacts of the EPA’s Proposed Clean Power Plan,” Economic Policy Institute, June 9, 2015, at p. 9.

from substantially reduced tax revenue as these power plants are often the largest taxpayers in the communities in which they operate.

The costs incurred to prematurely retire coal-fired generation and replace it with natural-gas fired generation will substantially increase electricity prices in many regions. EIA estimated a 4.9 percent increase in electricity prices by 2020 and close to 10 percent in some states.¹³⁷ Other estimates are much higher: Florida's PSC chairman noted that an increase up to 50 percent in Florida is possible.¹³⁸

6.1.4 Costs to coal producers

PA estimates reductions in coal demand in line with EPA's original estimate of approximately 20 percent by 2020.¹³⁹ This would have a direct impact on producers of coal, particularly in Wyoming, West Virginia, and Kentucky. Based on industry data, it is estimated that approximately \$8 billion will be lost in annual revenues, at current prices, for coal producers, and there will be a material impact to the valuations of coal producers. The sharp decline will also result in stranded asset costs for specialized equipment used in the production of coal.

As a result of this reduced demand for coal, studies estimate approximately 13,000 direct job losses in the coal mining sector.¹⁴⁰ In addition to reduced revenues from coal severance taxes and property taxes, states are also set to lose their significant share of federal coal mining royalties, which for some states approach \$1 billion annually. These community impacts will also be felt disproportionately in poor and rural areas.

6.1.5 Costs to railroads and transportation

Because nearly all coal, with the exception of lignite in Texas, is consumed some distance from where it is mined, the reduced domestic demand for coal would also have a direct impact on the operators of railroads, trucks and barges that transport coal from mines to power plants. Burlington Northern Santa Fe (BNSF), a large operator in the PRB in Wyoming, estimates that 20 percent of its railroad traffic and 25 percent of railroad industry revenues are attributable to PRB coal, and sees "significant volume disruption" as a result of the CPP.¹⁴¹ In Texas alone, the retiring coal plants paid \$700 million in delivery costs in 2014 to BNSF¹⁴², which would be halved if Texas reduces its coal-fired generation by 52 percent as predicted by the Public Utility Commission of Texas.¹⁴³ Based on industry data, we estimate that the retirement of approximately 50 GW of coal power generation, at current prices, results in a revenue loss of approximately \$4 billion per year for coal-shipping entities, which would substantially reduce transportation company valuations. As discussed above, EPA itself projects that there will be more than 11 GW of incremental coal retirements due to the final CPP in 2016 alone.

¹³⁷ EIA, "Analysis," at p. 44.

¹³⁸ Graham Testimony, *supra* n.129, at p. 12.

¹³⁹ EPA, "Regulatory Impact Analysis," at p. 3-36.

¹⁴⁰ See EPA, "Regulatory Impact Analysis" at p. 6-26; Bivens, "Comprehensive Analysis" at p. 9.

¹⁴¹ Michael Kahn, "BNSF Sees 'Stranded Assets' on Coal Lines," Electric Co-op Today, June 22, 2015.

¹⁴² ABB's Velocity Suite.

¹⁴³ PUC of Texas, Comments at p. 49.

Transportation companies would also see stranded asset costs for rail infrastructure and for their specialized shipping equipment, such as railcars, barges and terminal. Alternatively, transportation companies would incur costs to retrofit this equipment for other purposes. Transportation companies would also likely reduce the number of employees as a result of lower demand for coal.

6.1.6 Additional impacts

The costs imposed by the CPP will have secondary impacts well beyond the ones felt by coal plant owners, coal producers, transportation companies and the communities in which they operate. These include:

- Additional indirect job losses of approximately 100,000 to the electric power and mining industries;¹⁴⁴
- Increased borrowing costs or reduced access to capital markets for coal producers and consumers as a result of decreased company valuations or credit rating downgrades;
- Reduced service base for manufacturers of coal industry equipment and maintenance service companies;
- Reduced supply and higher costs for industries that use coal by-products as inputs for their own products (e.g., the aggregates industry, which use coal slag as an input for abrasives, or the concrete industry, which uses fly ash as a cementing material); and
- Higher input costs for manufacturing industries, most notably energy-intensive ones such as forging, smelting, or steel production.

6.2 Conclusions

PA has not attempted to develop a precise independent calculation of damages associated with the CPP that will occur in the near term. However, based on a review of publicly available information, we have concluded that the damages will be on the order of billions of dollars starting in 2016. This does not include the harm of difficult to quantify damages associated with individuals who will lose jobs and the communities that have high concentration of employment related to power plants and coal mining. We further conclude that these damages cannot be avoided by delaying action beyond the next few years.

The need to be in compliance in 2022 coupled with the long lead time to retire coal units and build replacement generation and related infrastructure will result in incremental coal plant closures in the near term. Furthermore, those closures will have cascading adverse impacts on coal mining companies, coal transportation services, and equipment manufacturers. Unfortunately, the coal plant closure decisions are not easily reversible as the closures will inevitably be associated with large capital commitments to build alternative generation resources

¹⁴⁴ Bivens, "Comprehensive Analysis," at p. 12.

as well as transmission investments to integrate new generation resources and to maintain reliability of the nation's power grid.

A QUALIFICATIONS

A.1 About PA Consulting Group

PA Consulting Group is a leading management and systems consulting firm. Established 70 years ago and operating worldwide, PA draws on the knowledge and experience of approximately 2,000 people, whose skills span the initial generation of ideas and insights through to implementation.

PA has a team of professionals dedicated to conducting continuous analysis and research on regional North American energy policy and regulation, electric market structure, and electricity market fundamental issues. Our understanding of the past, current, and future dynamics of North American electric market structures has been reflected in the 95+ merger, acquisition, and financing projects we have done with private equity, investment bank, competitive generator, and electric utility clients. Since 2011, PA's M&A advisory practice has supported more than 150 electric infrastructure purchases, sales, financings and appraisals in every power market in the U.S., including over 200 GW of power generation (including natural gas, coal, hydroelectric, solar and wind).

PA's electric market modeling uses a mix of third party hourly chronological production cost models and proprietary models. This modeling includes analysis of economic retirements of power plants, forecasts of which plants will install pollution control equipment, and the impacts of environmental regulation.

PA's electric market advisory services extend beyond market modeling. PA advises dozens of electric utilities and competitive generation owners in developing strategies within their respective regional ISO market rules. PA thoroughly understands ISO market rules and environmental regulations and their impact on all market participants, including electric customers and policy makers. PA also advises Independent System Operators on organizational issues, and advises government agencies, regulators, and utilities on market design.

A.2 About the Primary Authors

James Heidell

James Heidell is a Director at PA and provides consulting services to the electric utility industry and non-utilities engaged in the production and sale of electricity. Mr. Heidell has an MBA in Finance (1989), MS in Engineering Economics (1982) and a BSE in Civil Engineering (1979). He is also a Chartered Financial Analyst.

Mr. Heidell has worked for more than twenty years in roles as a consultant to the electric industry and to U.S. Department of Energy and ten years as an employee of an electric utility. His work has involved providing economic and technical analysis on a range of regulatory issues, resource planning, and analysis of potential investments in generation. His areas of expertise include energy market modeling and resource planning. He has eight years of experience working in the regulatory department of an investor owned utility in addition to consulting engagements working with the regulatory and planning groups of electric utilities.

Mark Repsher

Mark Repsher is a Managing Consultant at PA. Mr. Repsher provides consulting services to the electric utility industry and non-utilities engaged in the production and sale of electricity, and supporting industries. He has a BA in Economics (2001).

Mark Repsher has worked for more than fourteen years in roles as a consultant to the electric industry. His work has involved guiding clients through initiatives spanning strategic resource and environmental compliance planning (for utilities, cooperatives, and municipalities), divestitures of non-core assets to enhance shareholder return, mergers and acquisitions, restructurings and other litigation, off-take contract structuring and valuation, asset financing, identification of concrete value 'off-ramps' to realize investment returns for specific power assets, and best practice analyses. Mr. Repsher has extensively analyzed North American wholesale energy markets, with a focus on coal and environmental regulatory issues.

Pieter Mul

Pieter Mul is a Consultant at PA. Mr. Mul provides consulting services to the electric utility industry and non-utilities engaged in the production and sale of electricity, and supporting industries. He has a BA in Economics (2006).

Mr. Mul has worked for nine years in various capacities in the electric industry and has extensive experience analyzing North American wholesale energy markets for a range of clients. Prior to PA, he spent six years with the independent market monitor to the Midcontinent Independent System Operator, focusing on market operations, market manipulation, capacity market design and wind integration. Prior to this role, he worked for a global law firm assisting tax equity investors with renewable project finance transactions.

ATTACHMENT D

TO

**MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE**

Declaration of Charles R. Patton (undated)

Declaration of Charles R. Patton

I, Charles R. Patton, declare under penalty of perjury under the laws of the United States of America that the following is true and correct to the best of my knowledge and belief.

1. I am the President and Chief Operating Officer of Appalachian Power Company (APCo) and Wheeling Power Company (WPCo), both of which are utility operating company subsidiaries of the American Electric Power Company, Inc. (AEP) System.
2. Since 1995 I have worked for the AEP System or its predecessor companies. I began my career as Director of State Government Affairs for Central and South West Inc., which merged with AEP in 2000. After the merger I held many different positions at AEP, including Vice President of Governmental Affairs from 2002-2004. In 2004 I was named President and Chief Operating Officer of AEP Texas and I served in that capacity until 2008. I became Senior Vice President - Regulatory and Public Policy for AEP in 2008, with responsibility for regulatory and public policy issues, regional transmission policies, strategic coordination of governmental affairs, and the development of compliance programs for the National Electric Reliability Council's (NERC) reliability standards. I assumed my current position in 2010.
3. In my current position I am responsible for all aspects of operations at APCo and WPCo. My primary goals are to oversee the operation of the companies in a responsible and efficient manner, and to ensure that the companies' customers receive safe and reliable electric service at a reasonable price.

4. APCo is a regulated public utility with over one million retail and wholesale electricity customers in Virginia, West Virginia and Tennessee. APCo has over 61,000 miles of transmission and distribution lines, and owns or has long-term power purchase arrangements for approximately 7,300 MW of generating capacity, which is located in Virginia, West Virginia, Ohio, Illinois and Indiana.
5. WPCo is a regulated public utility company serving customers in the northern panhandle of West Virginia. WPCo owns 780 MW of generating capacity located in West Virginia.
6. The purpose of my declaration is to describe how changing environmental requirements have re-shaped the companies' operations, the planning and oversight that are triggered by new environmental requirements, and the time frames associated with changes in the make-up of our generating assets and the supporting transmission network. This declaration is based on my personal knowledge.
7. When I first arrived at APCo in 2010, the company owned and operated 13 coal-fired generating units, 6 natural gas simple cycle combustion turbines, 29 small hydroelectric units, and one pumped storage facility and had long-term power purchase agreements with four wind farms. The company's coal-fired fleet was the backbone of its generation portfolio, producing more than 80% of our annual electricity generation.
8. Within my first two years, the environmental regulatory landscape changed dramatically, as multiple new requirements were proposed and/or finalized by the United States Environmental Protection Agency (EPA). The regulation that had the greatest impact on the composition of our fleet was the Mercury and Air Toxics Standard (MATS), which prescribed stringent emission limitations for mercury, non-mercury metals (measured as

particulate matter) and acid gas emissions that were required to be met at each coal-fired unit, or averaged across all similar units at each facility, by April 15, 2015.

9. When the MATS standards were first proposed in March of 2011, AEP immediately began to assess what these requirements would mean for all of its generating units. By June of that year, AEP announced a preliminary compliance scenario for MATS that involved the following actions across the AEP fleet: retiring 6,000 MW of coal-fired capacity; refueling, retrofitting or upgrading environmental equipment at another 11,000 MW of coal-fired capacity; temporary curtailments to facilitate transitions to retirements or retrofits; and building approximately 1,700 MW of new generation.
10. As the MATS rulemaking progressed, AEP continued to refine its analysis, prepared and submitted detailed comments on the proposed rule, and revised its preliminary plans in light of the actual requirements included in the final MATS rule, which was published in the *Federal Register* on February 16, 2012.
11. For APCo, achieving compliance with MATS required the retirement of 1,270 MW of coal-fired capacity by June 1, 2015¹ -- two units at the Kanawha River Plant, two units at the Sporn Plant, two units at the Glen Lyn Plant and one unit at the Clinch River Plant. Prior to those retirements, APCo completed construction of a new 613 MW natural gas combined cycle facility in Ohio called the Dresden Plant, and acquired an ownership interest in an additional 867 MW of Unit 3 at the coal-fired John E. Amos Plant in

¹ These units did not have the kind of controls necessary to achieve the MATS emission limits for mercury and acid gases. APCo received a 45-day extension of the MATS compliance deadline in order to allow it to fulfill generating unit capacity commitments made to PJM Interconnection, LLC, the regional transmission operator, prior to the proposal of the MATS rule, and to complete transmission upgrades necessary to sustain the reliability of the electricity grid after these unit retirements.

West Virginia. These capacity additions more than offset the coal unit retirements, and allowed APCo to continue to meet its customers' needs for reliable electricity. It is important to note that construction of the Dresden facility had been underway for several years prior to the issuance of the MATS rule.

12. APCo also is still in the process of converting the remaining two units at the Clinch River Plant in Virginia to use natural gas, rather than coal, as fuel. APCo commenced engineering, design and permitting activities for the gas conversion process while it pursued required regulatory approvals. In May of 2013, AEP requested an extension of the MATS compliance deadline for these units from the Virginia Department of Environmental Quality (VDEQ) through April 16, 2016. The extension request was approved on June 3, 2013. Pipeline construction and on-site construction activities are still underway.
13. By April of next year, APCo's portfolio of generating assets will have changed considerably and will include 4 coal-fired generating units, 6 natural gas simple cycle combustion turbines, 2 natural gas fueled steam units, 3 natural gas combined cycle units, 29 small hydroelectric units, and one pumped storage facility. APCo also has long-term power purchase agreements with 2 additional coal-fired power plants and four wind farms. Fossil fuels still provide the majority of the energy used by APCo customers.
14. To implement certain of these changes, APCO was required to seek approval from the public utility regulators in Virginia and West Virginia and the Federal Energy Regulatory Commission (FERC). Specifically, applications for approval of the acquisition of the Dresden Plant (which was already partially constructed) were submitted to utility regulators in Virginia

and West Virginia. The purchase of an additional ownership interest in Unit 3 at the John E. Amos Plant was reviewed by the state utility commissions and FERC. APCO also submitted applications regarding its plan to convert the Clinch River units to burn natural gas to both state utility commissions. Notice of the planned retirement of specific generating units, and applications for approval to construct certain transmission improvements were submitted in advance to PJM Interconnection, LLC (PJM), so that PJM could study the impacts that those retirements would have on the grid, and whether the proposed transmission improvements were the best solutions to mitigate those impacts. Where applicable, APCO also submitted applications for environmental permits and other approvals, and routing selection studies to state agencies in the state(s) where the transmission improvements were located.

15. Development and implementation of a compliance program for the MATS program was a multi-year process. Planning and certain other activities commenced immediately after the 2011 proposed rule was issued, but prior to the issuance of the final rule in 2012. All told, the actions necessary to comply with the MATS rule will have been implemented over the period from March of 2011 through April 16, 2016, a total of 4 years and 11 months, not including the design, permitting, siting, and commencement of construction of the Dresden Plant. APCo also had already completed projects to add air emission controls at its Mountaineer and Amos Plants before the MATS rule was proposed that were sufficient to satisfy its obligations under MATS for those plants.

16. APCo and other utilities also challenged the final MATS rule in court, and pursued that litigation all the way to the United States Supreme Court.² On June 29, 2015, several months after the initial compliance deadline of April 16, 2015, the Supreme Court remanded the case to this court, finding that EPA unreasonably refused to consider costs in determining whether to regulate utility generating units under Section 112 of the Clean Air Act. However, the rule remains in effect, and the majority of the actions necessary to achieve compliance with the MATS rule had already been fully implemented by the time the Supreme Court issued its decision.
17. On June 18, 2014, EPA proposed emission guidelines to reduce greenhouse gas emissions from existing fossil fuel-fired electric generating units (EGUs) that are the subject of the petitions for review filed in these cases. EPA refers to the rule as the Clean Power Plan (CPP). The EPA Administrator signed the final CPP on August 3, 2015. The final rule establishes emission performance standards for affected fossil fuel steam units and NGCC units, and provides alternative state-specific rate- and mass-emission goals. The standards and goals take effect in 2022 and are phased-in until they reach their most stringent levels in 2030. Implementation of the final CPP will occur in accordance with state plans developed by each state and approved by EPA, and EPA has proposed “model” rules that anticipate the development of tradeable credits to facilitate more cost-effective regional compliance strategies. EPA will implement a federal plan for states that fail to submit an approvable plan.
18. All of APCo’s fossil fueled generating assets, with the exception of its simple cycle combustion turbine peaking units, will be “affected facilities” subject to the state plans or the federal plan developed to implement the final

² *Michigan v. EPA*, 135 S. Ct. 2699 (2015).

CPP. Unlike the MATS rule, the exact details of APCo's and WPCo's compliance obligations under the CPP will not be known until a plan (either state or federal) is in place for each of the states with jurisdiction over these companies' affected facilities.

19. The structure and absolute value of the emission performance standards and equivalent rate- or mass-based state goals in the final CPP are significantly different from the structure and values for the requirements in EPA's June 2014 proposal. Prior to the release of the pre-publication rulemaking package on August 3, 2015, no "model" rule language had been proposed by EPA, nor had EPA finalized the methodology that could be used to convert the emission rate standards into mass emission goals. Consequently, as soon as a signed version of the final CPP and the proposed model rules were released, AEP and APCo began to assess the final CPP and proposed "model" rules to determine the achievability of the interim and final goals, and the range of compliance measures that could be included in the state or federal plans.

20. APCo received an information request from the West Virginia Department of Environmental Protection (WVDEP) on August 24, 2015 (attached as Exhibit A), requesting detailed information regarding potential compliance options and their costs, and how characteristics of individual generating units may influence the feasibility and costs of various compliance measures. The Virginia Department of Environmental Quality (VDEQ) issued a notice requesting general input and written public comments to be submitted on the final CPP during the period from August 13 through October 13, 2015, and established dates and times for six public listening sessions at various locations throughout the commonwealth during the public comment period. (See Exhibit B.) APCo will be responding to these

requests to the best of its ability. AEP also has reached out to the state regulators in other states and expects to participate in ongoing discussions with these regulators on behalf of APCo and other AEP subsidiaries.

21. Many states and affected entities have challenged the legal foundation for the CPP, and have submitted petitions for review of the proposed and final CPP. However, EPA established a date certain of September 6, 2016, by which states must submit an initial plan or risk the imposition of EPA's final federal plan. Accordingly, even states with grave doubts about the legality of EPA's actions are proceeding to investigate measures and evaluate compliance options that might be included in a state plan, and will have an obligation to act by September 6, 2016, well before this court will be in a position to issue a decision on the merits in these cases.
22. By September 6, 2016, states are required to submit certain information, including: (1) which options they are considering; (2) what outreach has been conducted; and (3) a schedule of the actions needed to complete a final plan by September 6, 2018, in order to justify extending the date for submitting a final plan.³ Unless a state intends to incorporate by reference the final "model" rules yet to be developed by EPA,⁴ states must investigate a number of issues during the development of their state plans, including: (1) the technical and administrative merits of utilizing a rate-based or mass-based standard; (2) whether the state needs or desires to rely on interstate trading to develop its plan; (3) what actions other states are pursuing and how that may impact utility resources located in other jurisdictions; and (4) whether EPA's requirements for state plans are consistent with or allow the state to take advantage of other state-sponsored CO₂ reduction measures

³ 40 CFR §60.5765.

⁴ EPA has issued proposed model rules, but those proposed rules are currently open for public comment.

(i.e., renewable portfolio standards, energy efficiency requirements, building code revisions, etc.) already in effect or likely to be adopted by the state. APCo has no choice but to play an active role in these proceedings in order to protect its interests and those of its customers in all of the states in which APCo owns affected units, or has long-term contracts for generation and/or serves utility customers.

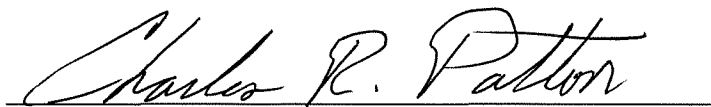
23. By September 6, 2017, the states are required to submit a progress report that includes proposed legislation and draft regulatory requirements that would support submission of a final plan. To accomplish this, within the next 23 months, states and regulated entities like APCo will need to develop a broad enough consensus on the attributes that are most advantageous to include in a state plan, and determine whether such measures can survive the state legislative and regulatory processes necessary to finalize a plan for the Governor to submit to EPA.
24. For utilities like APCo, with operations in multiple states, this must include investigation of alternatives that will be acceptable as compliance options across those multiple states. While the proposed rule would have allowed states three years to make determinations like these in the context of multi-state plans, and would have allowed submission of a final state plan based on proposed legislation and regulatory requirements so long as the actions necessary to finalize those requirements occurred prior to EPA's final approval, EPA has effectively reduced the amount of time available to the states to make these energy and environmental policy decisions and allow for effective public involvement prior to making irrevocable commitments in order to finalize a state plan.
25. Specifically for APCo, the choices made by the states will have significant impacts on the ultimate costs of compliance for APCo customers. After

April 16, 2016, APCo will have only two affected generating units in Virginia, both of which will have been converted to burn natural gas as fuel. APCo will have a natural gas combined cycle (NGCC) plant in Ohio, but that NGCC plant will not be able to meet all of the interim or final emission rate standards in the final CPP, in spite of the fact that the NGCC unit meets EPA's standard for new NGCC facilities on a long-term average basis. APCo also has two coal-fired plants in West Virginia that cannot meet the interim or final performance standards included in the final CPP. Most of APCo's long-term wind contracts are with facilities located in Illinois and Indiana, where it has no fossil fueled facilities and serves no customers.

26. APCo is subject to oversight by the Virginia State Corporation Commission (SCC) and the Public Service Commission of West Virginia (PSC), and was required to submit an integrated resource plan covering the period from 2015 through 2029 to the Virginia SCC in July of 2015. A similar plan for APCo and WPCo is required to be filed in West Virginia by December 31, 2015.
27. The resource plan submitted to the SCC projects the addition of a wide variety of both utility-owned and customer-owned renewable resources and energy efficiency measures. It also discusses the potential need for additional natural gas-fired capacity. If approved and constructed, the near term addition of utility-scale solar and wind resources could take advantage of current tax incentives which are set to expire. Such resources also might qualify for emission reduction credits (ERCs) in a rate-based trading scheme developed under the CPP, but without any certainty about what choices states will make with respect to CPP compliance, the value of any such credits is speculative. In addition, because of the market-based dispatch system in PJM, it is impossible to predict what impact, if any, the addition of renewable resources might have on actual emissions from APCo's coal- or

gas-fired units during any future compliance period under the CPP, and those actual emissions will be the fundamental measure of compliance in a mass-based state or federal plan.

28. The measures included in the resource plan submitted to the SCC, even if approved and constructed, will not allow APCo to demonstrate compliance with the CPP's emission performance goals on a state-by-state basis. EPA's guidelines effectively seek to replace the integrated resource planning process, formerly governed exclusively by APCo's state regulatory commissions, with a national program designed to accelerate the replacement of existing fossil resources with lower or non-carbon emitting resources or reductions in energy demand. As a result, APCo and other vertically integrated utilities will be required to significantly alter their resource choices, schedules, and investment strategies. However, the consequences of prematurely taking actions that are inconsistent with the regulator's preferred planning strategy can include disallowance of cost recovery. APCo experienced just such a result in 2010, when the Virginia SCC disallowed recovery of the costs of certain long-term wind power contracts that were not the most economic resource options available to APCo. (See Exhibit C.)
29. Absent a stay by this court of the aggressive schedule arbitrarily established by EPA, APCo and the states in which it operates will be required to make determinations regarding generating assets, transmission improvements, and other activities in the near term without the benefit of a judicial interpretation of the provisions of the Clean Air Act that EPA claims justify the CPP. Like MATS, determination final decision by this court as to the legality of the CPP could be delayed until well after significant investment decisions, and associated commitments of resources, are made.

A handwritten signature in black ink, reading "Charles R. Patton". The signature is written in a cursive style with a horizontal line underneath it.

Charles R. Patton
President and Chief Operating Office
Appalachian Power Company and
Wheeling Power Company

Exhibit A

RECEIVED AUG 24 2015



west virginia department of environmental protection

Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Phone 304/926-0475 • FAX: 304/926-0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov/daq

August 18, 2015

John M. McManus
Vice President, Environmental Services Division
Appalachian Power Company
1 Riverside Plaza
Columbus, Ohio 43215-2373

RE: Data Request to Coal-Fired Electric Generating Units in West Virginia

Dear Mr. McManus,

In 2015, the West Virginia Legislature adopted House Bill 2004. This Bill added language to W.Va. Code §22-5-20 requiring the Department of Environmental Protection (DEP) to submit a report to the Legislature regarding the feasibility of West Virginia's compliance with the United States Environmental Protection Agency's (USEPA) Clean Air Act section 111(d) rule regulating emissions of greenhouse gases from existing electric generating units. The report must include a comprehensive analysis of the effect of the 111(d) rule on the state. The report and analysis are due within 180 days of USEPA's finalization of this rule. USEPA signed a prepublication version of the rule on August 3, 2015. For your information, I am attaching a copy of enrolled H.B. 2004.

Compliance with the statute will require DEP to obtain unit-specific information for each existing coal-fired electric generating unit in the state. The owners of these units appear to be the best, most reliable sources for the information we are required to consider in preparing this report and analysis. Therefore, I respectfully request that you provide the following information, using both *mass-based* and *rate-based* scenarios, regarding the impact of USEPA's 111(d) rule for each of your electric generating units in the state:

- (1) Consumer impacts, including any disproportionate impacts of energy price increases on lower income populations;
- (2) Nonair quality health and environmental impacts;
- (3) Projected energy requirements;

Promoting a healthy environment.

- (4) Market-based considerations in achieving performance standards;
- (5) The costs of achieving emission reductions due to factors such as plant age, location or basic process design;
- (6) Physical difficulties with or any apparent inability to feasibly implement certain emission reduction measures;
- (7) The absolute cost of applying the performance standard to the unit;
- (8) The expected remaining useful life of the unit;
- (9) The impacts of closing the unit, including economic consequences such as expected job losses at the unit and throughout the state in fossil fuel production areas including areas of coal production and natural gas production and the associated losses to the economy of those areas and the state, if the unit is unable to comply with the performance standard;
- (10) Impacts on the reliability of the system; and
- (11) Any other factors specific to the unit that make application of a modified or less stringent standard or a longer compliance schedule more reasonable.

Based on your fleet mix in West Virginia and considering the primary options USEPA has identified for state plans, please provide your evaluation and recommendations for each unit. Additionally, your analysis of whether the state model rule provided by USEPA is achievable would be appreciated.

Please provide the information requested no later than October 1, 2015 both as hard-copy and electronically in editable format, and signed by a responsible official.

The DEP is open to discussion, suggestions and any additional information that you deem pertinent to this data request. If you have questions about this request or would like to further discuss it, please contact Mr. Thomas Clarke at Thomas.L.Clarke@wv.gov or (304) 926-0499, ext. 1447.

Sincerely,



William F. Durham
Director, Division of Air Quality

Attachment

1 **ENROLLED**

2 **COMMITTEE SUBSTITUTE**

3 **FOR**

4 **H. B. 2004**

5 (By Delegates J. Nelson, Howell, Statler, Walters, Foster, Zatezalo,
6 B. White, Moffatt, Stansbury, Gearheart and Butler)
7

8 [Passed February 19, 2015; in effect from passage.]
9

10 AN ACT to amend and reenact §22-5-20 of the Code of West Virginia, 1931, as amended, relating
11 to the development of a state plan under Section 111(d) of the Clean Air Act; setting forth
12 legislative findings; prohibiting submission of a state plan without authority; requiring the
13 Department of Environmental Protection to study the feasibility of a state plan; requiring the
14 Department of Environmental Protection to submit a report to the Legislature determining
15 whether a state plan is feasible; allowing for the development of a proposed state plan;
16 requiring the state plan to be on a unit-specific basis; allowing for the plan to be on either a
17 rate-based or meter-based standard; allowing for legislative review and consideration prior
18 to submission of a state plan to the Environmental Protection Agency; and creating
19 exceptions to the legal effect of the state plan.

20 *Be it enacted by the Legislature of West Virginia:*

21 That §22-5-20 of the Code of West Virginia, 1931, as amended, be amended and reenacted
22 to read as follows:

23 **§22-5-20. Development of a state plan relating to carbon dioxide emissions from existing fossil**

fuel-fired electric generating units.

(a) Legislative Findings-

(1) The United States Environmental Protection Agency has proposed a Federal Rule pursuant to Section 111(d) of the Clean Air Act, 42 U.S.C. § 7411(d), to regulate carbon dioxide emissions from electric generating units.

(2) The Rule is expected to go into effect on or about June 30, 2015, and will require each state to submit a state plan pursuant to Section 111(d) that sets forth laws, policies and regulations that will be enacted by the State to meet the federal guidelines in the Rule.

(3) The creation of this state plan necessitates establishment and creation of law affecting the economy and energy policy of this State.

(4) The Environmental Protection Agency has stated that any state plan it ultimately approves shall become enforceable federal law upon that State.

(5) The State disputes the jurisdiction and purported binding nature asserted by the Environmental Protection Agency through this Rule, and reserves to itself those rights and responsibilities properly reserved to the State of West Virginia.

(6) Given the economic impact and potentially legally binding nature of the submission of a State Plan, there is a compelling state interest to require appropriate legislative review and passage of law prior to submission, if any, of a state plan pursuant to Section 111(d) of the Clean Air Act.

(b) Submission of a State Plan- Absent specific legislative enactment granting such powers or rulemaking authority, the Department of Environmental Protection or any other agency or officer of state government is not authorized to submit to the Environmental Protection Agency a state plan under this section, or otherwise pursuant to Section 111(d) of the Clean Air Act: *Provided, however,*

1 the Department of Environmental Protection, in consultation with the Department of Environmental
2 Protection Advisory Council and other necessary and appropriate agencies and entities, may develop
3 a proposed state plan in accordance with this section.

4 *(c) Development of a Proposed State Plan-* (1) The Department of Environmental Protection
5 shall, no later than one hundred eighty days after a rule is finalized by the Environmental Protection
6 Agency that requires the state to submit a state plan under Section 111(d) of the Clean Air Act, 42
7 U.S.C. § 7411(d), submit to the Legislature a report regarding the feasibility of the state's compliance
8 with the Section 111(d) Rule. The report must include a comprehensive analysis of the effect of the
9 Section 111(d) Rule on the state, including, but not limited to, the need for legislative or other
10 changes to state law, and the factors referenced in subsection (g) of this section. The report must
11 make at least two feasibility determinations: (i) Whether the creation of a state plan is feasible based
12 on the comprehensive analysis; and (ii) whether the creation of a state plan is feasible before the
13 deadline to submit a state plan to Environmental Protection Agency under the Section 111(d) Rule,
14 assuming no extensions of time are granted by Environmental Protection Agency. If the department
15 determines that a state plan is or is not feasible under clause (i) of this subsection, the report must
16 explain why. If the department determines that a state plan is not feasible under clause (ii) of this
17 subsection, it shall explain how long it requires to create a state plan and then endeavor to submit
18 such a state plan to the Legislature as soon as practicable. Such state plan shall be on a unit-specific
19 performance basis and shall be based upon either a rate-based model or a meter-based model.

20 (2) If the department determines that the creation of a state plan is feasible, it shall develop
21 and submit the proposed state plan to the Legislature sitting in Regular Session, or in an extraordinary
22 session convened for the purpose of consideration of the state plan, in sufficient time to allow for the

1 consideration of the state plan prior to the deadline for submission to the Environmental Protection
2 Agency.

3 (3) In addition to submitting the proposed state plan to the Legislature, the department shall
4 publish the report and any proposed state plan on its website.

5 (d) If the department proposes a state plan to the Legislature in accordance with subsection
6 (c) of this section, the department shall propose separate standards of performance for carbon dioxide
7 emissions from existing coal-fired electric generating units in accordance with subsection (e) of this
8 section and from existing natural gas-fired electric generating units in accordance with subsection (f)
9 of this section. The standards of performance developed and proposed under any state plan to comply
10 with Section 111 of the Clean Air Act should allow for greater flexibility and take into consideration
11 the additional factors set forth in subsection (g) of this section as a part of any state plan to achieve
12 targeted reductions in greenhouse gas emissions which are equivalent or comparable to the goals and
13 marks established by federal guidelines.

14 (e) **Standards of performance for existing coal-fired electric generating units.** – Except
15 as provided under subsection (g) of this section, the standard of performance proposed for existing
16 coal-fired electric generating units under subsection(c) of this section may be based upon:

17 (1) The best system of emission reduction which, taking into account the cost of achieving the
18 reduction and any nonair quality health and environmental impact and energy requirements, has been
19 adequately demonstrated for coal-fired electric generating units that are subject to the standard of
20 performance;

21 (2) Reductions in emissions of carbon dioxide that can reasonably be achieved through
22 measures undertaken at each coal-fired electric generating unit; and

1 (3) Efficiency and other measures that can be undertaken at each coal-fired electric generating
2 unit to reduce carbon dioxide emissions from the unit without switching from coal to other fuels or
3 limiting the economic utilization of the unit.

4 **(f) Standards of performance for existing natural gas-fired electric generating units.**

5 – Except as provided in subsection (g) of this section, the standard of performance proposed for
6 existing gas-fired electric generating units under subsection (c) of this section, may be based upon:

7 (1) The best system of emission reduction which, taking into account the cost of achieving the
8 reduction and any nonair quality health and environmental impact and energy requirements, has been
9 adequately demonstrated for natural gas-fired electric generating units that are subject to the standard
10 of performance;

11 (2) Reductions in emissions of carbon dioxide that can reasonably be achieved through
12 measures at each natural gas-fired electric generating unit; and

13 (3) Efficiency and other measures that can be undertaken at the unit to reduce carbon dioxide
14 emissions from the unit without switching from natural gas to other lower-carbon fuels or limiting
15 the economic utilization of the unit.

16 **(g) Flexibility in establishing standards of performance.** – In developing a flexible state
17 plan to achieve targeted reductions in greenhouse gas emissions, the department shall endeavor to
18 establish an achievable standard of performance for any existing fossil fuel-fired electric generating
19 unit, and examine whether less stringent performance standards or longer compliance schedules may
20 be implemented or adopted for existing fossil fuel-fired electric generating units in comparison to the
21 performance standards established for new, modified or reconstructed generating units, based on the
22 following:

1 (1) Consumer impacts, including any disproportionate impacts of energy price increases on
2 lower income populations;

3 (2) Nonair quality health and environmental impacts;

4 (3) Projected energy requirements;

5 (4) Market-based considerations in achieving performance standards;

6 (5) The costs of achieving emission reductions due to factors such as plant age, location or
7 basic process design;

8 (6) Physical difficulties with or any apparent inability to feasibly implement certain emission
9 reduction measures;

10 (7) The absolute cost of applying the performance standard to the unit;

11 (8) The expected remaining useful life of the unit;

12 (9) The impacts of closing the unit, including economic consequences such as expected job
13 losses at the unit and throughout the state in fossil fuel production areas including areas of coal
14 production and natural gas production and the associated losses to the economy of those areas and
15 the state, if the unit is unable to comply with the performance standard;

16 (10) Impacts on the reliability of the system; and

17 (11) Any other factors specific to the unit that make application of a modified or less stringent
18 standard or a longer compliance schedule more reasonable.

19 **(h) Legislative consideration of proposed state plan under Section 111(d) of the Clean**
20 **Air Act.-** (1) If the department submits a proposed state plan to the Legislature under this section, the
21 Legislature may by act, including presentment to the Governor, (i) authorize the department to submit
22 the proposed state plan to the Environmental Protection Agency, (ii) authorize the department to

1 submit the state plan with amendment, or (iii) not grant such rulemaking or other authority to the
2 department for submission and implementation of the state plan.

3 (2) If the Legislature fails to enact or approve all or part of the proposed state plan, the
4 department may propose a new or modified state plan to the Legislature in accordance with the
5 requirements of this section.

6 (3) If the Environmental Protection Agency does not approve the state plan, in whole or in
7 part, the department shall as soon as practicable propose a modified state plan to the Legislature in
8 accordance with the requirements of this section

9 (1) **Legal effect.** – Any obligation created by this section and any state plan submitted to the
10 Environmental Protection Act pursuant to this section shall have no legal effect if:

11 (1) the Environmental Protection Agency fails to issue, or withdraws, its federal rules or
12 guidelines for reducing carbon dioxide emissions from existing fossil fuel-fired electrical generating
13 units under 42 U.S.C. §7411(d); or,

14 (2) a court of competent jurisdiction invalidates the Environmental Protection Agency's
15 federal rules or guidelines issued to regulate emissions of carbon dioxide from existing fossil fuel-
16 fired electrical generating units under 42 U.S.C. §7411(d).

17 (j) *Effective date.* -- All provisions of this section are effective immediately upon passage.

Exhibit B

**COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
Notice of Public Comment Period
Regarding the Clean Power Plan**

The Department of Environmental Quality (DEQ) is announcing an informal public comment period on the U.S. Environmental Protection Agency (EPA) Clean Power Plan. The plan has been established to cut carbon emissions (greenhouse gases) from existing power plants that generate electricity from fossil fuels. These new EPA rules may have a significant impact on the Commonwealth. Therefore, prior to taking any formal action, DEQ is gathering general input from the public to help inform the Commonwealth's review and implementation of EPA's final rules for existing power plants (see implement EPA's emission guidelines for existing power plants (see EPA's website at <http://www2.epa.gov/carbon-pollution-standards>).

In addition to receiving general input from the public, the Commonwealth is also interested in identifying and collecting input from vulnerable and overburdened communities. These communities include low-income communities, communities of color, areas where people are most vulnerable to climate change, and communities where economies may be affected by changes in the utility power and related sectors.

How to comment to DEQ: You may email written comments to ghq@deq.virginia.gov, send a fax (804-698-4510), or send postal mail to the Air Division, Department of Environmental Quality, PO Box 1105, Richmond VA 23218 from August 13 to October 13, 2015. Please provide your full name, address and telephone number. Note that there is no formal Commonwealth proposal available for comment at this time, and that DEQ will not be preparing a response to comments.

Public listening sessions: DEQ will meet informally with the public to receive public input on the best way for Virginia to implement EPA's carbon reduction plan for existing power plants at a series of listening sessions around the state. The only topic under consideration will be the plan for existing power plants. These listening sessions are only for receiving input from the public, and there will be no formal presentations from DEQ. The dates and times of these listening sessions will be announced shortly.

Federal information: EPA has also issued two other rules for the control of carbon dioxide (CO₂) from power plants:

- Final new source performance standard for new power plants.
- Proposed federal plan and model rule for existing power plants. This rule is open for public comment; follow EPA's instructions in the preamble to the rule.

You can learn more about these rules at EPA's website: <http://www2.epa.gov/carbon-pollution-standards>.

Virginia information: DEQ has established a web page with information about Virginia's actions for meeting the federal requirements: <http://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx>. This page will be updated periodically as new information and opportunities for public comment become available.

**COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
Notice of Public Listening Sessions
Regarding the Clean Power Plan**

The Department of Environmental Quality (DEQ) is announcing a series of informal listening sessions on the U.S. Environmental Protection Agency (EPA) Clean Power Plan to cut carbon emissions (greenhouse gases) from existing power plants that generate electricity from fossil fuels. These new EPA rules may have a significant impact on the Commonwealth. Therefore, prior to taking any formal action, DEQ is gathering general input from the public to help inform the Commonwealth's review and implementation of EPA's final rules for existing power plants (see EPA's website at <http://www2.epa.gov/carbon-pollution-standards>).

In addition to receiving general input from the public, the Commonwealth is also interested in identifying and collecting input from vulnerable and overburdened communities. These communities include low-income communities, communities of color, areas where people are most vulnerable to climate change, and communities where economies may be affected by changes in the utility power and related sectors.

Public listening sessions:

- September 16, 2015: Conference Room, DEQ Valley Regional Office, 4411 Early Rd, Harrisonburg, VA, 5:00 to 8:00 p.m.
- September 22, 2015: Conference Room, DEQ Blue Ridge Regional Office, 3019 Peters Creek Rd, Roanoke, VA, 5:00 to 8:00 p.m.
- September 28, 2015: Cafeteria, Fairfax County South County High School, 8501 Silverbrook Rd, Lorton, VA, 5:00 to 8:00 p.m.
- September 30, 2015: Board of Supervisors Board Room, Henrico County Government Center, 4301 East Parham Rd, Henrico, VA, 5:00 to 8:00 p.m.
- October 1, 2015: Goodloe Center, Phillips-Taylor Hall, Mountain Empire Community College, 3441 Mountain Empire Road, Big Stone Gap, VA, 5:00 to 8:00 p.m.
- October 6, 2015: The Forum, Building A (Room A101), Tidewater Community College, 120 Campus Drive, Portsmouth, VA, 5:00 to 8:00 p.m.

The only topic under consideration will be the plan for existing power plants. These listening sessions are only for receiving input from the public, and there will be no formal presentations from DEQ.

How to comment to DEQ: In addition to attending a DEQ listening session, you may also email written comments to ghg@deq.virginia.gov, send a fax (804-698-4510), or send postal mail to the Air Division, Department of Environmental Quality, PO Box 1105, Richmond VA 23218 from August 13 to October 13, 2015. Please provide your full name, address and telephone number.

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- Proposed federal plan and model rule for existing power plants. This rule is open for public comment; follow EPA's instructions in the preamble to the rule.

You can learn more about these rules at EPA's website: <http://www2.epa.gov/carbon-pollution-standards>.

Virginia information: DEQ has established a web page with information about Virginia's actions for meeting the federal requirements: <http://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx>. This page will be updated periodically as new information and opportunities for public participation become available.

Exhibit C

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

AT RICHMOND, JUNE 2, 2010

CLERK'S OFFICE

APPLICATION OF

2010 JUN -2 P 3:27

APPALACHIAN POWER COMPANY

CASE NO. PUE-2009-00102
DOCUMENT CONTROL

For approval pursuant to Va. Code § 56-585.2
of purchase power agreements as part of its
participation in the Virginia renewable energy
portfolio standard program

ORDER DENYING APPLICATION

On September 18, 2009, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") an application pursuant to § 56-585.2 of the Code of Virginia ("Code") for approval of purchase power agreements ("PPAs") as part of its participation in the Virginia renewable energy portfolio standard ("RPS") program ("Application"). Specifically, the Application involves three PPAs under which the Company "will purchase energy: two for the Grand Ridge wind project (collectively, 'Grand Ridge') and one for the Beech Ridge wind project ('Beech Ridge')." ¹ The Company has contracted for 100.5 MW from Beech Ridge and 100.5 MW from Grand Ridge in the PPAs, or a combined 201 MW of nameplate capacity. ²

The Company requested that the Commission: (1) "find the Grand Ridge and Beech Ridge PPAs to be reasonable and prudent as part of [APCo's] participation in the [RPS program], as established by § 56-585.2 of the Code ... and as approved by the Commission in Case No. PUE-2008-00003;" and (2) "find that the Company has a reasonable expectation of achieving 12 percent of its base year electric energy sales from renewable energy sources during

¹ Application at 3.

² See, e.g., Application, Direct Testimony of Scott C. Weaver at 8 and Sched. 1.

calendar year 2022, and 15 percent of its base year electric energy sales from renewable energy sources during calendar year 2025."³

On October 7, 2009, the Commission issued an Order for Notice and Comment that established a procedural schedule for this matter.

On October 23 and November 20, 2009, respectively, the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel") filed a notice of participation and filed comments. Consumer Counsel stated as follows: (1) "Consumer Counsel cannot support inclusion of the three Beech Ridge and Grand Ridge contracts as part of [APCo's] RPS plan without additional information on [APCo's renewable energy certificate ('REC')] valuation and [American Electric Power Company Pool ('AEP Pool')] capacity credits for ownership of new wind purchased power agreements;" (2) "[b]ecause the three proposed contracts would allow [APCo] to meet all RPS goals, any additional renewable energy proposed by [APCo] in the future would not be needed to achieve those goals and thus should not be evaluated under the RPS statute;" (3) "Consumer Counsel proposes that, if these three contracts are approved, all future renewable energy should be evaluated to determine whether it is the least cost option;" and (4) "Consumer Counsel remains concerned with a plan that fails to minimize customer costs by selling excess RECs, an issue that the Commission will be able to address in future cost recovery proceedings."⁴

On November 20, 2009, the Old Dominion Committee for Fair Utility Rates ("Committee") filed a notice of participation and comments. The Committee stated as follows: (1) "[t]he Commission should not approve the two PPAs unless APCo demonstrates that its

³ Application at 4-5.

⁴ Consumer Counsel's November 20, 2009 Comments at 8.

revenue requirements will be lower with the PPAs than with alternative supplies over the planning horizon;" (2) APCo "states that the Cumulative Present Worth (CPW) of variable and incremental fixed (generation) costs of the AEP-East resource plan that includes the Beech Ridge PPA would be *\$153 million higher* over the full 27-year (2009-2035) study period, versus a resource plan that would not have included that PPA;" (3) "[s]imilar' results apparently were calculated with respect to Grand Ridge PPAs;" and (4) "APCo's participation in the RPS program is voluntary[, and its] customers should not bear a greater rate burden than necessary in order for APCo to participate in the program."⁵

On December 4, 2009, APCo filed a response to the comments of Consumer Counsel and the Committee. The Company stated as follows: (1) "[t]he Commission has before it sufficient information to make the required finding that the [Beech Ridge and Grand Ridge PPAs ('Wind PPAs')] are reasonable and prudent;" (2) "[t]he Wind PPAs have a minimal impact on the rates the customers pay, and that impact will decrease over the planning horizon;" (3) APCo "is not required to demonstrate that its revenue requirements with the Wind PPAs are less than its revenue requirements without the Wind PPAs;" (4) "[t]he RECs relied on by the Company for its comparative resource planning analysis are legal and appropriate;" (5) "[t]he Application demonstrates that the allocation of wind resources is equitable, reasonable and aligned with the achievement of the RPS Goals;" and (6) "[t]he Company's planned treatment of RECs is not relevant for this proceeding."⁶

On December 18, 2009, the Commission's Staff ("Staff") filed a report in this matter ("Staff Report"). Staff stated as follows: (1) "Staff cannot recommend approval of the

⁵ Committee's November 20, 2009 Comments at 3 (emphasis in original) (citations omitted).

⁶ APCo's December 4, 2009 Comments at 1-9 (typeface modified).

Company's [A]pplication at this time;" (2) "[i]n Staff's opinion, APCo has not met its burden of proof that it has a reasonable expectation of *reasonably* and *prudently* achieving the RPS Goals;" (3) "[t]he Company did not explore the purchase of low cost Tier II RECs as an option for meeting the RPS Goals [and it] appears to Staff that meeting the RPS Goals by purchasing Tier II RECs would likely be a lower cost alternative;" (4) "[t]he Company did not perform any analyses of constructing, owning, and operating 201 MW of wind and/or biomass generation facilities;" and (5) "Staff cannot evaluate whether the dual objectives of meeting the RPS Goals and obtaining 201 MW of generation capacity are best met through the proposed PPAs, other renewable resources, or through the Company developing its own renewable facilities."⁷

On December 29, 2009, APCo filed a Motion to Strike certain portions of the Staff Report "on the grounds that such portions do not comply with the terms of the Order [for Notice and Comment] as they are comprised of commentary and analysis that are far beyond the scope of, and thus irrelevant to, the Application."⁸ On January 20, 2010, Staff filed a response and requested that the Commission deny the Motion to Strike. On February 3, 2010, the Company filed a reply and requested that the Commission grant the Motion to Strike.

On January 8, 2010, APCo filed a Response to Staff Report. The Company stated as follows: (1) "[t]he components of the RPS Plan remain reasonable and prudent;" (2) "[t]he Company is not required to compare the costs of participation [in the RPS program] with those of non-participation;" (3) "[t]he Company is not required to compare the costs of construction with the costs of the Wind PPAs;" (4) "Staff presented no evidence in its Report to rebut the evidence presented by the Company in its Application of the reasonable cost and prudent

⁷ Staff Report at 14 (emphasis in original).

⁸ Motion to Strike at 1.

procurement of the Wind PPAs [nor] did Staff present any evidence that justifies the denial of the relief requested in the Application;" and (5) "[t]he Company's evidence clearly supports the Commission's determination that the Wind PPAs are reasonable and prudent components of [APCo's] previously-approved participation in the RPS Program and finding that [APCo] has a reasonable expectation of achieving the RPS Goals."⁹

On February 3, 2010, APCo filed a Motion to Supplement Response to Staff Report, which requested "that the Commission permit it to supplement its response to Staff's Report with new information regarding the Beech Ridge Wind Farm."¹⁰ On February 16, 2010, the Commission issued an Order Granting Motion to Supplement Response to Staff Report.

On February 26, 2010, the Commission issued an Order Denying Motion, which denied APCo's December 29, 2009 Motion to Strike certain portions of the Staff Report. In addition, that Order: (1) noted that no participant in this case has requested a hearing, and, thus, the Commission will rely upon the filed documents as the basis of our final decision in this matter; and (2) granted APCo leave to amend its response to the Staff Report to address the portions thereof that it sought to strike.

On March 15, 2010, APCo filed a Supplemental Response to Staff Report. The Company asserted that: (1) "Staff has presented no evidence to rebut that presented by the Company in its Application of the reasonable cost and prudent procurement of the Wind PPAs;" (2) "[n]or does the entire [Staff] Report contain any evidence that justifies the denial of the relief requested in this Application;" (3) "[i]nstead, the evidence in the Record clearly supports the Commission's determination that the Wind PPAs are reasonable and prudent components of

⁹ APCo's January 8, 2010 Response to Staff Report at 4-12 (typeface modified).

¹⁰ Motion to Supplement Response to Staff Report at 3.

[APCo's] previously-approved participation in the RPS Program and its finding that Appalachian has a reasonable expectation of achieving the RPS Goals."¹¹

On March 15, 2010, APCo filed a Motion to Supplement the Record, which requested "that the Commission permit it to supplement the record in this proceeding with the Amendments to the Beech Ridge Power Purchase Agreement."¹² No participant objected to, and we herein grant, such motion.¹³

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.

Code of Virginia

Section 56-585.2 of the Code states in part as follows:

B. Any investor-owned incumbent electric utility may apply to the Commission for approval to participate in a renewable energy portfolio standard program, as defined in this section. The Commission shall approve such application if the applicant demonstrates that it has a reasonable expectation of achieving 12 percent of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15 percent of its base year electric energy sales from renewable energy sources during calendar year 2025, as provided in subsection D.

...

F. A utility participating in such program shall apply towards meeting its RPS Goals any renewable energy from existing renewable energy sources owned by the participating utility or purchased as allowed by contract at no additional cost to customers to the extent feasible. A utility participating in such program shall not apply towards meeting its RPS Goals renewable energy certificates attributable to any renewable energy generated at a renewable energy generation source in operation as of July 1, 2007, that is operated by a person that is

¹¹ APCo's March 15, 2010 Supplemental Response to Staff Report at 5.

¹² Motion to Supplement the Record at 3.

¹³ These amendments, including the slight downward adjustment on prices prior to Beech Ridge obtaining an Incidental Take Permit from the U.S. Fish and Wildlife Service, do not change our analysis below.

served within a utility's large industrial rate class and that is served at primary or transmission voltage. A participating utility shall be required to fulfill any remaining deficit needed to fulfill its RPS Goals from new renewable energy supplies at reasonable cost and in a prudent manner to be determined by the Commission at the time of approval of any application made pursuant to subsection B.

This statute requires the Commission to determine whether the Beech Ridge and Grand Ridge PPAs fulfill the RPS Goals "at reasonable cost and in a prudent manner."¹⁴

Specifically, § 56-585.2 F of the Code first requires APCo to "apply towards meeting its RPS Goals any renewable energy from existing renewable energy sources owned by the participating utility or purchased as allowed by contract at no additional cost to customers to the extent feasible." Second, if additional energy supplies are needed to meet the voluntary RPS Goals, § 56-585.2 F of the Code requires APCo "to fulfill any remaining deficit needed to fulfill its RPS Goals from new renewable energy supplies at reasonable cost and in a prudent manner to be determined by the Commission at the time of approval of any application made pursuant to subsection B." In this regard, we find that the Beech Ridge and Grand Ridge PPAs do not fulfill the remaining deficit at a reasonable cost and in a prudent manner.

Beech Ridge and Grand Ridge PPAs

In this proceeding, the Company has asked the Commission to "find the Grand Ridge and Beech Ridge PPAs to be reasonable and prudent as part of [APCo's] participation in the [RPS program]...."¹⁵ Thus, APCo has the burden to prove that the Beech Ridge and Grand Ridge PPAs, under § 56-585.2 F of the Code, "fulfill any remaining deficit needed to fulfill its RPS

¹⁴ Va. Code § 56-585.2 F.

¹⁵ Application at 4.

Goals ... at reasonable cost and in a prudent manner." We find that the Company has not met this burden.

The General Assembly has set forth a policy in § 56-585.2 of the Code of encouraging the development of renewable energy through voluntary RPS programs, and the Commission has previously approved APCo's voluntary RPS program (Case No. PUE-2008-00003). As we noted in APCo's most recent fuel case, however, the General Assembly has made it clear that while renewable forms of energy are to be encouraged, the ratepayers of Virginia must be protected from costs for renewable energy that are unreasonably high.¹⁶ The General Assembly has also required that ratepayers be protected from renewable energy that is obtained in an imprudent manner. In other words, the General Assembly could – but has not – set forth a policy of encouraging renewable energy at *any* price or under *any* set of circumstances, no matter how burdensome the impact on consumers. This legislative policy is embodied in the "reasonable" and "prudent" mandates in § 56-585.2 F of the Code. As a result, although some renewable resources may satisfy the statutory standards, other or additional such resources may not when considering relevant cost, economic, and other factors.

In this regard, the Company does not assert that the Beech Ridge and Grand Ridge PPAs are needed in order to provide reliable service to its customers. The Company's testimony illustrates that its generation resource base plan, which does not include the Beech Ridge and Grand Ridge PPAs, produces a lower cost than a plan that includes these PPAs – *i.e.*, these PPAs

¹⁶ *Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6*, Case No. PUE-2009-00038, Order Establishing Fuel Factor at 9-10 (Aug. 3, 2009). The Commission further found that "the high cost for these two projects [does not meet] the standards in Va. Code § 56-249.6" and, accordingly, disallowed costs associated with the Beech Ridge and Grand Ridge PPAs – which reduced the requested fuel rate increase by approximately \$14.4 million. *Id.* at 10-11.

would not be part of an optimal cost resource plan.¹⁷ Rather, the Company (i) explains that it serves its customers "in concert with that of the other AEP-East Operating Companies under the auspices of the AEP Pool," and (ii) suggests that such service could take place with, or without, the Beech Ridge and Grand Ridge PPAs.¹⁸ Accordingly, APCo acknowledges that these PPAs result in increased costs to ratepayers.¹⁹

Specifically, APCo estimates that the Beech Ridge and Grand Ridge PPAs will increase the generation-related revenue requirement – above what it otherwise would be – by more than \$200 million over the life of the agreements.²⁰ That is, the Company's own projections conclude that these PPAs will increase revenue requirements by more than \$200 million on a net present value basis, and we question whether some of the assumptions that produced this estimate may be unwarranted, leading to a more realistic higher estimate of revenue impact. We find that these PPAs are not needed in order for the Company to provide reliable service to its customers at just and reasonable rates. We further conclude that the increase in Virginia jurisdictional revenue requirement is not reasonable at this time and for purposes of this proceeding.

Moreover, the Company's \$200 million estimate does not reflect the actual incremental nominal amounts paid by consumers since this estimate represents a discounted value. In effect, based on APCo's projection, the Company is asking ratepayers to borrow money for the PPAs today and to pay it back, with interest, over the life of the PPAs. APCo also reduces its projected cost impact on ratepayers by including a specific monetary estimate of avoided CO₂ costs

¹⁷ See, e.g., Application, Direct Testimony of Scott C. Weaver at Scheds. 1-2; Staff Report at 9-10.

¹⁸ See Application, Direct Testimony of Scott C. Weaver at 7-9 and Scheds. 1-2.

¹⁹ *Id.*

²⁰ See, e.g., *id.* at 8 and Sched. 1; Staff Report at 9-10. This estimate is for the AEP System East Zone. The Company also estimates the Virginia jurisdictional net cost increase for the first several years of the PPA. See, e.g., Application, Direct Testimony of Scott C. Weaver at Sched. 2.

beginning in 2015.²¹ We do not give this assumption significant weight based on the record here. Furthermore, we reject APCo's assertion that the increased cost represented by the Beech Ridge and Grand Ridge PPAs is necessarily mitigated by the cost of RECs that the Company would otherwise purchase absent these PPAs.²² In sum, we also find that APCo's estimate of the customer impact resulting from the Beech Ridge and Grand Ridge PPAs is understated.

More importantly, we are not evaluating the Beech Ridge and Grand Ridge PPAs under the same factual circumstances as presented in Case No. PUE-2008-00003.²³ APCo's rates have increased by more than \$500 million – or more than 50% for residential customers – since the beginning of 2007,²⁴ and this amount does not include the Company's currently pending base rate proceeding.²⁵ We also note that several of APCo's rate increases since 2006 have included recovery of environmental-related costs that, as with the cost of renewables, are expended with the goal of achieving positive environmental benefits.²⁶ Rate impact on customers is a key statutory factor in the Commission's consideration of energy supply proposals, whether they be new generation projects, fuel costs, or RPS measures.²⁷ Section 56-585.2 of the Code does not

²¹ See, e.g., Application, Direct Testimony of Scott C. Weaver at Sched. 2.

²² See, e.g., *id.* APCo also has not established that its estimated REC cost is reasonable, nor whether it reflects the purchase of lower cost Tier II RECs. See, e.g., Staff Report at 9-10.

²³ We also reject APCo's suggestion that these PPAs are "very comparable" to the prior two wind contracts approved by the Commission in Case No. PUE-2008-00003. See Application, Direct Testimony of Scott C. Weaver at 8. Simply put, the Company has not shown that the costs of the Beech Ridge and Grand Ridge PPAs are of the same magnitude as the costs of the wind PPAs in the prior case.

²⁴ See, e.g., Case Nos. PUE-2009-00039, PUE-2009-00031, PUE-2009-00038, PUE-2008-00045, PUE-2008-00046, PUE-2008-00067, PUE-2007-00069, PUE-2007-00067, and PUE-2006-00100.

²⁵ Case No. PUE-2009-00030.

²⁶ See, e.g., Case Nos. PUE-2009-00039, PUE-2008-00045, PUE-2007-00069, and PUE-2005-00056.

²⁷ Our analysis of "reasonable" and "prudent" under § 56-585.2 F of the Code may also be informed by other ratemaking statutes designed to protect the public, including §§ 56-235 and 56-249.6 of the Code. Among other things, § 56-235 of the Code requires rates to be just and reasonable, and § 56-249.6 of the Code prohibits utilities

create a limitless authority for a utility to increase customer costs, and we find under the instant circumstances that it is neither reasonable nor prudent for the Company to incur the increased cost associated with entering into the Beech Ridge and Grand Ridge PPAs.

Furthermore, as a result of the Commission's approval of the Company's prior two wind contracts, APCo is at a different stage in its progress towards meeting its voluntary RPS Goals – which extend to 2025 – than it was in Case No. PUE-2008-00003. The Company's evidence shows that these PPAs are not needed at this time to achieve those goals under the timeframe reflected in the statute.²⁸ Specifically, the voluntary goals in § 56-585.2 D of the Code extend to 2025 and include as follows: "RPS Goal IV: For calendar years 2023 and 2024, inclusive, an average of 12 percent of total electric energy sold in the base year, and in calendar year 2025, 15 percent of total electric energy sold in the base year." As explained by Staff, however, "[t]he addition of [Beech Ridge and Grand Ridge] to APCo's other wind power PPAs will allow the Company to meet all of its RPS Goals."²⁹ Similarly, Consumer Counsel states that "[i]f the Commission approves the proposed Beech Ridge and Grand Ridge contracts, the Company will have enough renewable generation to meet all Virginia RPS goals, which extend through 2025."³⁰ Indeed, the Company further acknowledges that, based on its projections, the addition of these PPAs will not only exceed the voluntary RPS Goals, but that, even by 2025, APCo will have more renewable energy credits than needed to meet such goals.³¹ We find that entering into

from incurring unreasonable fuel costs. Moreover, the potential rate impact and the context thereof may also be part of the analysis.

²⁸ See, e.g., Application, Direct Testimony of Scott C. Weaver at Sched. 3.

²⁹ Staff Report at 9.

³⁰ Consumer Counsel's November 20, 2009 Comments at 4 (footnote omitted).

³¹ See, e.g., Application, Direct Testimony of Scott C. Weaver at Sched. 3.

the Beech Ridge and Grand Ridge PPAs – under these circumstances and at this time – does not satisfy the statutory requirement to fulfill the remaining deficit in a prudent manner.³²

Moreover, APCo's evaluation herein incorrectly assumes that it *must* fulfill the voluntary RPS Goals under the statute. Rather, as noted above, § 56-585.2 of the Code neither requires – nor permits – the Company to fulfill its remaining RPS deficit at any cost and in any manner. The determination of what is reasonable and prudent under the statute must be made on a case-by-case basis with the filing of each such request and will be dependent upon the specific circumstances attendant thereto. For example, even if a utility shows that the cost of its proposed renewable resource is low when compared to other high cost renewable resources, the statute does not require the Commission to find that such cost is reasonable or that it is prudent for a utility to take actions incurring such cost.³³ In this case, we find that it was not prudent for APCo to enter into the Beech Ridge and Grand Ridge PPAs and to incur the cost associated therewith for providing service to its customers.

Finally, we do not, by this Order, indicate that wind power cannot be part of a portfolio of energy sources to serve customers. Indeed, as already noted, the Commission has approved other wind contracts for APCo. Here, however, the new proposals would exacerbate an already difficult rate environment for customers without significant offsetting benefits and, furthermore, are not needed at this time to meet voluntary RPS goals under the statute. The General

³² In addition, any estimated cost advantage of these PPAs, when compared against projected costs of renewable resources well into the future, are unreasonably speculative and, nonetheless, do not warrant the increased expenditures requested herein at this time.

³³ The Company also has not established that lower cost alternatives do not reasonably exist for its asserted purposes herein. For example, as explained by Staff: (1) "[t]he Company did not explore the purchase of low cost Tier II RECs as an option for meeting the RPS Goals;" and (2) "the Company did not perform any analyses of constructing, owning, and operating 201 MW of wind and/or biomass generation facilities." Staff Report at 14. Staff states that there are two tiers of RECs (Tier I and Tier II), and that Tier II RECs typically cost less than Tier I RECs. *Id.* at 10-12.

Assembly has enacted laws that make it clear that rate impacts are, and must remain, a key determinant in evaluating proposed projects, whether of renewable or non-renewable resources.

Accordingly, IT IS HEREBY ORDERED THAT:

- (1) The Company's March 15, 2010 Motion to Supplement the Record is granted.
- (2) The Company's Application is denied.
- (3) This case is dismissed.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: James R. Bacha, Esquire, and Charles E. Bayless, Esquire, American Electric Power Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215; Richard D. Gary, Esquire, and Noelle J. Coates, Esquire, Hunton & Williams LLP, 951 East Byrd Street, Richmond, Virginia 23219; C. Meade Browder, Jr., Senior Assistant Attorney General, Division of Consumer Counsel, Office of Attorney General, 900 East Main Street, 2nd Floor, Richmond, Virginia 23219; Anthony Gambardella, Esquire, Woods Rogers P.L.C., 823 East Main Street, Suite 1200, Richmond, Virginia 23219; Edward L. Petrini, Esquire, Christian & Barton, L.L.P., 909 East Main Street, Suite 1200, Richmond, Virginia 23219-3095; and a copy shall be delivered to the Commission's Office of General Counsel and Division of Energy Regulation.

A True Copy
Teste:


Clerk of the
State Corporation Commission

ATTACHMENT E
TO
MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE

Declaration of Kim Greene (Oct. 13, 2015)

1. I am the Chief Operating Officer (“COO”) of Southern Company. As COO, among other duties, I oversee generation, transmission, engineering and construction services, wholesale energy, fuels, and system planning at Southern Company. I hold a Bachelor’s Degree in Engineering Science and Mechanics from the University of Tennessee, a Master’s Degree in Biomedical Engineering from the University of Alabama at Birmingham, and a Master’s in Business Administration from Samford University. I began with the Southern Company system in 1991 as a Mechanical Engineer. I served in various roles, throughout the Southern Company system, as well as at Tennessee Valley Authority and Mirant, before I returned as the Chief Executive Officer of Southern Company Services, Inc. beginning in April 2013. I served in that capacity until I began my current position as COO on March 1, 2014.
2. In this declaration, I identify numerous impacts to the Southern Company system and its customers if we are required to undertake the steps the Environmental Protection Agency (“EPA”) itself has forecasted in its Regulatory Impact Analysis of the Clean Power Plan. Based

on EPA's Integrated Planning Model ("IPM") analysis, the impacts to the Southern Company system and its operating companies include:

- The premature shuttering of over 9,000 megawatts ("MW") of fossil fuel-fired units, constituting approximately 20% of the Southern Company system's generating capacity, with more than 8,000 MW retired in 2016 alone;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of approximately \$2 billion in 2016-2017;
- The undertaking of thirty-five independent transmission projects to ensure reliability, totaling approximately \$1 billion, with costs in 2016-2017 of over \$185 million; and
- Costs in 2016-2017 of \$950 million to compensate for impacts to the fuels program.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, the Southern Company system and its operating companies would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* <http://www3.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf>. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Southern Company is the leading energy supplier in the Southeastern United States, delivering 4.5 million customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, including fossil, nuclear, solar, and hydro-electric generating

plants. Southern Company's subsidiaries include four vertically integrated, regulated electric utilities—Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. As the COO, I and my staff are charged with ensuring the reliability and cost-effectiveness of our generation and transmission services.

5. Southern Company is obligated and committed to delivering safe, reliable, and affordable electricity to its customers. As a result, we have and apply tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process.

6. Southern Company has a planning horizon of forty years. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

7. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final

Rule” or “Clean Power Plan”). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), available at <http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf>.

8. I hereby rely on the information provided in the declarations of Jim P. Heilbron, John L. Pemberton, Michael L. Burroughs, and R. Allen Reaves, Jr., on behalf of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, respectively. Additionally, Southern Company Services, Inc., as agent for its operating companies, has reviewed and analyzed EPA’s Final Rule and EPA’s related impact assessment and associated modeling. The declarations on behalf of the aforementioned companies rely on such analysis.

9. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

SUMMARY OF EPA’S CLEAN POWER PLAN

10. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. EPA’s Final Rule is the most complex and far-reaching environmental regulation the utility industry has ever faced. Based upon my considerable experience in the utility industry, the Clean Power Plan would increase electricity prices to customers while jeopardizing reliability. The Final Rule will result in a complete restructuring of the nation’s electric sector and negatively impact America’s energy security.

11. The Final Rule requires, starting with enforceable targets in 2022, that utilities be on track to reduce CO₂ emissions 32% from 2005 levels by 2030 on a national basis—an extremely aggressive objective that, standing alone, would require years of lead time to achieve. However, the EPA expects utilities to take steps that will achieve 80% to 90% of that goal *before* the compliance period even begins in 2022. EPA readily admits that “achieving reductions by 2022”

will require “actions and investments that *yield* CO₂ emission reductions *prior to 2022*.” Final Rule at 42 (emphasis added).

12. The Final Rule establishes interim and final national “performance rates” for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO₂/MWh and 832 lbs CO₂/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO₂/MWh and 771 lbs CO₂/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state’s 2012 generation mix. States are told to adopt an “emissions standards” plan that either applies the performance rates to affected units or applies other rate- or mass-based standards to affected units that individually, or in the aggregate, achieve EPA’s goals upon implementation. States may alternatively adopt a “state measures” plan that includes, at least in part, measures imposed on entities other than existing electric generating units, as well as a backstop of federally enforceable standards for individual power plants that are triggered if the state measures do not achieve the required emission reductions.

13. The states have the obligation to plan for compliance, but the burden is on the owners and operators of affected units to comply with EPA’s Final Rule. Existing units cannot meet the new performance rates through any adequately demonstrated technological or operational changes at the unit. The reason the Final Rule is so different from any previous environmental regulation is that there are no demonstrated “control technologies” that will achieve the standards. Instead, in order to comply, utilities must curtail their generation, shutter plants, shift generation to lower-emitting resources, produce less electricity, and/or purchase credits or allowances under a trading

program that has not yet been created. This regulation of the utility system, which effectively mandates the replacement of one type of power generation with a different type of power generation, is unprecedented.

14. It is plain that, in light of the scope and stated purpose of EPA's Clean Power Plan, the rule will have unprecedented consequences for the Southern Company system and its customers, because "it will do more than just regulate—it will change markets." Gina McCarthy, Administrator, Env'tl. Prot. Agency, Remarks on U.S. Climate Action at the American Center (Aug. 26, 2015). Moreover, although some of the dates in the Final Rule may seem far off, as discussed above, our planning process and horizon makes it patently clear that many of these consequences will begin to occur immediately. EPA itself has forecasted the consequences to the Southern Company system and other utilities as part of its RIA. Specifically, using the IPM developed by ICF International, EPA has identified a "compliance solution," i.e., the unit-level retirements, shifts in generation, and specific new generation that define EPA's "least cost way to achieve the state goals" RIA at ES-4. Based on EPA's compliance solution, we were able to determine some of the immediate and significant impacts to our system's generation fleet and transmission system, including (1) inadequate reserve margins, (2) the need for transmission reliability projects, and (3) costs of changing fuel procurement.

EPA'S REGULATORY IMPACT ANALYSIS

15. Predicting the impacts on the electricity sector of a significant new regulatory program (such as the Clean Power Plan) requires sophisticated computer modeling. Due to the significant changes in the Final Rule from the Proposed Rule, EPA's own analysis and modeling of the Final Rule is the best current predictor of its impacts and effects. EPA's results can be used to assess what individual companies would have to do in order to comply with the Clean Power Plan now. Of course, states and individual utilities are working to make their own assessments

under existing state regulatory processes. However, given that EPA has justified the rule based on this modeling analysis, it must be considered while states and utilities begin to evaluate future actions.

16. IPM is a multi-regional, deterministic, and dynamic linear programming model developed by ICF Consulting. EPA asserts that it employs IPM to “examine air pollution control policies” and “project power sector behavior under future business-as-usual conditions” throughout the contiguous United States. *Id.* at 3-1.

17. EPA uses the IPM to perform most of the compliance cost, emissions, economic, and energy impact analyses for the Final Rule. *Id.* EPA’s analysis included using IPM “to project likely future electricity market conditions” both “with and without the Clean Power Plan Final Rule.” *Id.*

18. EPA has used IPM “extensively” for “over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective and final environmental policies.” *Id.* at 3-2, 3-4. EPA has used IPM to evaluate the impacts of: the Clean Air Interstate Rule; the Cross-State Air Pollution Rule; the Mercury and Air Toxics Standards; the proposed Carbon Pollution Standards for New Power Plants; the Disposal of Coal Combustion Residuals from Electric Utilities Guidelines; the Steam Electric Effluent Limitation Guidelines; and the Cooling Water Intakes Rule. *Id.* at 3-4.

19. The IPM platform EPA used to analyze the Final Rule is version 5.15, which was updated in August 2015. *Id.* at 3-5. EPA declares that version 5.15 was carefully updated from the version used to analyze the Proposed Rule to produce EPA’s “best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt.” *Id.* at 3-11. The updates consisted of

routine calibrations with the Energy Information Agency's (EIA) Annual Energy Outlook (AEO), including updating the electric demand forecast consistent with the AEO 2015 and an update to natural gas supply. Additional updates, based on the most up-to-date information and/or public comments received by the EPA, include unit-level specifications (e.g., pollution control configurations), planned power plant construction and closures, and updated cost and performance for onshore wind and utility-scale solar technologies. This IPM modeling platform incorporates federal and most state laws and regulations whose provisions were either in effect or enacted and clearly delineated in March 2015. This update also includes two non-air federal rules affecting EGUS Additionally, all new capacity projected by the model is compliant with Clean Air Act 111(b) standards, including the final standards of performance for GHG emissions from new sources.

Id. at 3-5. These nuanced updates support the Agency's view that "[t]he model is designed to reflect electricity markets as accurately as possible," subject, of course, to the accuracy of the model's inputs. *Id.* at 3-2.

20. EPA avows that IPM is a "state-of-the-art, peer-reviewed, dynamic linear programming model" used to estimate outcomes of pollution-abating policies, *id.* at 3-1, and thus would appear to be carefully monitored to ensure it forecasts the compliance solution for the Final Rule "as accurately as possible." EPA, Technical Support Document: Resource Adequacy and Reliability Analysis 2-3 (Aug. 2015).

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

21. EPA's compliance solution identifies almost 80,000 MW of fossil-fired steam electric generating units that will retire nationally by 2016. Of that, Southern Company must retire over 8,000 MW of fossil fuel-fired units.

22. As reflected by the declarations of Jim P. Heilbron, John L. Pemberton, Mike L. Burroughs, and R. Allen Reaves, these impacts affect each of our operating companies and its customers. Based on EPA's compliance solution, we have determined some of the immediate and irreparable consequences of these premature retirements for the Southern Company system as a whole. Even if the retirements identified by EPA in its compliance solution did not occur

until 2022 (the first year of the interim compliance periods), many of the actions identified below would still need to begin in 2016-2017 and would have significant costs in order to minimize the impacts on the cost-effectiveness and reliability of delivering electric service.

23. It is important to note that EPA's compliance solution includes prescriptive levels of demand side energy efficiency that are not adequately demonstrated in the states comprising our service territory. EPA "hard-coded" into the model an annual incremental demand reduction rate rising to 1.0% of electricity demand for each state. RIA at 3-13. In contrast, the states in which the Southern Company system serves achieved incremental demand reduction rates of 0.07% to 0.27% in 2012. Because EPA's "hard-coded" levels are not likely to be achieved, fossil fuel-fired sources will carry an even greater burden of compliance under the Final Rule, which will amplify the costs and reliability impacts described below.

Impacts to Reserve Margins

24. The retirements shown in EPA's compliance solution reflect Southern Company system retirements of over 8,000 MW in 2016 (and over 9,000 MW in total). While each operating company has its own obligation to meet customer needs, the operating companies' generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

25. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term

reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

26. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed to maintain reliable service to the system (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

27. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

28. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One industry measure of sufficient generating resources is to avoid having more than one customer electricity service interruption over a ten-year period. The Southern Company system currently has sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

29. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to our retail and wholesale customers from such higher production costs and unserved energy would be approximately \$2 billion during the 2016-2017 time period.

30. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be \$158 million of expenditures in 2016-2017.

Impacts to Transmission

31. A preliminary screening analysis was performed to assess the impacts to the transmission system, including needed transmission projects and estimated costs, due to the unit retirements identified in EPA's compliance solution. The preliminary screening analysis was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission

analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

32. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because the Southern Company system would not be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in the Southern Company system's service territory to maintain compliance with NERC Reliability Standards. Specifically, and as identified in the declarations of Messrs. Heilbron, Pemberton, Borroughs, and Reaves, we have determined that at least thirty-five additional transmission projects to Southern Company's transmission system at a cost of approximately \$1 billion dollars will be required. Such transmission projects include significant enhancements to the existing transmission system as well as nine new line and substation projects. The expenditure required in 2016-2017 to support these projects is in excess of \$185 million. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement

dates identified in EPA's compliance solution. The new line and substation projects will require from five to eight years to complete, and projects at existing lines and substations will take approximately one to five years to complete. As a result, there will be increased risk to system reliability until these projects can be completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

33. Even if the retirements identified by EPA for 2016 did not occur until 2022, when compliance targets set by the Clean Power Plan become effective, many of the actions identified above would not only still be necessary but would also still need to begin in 2016-2017 in order to minimize the reliability impacts of delivering electric service. Specifically, to accommodate those retirements, the Southern Company system would still have to begin the transmission projects that require five years or longer to complete, and the expenditure to support those projects would be in excess of \$87 million in 2016-2017.

Impacts from Fuel Contracts and Inventories

34. Under EPA's compliance solution, our operating companies will incur costs of approximately \$950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. These costs result from the closures that EPA has identified in the compliance solution. Specifically, we assessed: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring units' coal inventories (planned burn). Once contracts

are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to the Southern Company System from Fuel Contracts and Inventories

Fuel Costs	Estimated Cost in 2016-2017 (\$2015)
Coal Commodity Agreements	\$325M
Coal Transportation Agreements	\$415M
Additional Fuel Related Impacts	\$110M
Gas Firm Transportation Cancellations	\$40M
Coal Planned Burn	\$60M
Total \$	\$950M

Conclusion

35. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on the Southern Company system and its customers. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve the system's electricity needs for many years.

36. Direct impacts to the Southern Company system in excess of \$1.1 billion in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

37. The retirements identified in EPA's compliance solution would also negatively affect our customers by increasing their cost for electricity and risking reliability. The economic impact to

customers from higher production costs and unserved energy would be approximately \$2 billion in 2016-2017.

38. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, the Southern Company system would be required to take action and incur approximately \$245 million in costs in 2016-2017 to ensure the operating companies continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Kim Greene", is written over a horizontal line.

Kim Greene
Southern Company, Chief Operating Officer

October 13, 2015

ATTACHMENT F
TO
MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE

Declaration of John Voyles (Oct. 20, 2015)

DECLARATION OF JOHN N. VOYLES, JR.

I, John N. Voyles, Jr., declare that the following statements made by me are true and accurate to the best of my knowledge, information, and belief:

1. I am the Vice President, Transmission and Generation Services of LG&E and KU Energy LLC ("LKE").

2. LKE is the parent of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), public utilities owning and operating approximately 8,000 megawatts of coal-fired and natural gas fired assets in Kentucky that form the backbone to provide electricity to their 941,000 customers.

2. All of LG&E's and KU's coal-fired and natural gas-fired electric generating units ("EGUs") are regulated under EPA's Clean Power Plan.

4. Under the Clean Power Plan, the Commonwealth of Kentucky likely will not have an approved plan to implement the emission guidelines until September 2019. LG&E and KU must begin complying with the Clean Power Plan on January 1, 2022. This means there will be less than three years between the time when LG&E and KU know exactly what their regulatory requirements will be and when they must begin complying with those regulatory requirements.

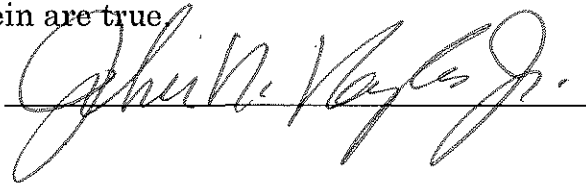
5. The Clean Power Plan requires a massive national shift in generation away from coal-fired sources toward gas and renewables. New EGUs, with the requisite electric transmission interconnects, require many years to develop, permit, obtain regulatory approval and construct. Substituting either natural gas-fired or renewable generation for reduced coal-fired generation requires intensive planning, permitting and regulatory approval processes. LG&E and KU has invested

substantially in its existing EGU fleet, retrofitting them with hundreds of millions of dollars of pollution controls that have not yet been fully depreciated, including some of which are still under construction to meet other EPA regulatory requirements.

6. LG&E and KU have a legal obligation to serve customers, and their operations are regulated by the Kentucky Public Service Commission ("PSC"), which must approve infrastructure decisions such as early retirement of generating units, construction of new generating units and construction of electric transmission. These approvals involve lengthy public proceedings, often taking several years to complete.

7. The Clean Power Plan will cause irreparable harm to LG&E and KU by forcing them to take action to comply with the rule well before their precise regulatory obligations are known with certainty. There simply is not enough time between when state plans are approved and the compliance period begins to wait to make decisions regarding compliance. Because the rule envisions utilities will substantially shift the sources of their generation, and because retiring existing generation and building new generation takes many years, LG&E and KU have started the process to decide which EGUs they may have to retire early, and what type of generation they must build to replace that retired capacity. LG&E and KU are currently expending resources to model the options available to them in the absence of "perfect information" regarding their ultimate precise compliance obligations.

I make this Declaration under penalty of perjury pursuant to 28 U.S.C. § 1746, and I state that the facts set forth herein are true

A handwritten signature in dark ink, appearing to read "John N. Vagstad Jr.", is written over a horizontal line.

Dated: October 20, 2015

ATTACHMENT G
TO
MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE

Declaration of Derrick Brummett (Oct. 14, 2015)

**IN THE UNITED STATES COURT OF APPEALS FOR
THE DISTRICT OF COLUMBIA CIRCUIT**

NATIONAL RURAL ELECTRIC
COOPERATIVE ASSOCIATION, *et al.*

Petitioners,

v.

UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY,

Respondent.

No. _____

**DECLARATION OF DERRICK BRUMMETT OF SAN MIGUEL
ELECTRIC COOPERATIVE, INC. IN SUPPORT OF MOTION TO STAY**

I, Derrick Brummett, declare:

1. My name is Derrick Brummett. I am the Interim General Manager for San Miguel Electric Cooperative, Inc. ("San Miguel" or the Cooperative"). Except where specifically noted below, I have personal knowledge of the facts contained in this declaration, and to the best of my knowledge, they are true and correct.

2. In my capacity as Interim General Manager for San Miguel, I am responsible for general oversight of the Cooperative to ensure fulfillment of San Miguel's mission statement "to maintain a dependable power supply at the lowest possible and competitive cost to our customers through integrity, hard work, and safety." This encompasses the overall day-to-day maintenance of the economic

and technical profile of the Cooperative including plant performance, reliability, fuel sufficiency, and financial integrity. The manager is put in place and is overseen by the San Miguel Board of Directors. The San Miguel Board is made up of 26 Directors who represent San Miguel's two Wholesale Power Customers, Brazos Electric Power Cooperative (BEPC), and South Texas Electric Cooperative (STEC), and their respective distribution cooperatives.

3. I began my career with San Miguel as a Senior Accountant in 2007, assuming supervision of the Accounting Department and all of its functions in 2008. In 2010, I was promoted to the senior management position of Administrative Services Manager, reporting directly to the General Manager. In August 2014, I was appointed, by the San Miguel Board, to serve as the Cooperative's Interim General Manager after the retirement of its prior General Manager. I received my BA in Accounting from Friends University in Wichita, Kansas.

San Miguel Electric Cooperative

4. San Miguel was created on February 17, 1977, for the purpose of owning and operating a 400-MW mine-mouth, lignite coal-fired generating plant and associated lignite coal-mining facilities.¹ San Miguel is a not-for-profit electric

¹ A "mine-mouth" power plant is one that is located "at the mouth of a mine," *e.g.*, adjacent to a mine. "Lignite" is a recognized rank of coal that is distinct from other ranks of coal such as "bituminous," "sub-bituminous," and "anthracite." For

cooperative, small business entity, incorporated in the State of Texas under the Electric Cooperative Corporation Act, Tex. Util. Code, Chapter 161. San Miguel exists for the purpose of owning and operating the generating plant and associated lignite coal-mining facilities. San Miguel is owned and democratically governed by its members through its Board of Directors, which are elected by, and come from, its membership.

5. San Miguel produces a net 391 MW of affordable, reliable electricity for its 26 member cooperatives—enough electricity to power approximately 200,000 rural Texas homes.

6. Construction of San Miguel's plant was initiated as a joint venture by STEC and BEPC, both of which are generation and transmission cooperatives (G&T's). San Miguel assumed financial responsibility for the construction of the plant and related mining facilities upon receiving long-term financing from the Federal Financing Bank (FFB) guaranteed by the Rural Electrification Agency (REA) (predecessor to the Rural Utility Service (RUS)), a division of the US Department of Agriculture, and commercial operation of the plant began on January 7, 1982. This project was developed in the context of the Congressional enactment of the Powerplant and Industrial Fuel Use Act of 1978, which functionally outlawed the use of natural gas to generate electricity. It is my

purposes of this declaration and clarity, I refer to "lignite coal" when referring to the rank of coal being mined and utilized by San Miguel.

understanding that energy shortages in the early 1970s and other related circumstances that led to the passage of the Fuel Use Act significantly contributed to the decision to build a lignite-fired power plant at San Miguel.

7. STEC and BEPC have entered into Wholesale Power Contracts with San Miguel that cannot be terminated before the year 2037 (but which can be extended), under which they have agreed to purchase San Miguel's entire output. Other than its Wholesale Power Contracts with STEC and BEPC and some transmission revenues, San Miguel has no other sources of revenue. Thus, as discussed below, running the plant to produce electric power is the only effective means available to San Miguel to generate revenue to pay down its outstanding obligations described in detail below.

South Texas Electric Cooperative and Brazos Electric Power Cooperative

8. The Wholesale Power Contracts that San Miguel has with STEC and BEPC provide that STEC and BEPC are collectively responsible for San Miguel's total cost of owning and operating the plant, including San Miguel's debt service obligations, and such responsibility is allocated between STEC and BEPC by reference to their respective power purchase obligations for any given year. The members of STEC and BEPC are distribution electric cooperatives. Each cooperative member of STEC and BEPC are also members of San Miguel.

9. STEC is a 1,316 MW G&T cooperative whose members' service territory extends across 44 counties throughout South Texas. STEC's members, all of whom are members of San Miguel, are eight south Texas electric distribution cooperatives: Jackson Electric Cooperative, Inc. (Edna, Texas), Karnes Electric Cooperative, Inc. (Karnes City, Texas), Magic Valley Electric Cooperative, Inc. (Mercedes, Texas), Medina Electric Cooperative, Inc. (Hondo, Texas), Nueces Electric Cooperative, Inc. (Robstown, Texas), San Patricio Electric Cooperative, Inc. (Sinton, Texas), Victoria Electric Cooperative, Inc. (Victoria, Texas), and Wharton County Electric Cooperative, Inc. (El Campo, Texas).

10. Established in 1944, STEC's headquarters facility is located at the Sam Rayburn Power Plant Complex on the Guadalupe River just outside Nursery, Texas, an unincorporated community in Victoria County, Texas. Power generation, transmission line and substation service facilities are also located in Pearsall, Texas (population 9,618) and substation service facilities are located in Donna, Texas (population 16,270).

11. The power STEC provides to its members is generated from multiple energy sources, including wind, lignite, natural gas, diesel fuel, and hydroelectric. San Miguel is one of STEC's primary generation sources.

12. BEPC is a 3,763 megawatt G&T cooperative whose members' service territory extends across 68 counties from the North Texas panhandle to South

Texas. All of BEPC's 16 electric cooperative members are also members of San Miguel. Established in 1941, BEPC is based in Waco, Texas and is the state's oldest and largest G&T cooperative.

13. The Boards of Directors for San Miguel, BEPC, and STEC have all approved an agreement between the three cooperatives to the effect that, on January 1, 2016, STEC will assume all of BEPC's rights and obligations under its Wholesale Power Contract with San Miguel, leaving only STEC and its distribution cooperatives as members of San Miguel. The RUS has been apprised of this agreement, and its approval of the transaction is pending. At the effective date, STEC and its members will be the sole parties affected by any impacts associated with the 111(d) Rule (defined in paragraph 16 below).

San Miguel has 22 years of remaining operational life and no plans to retire.

14. The engineered life of San Miguel's power plant, on which the Wholesale Power Contracts with BEPC and STEC are based, has recently been re-confirmed as 2037, 22 years from now. Despite repeated misconceptions by EPA in its modeling, San Miguel will not retire as result of market conditions, the Cross-State Air Pollution Rule (CSAPR), or the Mercury and Air Toxics Standards (MATS). As discussed below, San Miguel has heavily invested in environmental controls to ensure that the unit can comply with these and other pending rules and

live out its engineered life through 2037 and only the 111(d) Rule would force the premature closure of San Miguel.

San Miguel has made significant investments in environmental controls to comply with other EPA rules

15. San Miguel has invested approximately \$130 million in environmental controls, including the control and monitoring of emissions of:

- Sulfur Dioxide (SO₂): flue gas desulfurization, a/k/a “scrubbers” and related infrastructure;
- Nitrogen Oxide (NO_x): low NO_x burners, over-fire air, a neural network and other combustion practice improvements, and selective-non-catalytic reduction (known as SNCR);
- Mercury (Hg): oxidation/capture enhancement systems that leave Hg chemically bound;
- Particulate matter (PM): electrostatic precipitator and ash handling systems; and
- Coal Combustion Product (CCP): recycling for mine, highway, construction, and aerospace applications.

These investments have positioned the unit to fully comply with all applicable state and federal permitting and regulatory requirements. This includes CSAPR, MATS, and pending EPA actions relating to regional haze.

EPA's 111(d) Rule

16. The United States Environmental Protection Agency's "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" ("111(d) Rule" or "Rule") requires a 32-percent reduction by 2030 of carbon dioxide ("CO₂") emissions from 2005 levels. The Rule purports to achieve those reductions, in part, by imposing CO₂ emissions standards on coal-fired power plants like San Miguel. EPA admits, however, that existing coal-fired power plants like San Miguel cannot meet these performance standards through any technological or operation changes at the unit. Unlike previous air quality rules like CSAPR and MATS, discussed above, there is no commercially available, viable technology that could enable San Miguel to meet or even approach the emission standard of 1,305 pounds per net megawatt hour set by the final 111(d) Rule for existing coal-fired power plants like San Miguel. Instead, San Miguel must curtail production (or close entirely) and/or purchase emission credits or allowances under a CO₂ emissions trading program that does not yet exist. What follows is a description of why the conditions created by the 111(d) Rule will force the retirement of the unit and result in immediate and irreparable harm to San Miguel, its members, its employees, and its surrounding community.

Forced, premature retirement of San Miguel's power plant and mine

17. Under any measure or timeframe evaluated, San Miguel's average CO₂ emission rate is significantly higher than the 1,305 pounds per net megawatt hour set by the final 111(d) Rule for existing coal-fired power plants like San Miguel. For the period 2010 through 2012, for example, San Miguel's average CO₂ emission rate was 2,451.5 pounds per net megawatt hour. The only way I could envision San Miguel meeting the 111(d) emission rate would be to run less, buy credits, or some combination of both – factors that lead to my conclusion described below that the unit will not survive 111(d) Rule implementation.

18. Although it is far from clear whether, and to what extent, a rate-based or mass-based market regime will be imposed in Texas and on San Miguel, the foundation of any market will be the above-referenced categorical standard of 1,305 pounds per net megawatt hour set by the final 111(d) Rule for existing coal-fired power plants. As a result, because San Miguel's emissions are so far above the categorical standard set by EPA, San Miguel's unit will be dramatically disadvantaged in the marketplace and it will not be able to be dispatched anywhere near its historic capacity factor. "Capacity factor" is the ratio of a power plant's actual output over time divided by its potential output if it were able to operate at full capacity all the time. If the plant is run less, the capacity factor is decreased. If the capacity factor decreases, the fixed costs of operating the power plant will be distributed over fewer megawatts of electricity generated. The plant will become