WRITTEN TESTIMONY OF CHARLES PATTON

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BEFORE THE U.S. SENATE

ENVIRONMENT AND PUBLIC WORKS COMMITTEE

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Chairman Capito, thank you for inviting me here today. I appreciate this opportunity to offer the views of the Appalachian Power Company (APCo) on the carbon dioxide (CO2) rules for existing power plants (the "Clean Power Plan") that have been proposed by the U.S. Environmental Protection Agency (EPA). My name is Charles Patton, and I am the President and Chief Operating Officer of Appalachian Power Company (APCo). Headquartered in Charleston, West Virginia, APCo serves 960,500 retail customers in West Virginia and Virginia. The parent company of APCo is American Electric Power (AEP). Based in Columbus, Ohio, AEP, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states, and will be directly affected by the requirements of the final rule. AEP companies also own the nation's largest electricity transmission system, a nearly 40,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Generation Resources, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

AEP's generating fleet employs diverse fuel sources – including coal, nuclear, hydroelectric, natural gas, oil, and wind power**.** Due to the location of our service area and the historic importance of coal to the economies of our states, approximately 60 percent of our current generating capacity uses coal to generate electricity. My testimony provides the perspectives of both AEP and APCo on the proposed GHG rules, and offers both the national and the West Virginia impacts of these rules.

AEP believes strongly in the merits of fuel diversity in generating electricity. This is a key issue in the topic of this hearing on the impact of 111(b) and 111(d) on energy production and electricity generation. Today, coal-fueled power plants account for approximately 60 percent of AEP's generating capacity, while natural gas represents 23 percent and nuclear 5 percent. The remaining capacity comes from wind, hydro, pumped storage and other sources, including energy efficiency. By 2026, we project that our coal-fueled generating capacity will drop to 45 percent, while natural gas capacity will increase to 33 percent.

WEST VIRGINIA IMPACTS OF CLEAN POWER PLAN

In 2013, coal provided 95% of West Virginia's electricity[1] and is responsible for 89,000 direct and indirect jobs within the state.[2] However, the proposed Clean Power Plan (CPP) would likely result in substantial reductions in coal-fired generation and coal-related jobs by requiring an 8% reduction in the state's CO2 emission rate by 2020 and a 20% reduction by 2030.[3] These required emission cuts would force West Virginian's to switch to more expensive energy sources, which come at a substantial cost premium to existing low-cost coal-fired generation. The over 400,000 low-income and middle-income families in West Virginia, representing 59% of the state's households, already spend 20% of their after-tax income on energy. Modeling by NERA Economic Consulting projects that the CPP will cause a 12% increase in electricity prices for West Virginia consumers, with a peak year increase of 14%. Under another scenario (what would happen if West Virginia consumers do not significantly reduce their electricity use), electricity prices in West Virginia could increase by 28%, with a peak year increase of 21%.[4]

These added costs come at a time where West Virginia is already making substantial progress in reducing its CO2 emissions, largely through the announced retirement of 18 coal units totaling 2,237 MW. However, through the building block approach utilized by EPA in developing the CPP, West Virginia is assumed to bear the burden of additional significant reductions without appropriate credit for committed coal retirements. In fact, West Virginia's

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[1] U.S. Energy Information Administration, *Electric Power Monthly*, February 2014.
[2] National Mining Association, http://www.countoncoal.org/states/.
[3] http://www2.epa.gov/sites/production/files/2014-06/20140602-state-data-summary.xlsx & http://www2.epa.gov/sites/production/files/2014-05/documents/20140602tsd-goal-computation.pdf.
[4] NERA Economic Consulting, *Potential Impacts of the EPA Clean Power Plan*.

remaining coal EGUs, (after the announced retirements), would have the lowest average CO2 emission rate for coal units in the US, 2,048 lbs CO2/net electricity MWh, according to the West Virginia Department of Environmental Protection.

EPA's building block formula assumes West Virginia would be able to decrease average coal plant heat rates by 6%, increase renewable energy output by 700% and cut customer demand by 10% through energy efficiency by 10% by 2030.[5] As AEP and WV DEP and many others have noted in their comments to EPA, there are significant problems with how these figures were developed and calculated as well as errors in the data used. This in turn has meant that EPA has substantially overstated the amount of reductions in CO2 that can be achieved thru its Building Blocks. As a result, EPA is ultimately requiring new and dramatic changes in the energy supply mix when the electric utility industry is still coming to grips with the dramatic loss of a substantial amount of base load coal capacity that has supported the grid over many decades.

U.S. EPA's own analysis of the proposed guidelines predicts that 46,000 to 49,000 megawatts of coal-fueled generation will be shut down no later than 2020 as a result of this proposal.[6] That's in addition to approximately 71,000 megawatts of coal-fueled generation that EPA concludes has retired or will retire between 2010 and 2016. This means about one-third of all existing coal-fueled power plants, enough generation to power 60 million homes, would be gone in just five years. EPA estimates that most of these combined retirements (about 120,000 megawatts) occur by 2016. The additional retirements will happen at plants that have made, or

[5] EPA, GHG Abatement Measures Technical Support Document, June 2014.
[6] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, June 2014.

are just completing, significant environmental investments to comply with other EPA regulations. Closing this much generation in such a short timeframe raises serious concerns about the ability to maintain reliability and meet peak demand, particularly in periods of extreme weather. Higher-cost replacement generation will need to be built and significant investment in transmission and other mitigation will be necessary to maintain the reliability of the electricity grid – all of which will take time and ultimately, will increase the cost of electricity.

The proposed state emission rate requirements were calculated by U.S. EPA assuming that natural gas combined cycle plants will run 70 percent of the time, far above current operating levels in most states, which is unrealistic. Most existing natural gas plants were not designed, built or permitted to run at those levels. And, in many areas, the natural gas pipeline infrastructure does not exist to support those levels of operation. The U.S. fleet of natural gas combined cycle power plants has never averaged a 70 percent capacity factor. Even in 2012, when natural gas prices were very low, the natural gas combined cycle fleet only achieved a 51 percent annual capacity factor. Significantly higher use of natural gas for electricity generation will increase natural gas prices and result in higher electricity costs and higher home heating costs in many states. It also will increase overall energy costs in the United States. This is highly problematic because in the past several years low natural gas prices have been providing important support for a still tenuous U.S. economy.

The ultimate impacts to AEP customers and WV as whole will largely depend upon the structure and stringency of the final rule and the path laid forward for compliance within West Virginia's State Implementation Plan. However, based on the proposed rule, AEP has serious concerns with the potential cost and reliability implications of this proposal. AEP has submitted substantial comments outlining concerns and errors within the rule to EPA in an effort to help protect WV ratepayers and WV jobs.

IMPORTANCE OF FUEL DIVERSITY TO COAL AND WEST VIRGINIA

The combination of recent regulations related to clean air; the 111(b) rule on new units; and the 111(d) rule on existing units will have a severe impact on fuel diversity. It is appropriate, therefore, to begin with a summary of why fuel diversity has been, and must continue to be, one of the central objectives of energy policy in the United States. Coal, including coal mined in West Virginia, has played a central role in this policy for the last century.

The importance of fuel diversity cannot be overstated given its implications for assuring economic and energy security. Too great a reliance upon any one energy source (particularly those with a history of price volatility) creates a significant risk exposure to electricity price escalation and supply disruptions. As has been proven repeatedly across the globe, such exposure can lead to severe impacts on the supply and price of electricity for residential, commercial, and industrial customers.

For example, the relatively recent nuclear catastrophe in Japan serves as a sobering reminder of what can happen if a single energy source is abruptly removed from use. In 2011, an earthquake and tsunami devastated shoreline communities and seriously damaged the Fukushima Daiichi nuclear power plant. Resultant radiation leaks and a greatly eroded public faith in safety of nuclear power led to the shutting down of all of Japan's 48 nuclear reactors for mandatory maintenance and safety checks. To date, no units are back in service, though several have finally received preliminary approval to restart sometime this year.[7] Heavily populated areas of the country have faced the realities of rolling blackouts, while manufacturing facilities had to reduce output, with some making moves to relocate abroad. Meanwhile, natural gas prices in Japan nearly tripled as power producers scrambled to fill the massive void left in their energy infrastructure.

Domestic energy disruptions and their consequences are clearly evident by such disasters as Hurricane Katrina in 2005, where nine oil refineries were shut down for an extended period of time and 30 oil platforms were either damaged or completely destroyed, dramatically hampering oil and gas production. United States natural gas prices spiked following the disaster and for months afterward remained more than double the price over the previous year.

There is another unique feature to coal that must be considered from an energy security perspective. Coal is a solid and physically stable energy resource that can be safely stockpiled at the power plant site. A typical power plant takes advantage of this feature by keeping an inventory of 30 to 60 days of supply of coal at the plant site. This is an incredibly valuable characteristic when considering the risks associated with supply interruptions of other fuels, such as natural gas. If storms, natural disasters, or other forces interrupt major gas pipeline infrastructure, gas-fired power plants immediately cease to produce electricity and cannot resume production until infrastructure repairs are made. Coal plants, on the other hand, can continue to operate if the major fuel supply is compromised. Similarly, nuclear power enjoys

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[7] http://dw.de/p/1Eo0X

the benefit of large reserves of fuel capacity on the plant site. This is a factor of fundamental value to any energy security solution and has national security benefits as well – particularly given the abundant reserves of coal in the United States.

AEP has a long history of using a variety of fuels within its generation mix and has increasingly has sought to diversify its resources. AEP's leadership and innovation in our core generation, transmission and distribution services have led to improvements in efficient and clean production and delivery of our product. We accomplished these improvements through continual advances in generation technology efficiency, improved environmental performance, reduced transmission line losses, implementation of energy audits, support of improvements in the efficiency of end-use appliances and fixtures, and improved delivery of real-time pricing and usage information for the electric grid. This innovation has helped insulate our customers from fluctuations in the cost of electricity, reduced overall costs and diversified the ways we provide service to our customers.

Much of AEP's eastern service territory, due to its proximity to Appalachian coal, has typically been served by coal-fired generation. These large coal reserves have served AEP's customers well, resulting in some of the lowest costs for electricity in the country and fueling economic expansion. However, the advent of nuclear power allowed AEP to begin to diversify away from coal in the 1970's and further diversification occurred in the 2000's with natural gas combined cycle generating facilities being added to the system, in addition to purchases of wind power, due in large part to government tax incentives. Over the past twelve years AEP has added more than 5,000MW of natural gas fuel diversity, which has enabled our company to switch between fuel sources based on price fluctuations of fuels over time.

REGULATORY BARRIERS TO FUEL DIVERSITY

There are numerous barriers to fuel diversity within the electric generation fleet; however our most pressing concerns are the new federal environmental regulations and the lack of an energy policy promoting diversity and therefore energy security. As an example, the proposed CO_2 NSPS for new sources effectively prohibits the construction of new coal-fired facilities unless CCS is included – and unproven and extraordinarily expensive technology. These proposed CO_2 performance standards come in the wake of other new environmental regulations, most notably the Mercury and Air Toxics Standards. Due to these new EPA rules and other factors, electric utilities have already publicly announced their plans to shut down or convert 462 coal-fired generating units, totaling about 72,000 MW.[8] This represents over 20 percent of the U.S. coal fleet will be shut down within the next few years. Due to these regulations, our nation's electric grid will become increasing reliant on natural gas for new generation capacity, likely eliminating both diversity and flexibility in new power plant builds. Federal policy should support fuel diversity, not preclude it.

FUEL DIVERSITY UNDERMINED BY GHG RULE FOR NEW PLANTS

In addition to the concerns related to the Clean Power Plan, which are proposed New Source Performance Standards (NSPS) for <u>existing</u> electric generating units (EGUs) under section 111(d) of the Clean Air Act, AEP also has serious concerns with the proposed section 111(b) NSPS regulations which would apply to <u>new</u> EGUs. EPA initially proposed a 111(b) rule in

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[8] http://www.americaspower.org/sites/default/files/Coal%20Unit%20Retirements%20JANUARY%2025%202015.pdf

April 2012, but then subsequently withdrew the rule and re-proposed a new rule in September 2013. The rule sets separate standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units. While AEP supports the distinction between the unit types the proposed standard of 1,100 lb-CO_2/MWh for fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units is highly problematic.

The proposed 1,100 lb-CO_2/MWh standard was set by EPA based on a Best System of Emission Reduction (BSER) determination, which incorrectly found that CCS can be commercially used to control CO_2 emissions. AEP completely disagrees with EPA's determination, based in large part due to first-hand experience with a CCS demonstration project, within the state of West Virginia, at our Mountaineer unit. CCS technologies have not been adequately demonstrated and any objective analysis would prove this to be the case. Furthermore, even though EPA has proposed CCS as part of its BSER determination it fails to provide adequate or requirements for successful short term or permanent sequestration.

As proposed, the 111(b) rule as it would effectively preclude the use of coal in new generating units without carbon capture and storage (CCS). As CCS is not a commercially viable technology the proposed rule is setting de facto energy policy with respect to new electric generating units. Based on these concerns and others, AEP has requested that EPA once again withdraw the rule and re-proposed based on existing, proven technologies that result in lower CO_2 emission rates, not speculative ones such as CCS.

FUEL DIVERSITY UNDERMINED BY GHG RULE FOR EXISTING PLANTS

The proposed Clean Power Plan states that "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies." The facilities and equipment to which the proposed guidelines apply are capital-intensive, long lived assets, many of which have historically operated for 50 to 60 years. In addition, at most of these facilities, significant additional investments have recently been made to comply with other environmental regulations.

EPA has a statutory duty to "tak[e] into account the cost of achieving such reduction" when determining the "best system of emission reduction." The most centrally relevant costs are the costs to the existing sources required to make the emission reductions mandated under section 111(d). EPA has failed to identify, much less consider, those costs. Instead, EPA has estimated macroeconomic net costs to the entire nation. Under EPA's proposal, virtually all of the reductions in CO2 emissions from affected EGUs come from reduced utilization of coal-fired EGUs. EPA must, at a minimum, determine the diminution in asset value to the owners of those existing sources, and the local and regional economic disruption and unemployment that would result from the proposal.

However, for purposes of this rulemaking, EPA assumes that all existing coal-fired sources that will be operating in 2020 and beyond should gradually reduce their generation and be replaced by lower or non-emitting generation or EE measures over a fifteen-year period. The most egregious example of this scenario is in Arizona, where EPA's model predicts that all coal fueled EGUs will disappear before the final goals become effective in 2030. EPA projects that implementation of the proposed rule will result in significant changes in how and where electricity is generated. The agency estimates that as a result of implementing the proposed rule up to an additional 49 GW of existing coal-based generation will retire by 2020, that existing NGCC units will be utilized more, and that new renewable energy development and energy efficiency programs will be implemented.

As an example, under its assessment of its preferred 111(d) option, EPA projects that an incremental 41 to 44 GW of generation will be taken offline in 2016 relative to the Base Case. Many of the units projected to retire are currently in the process of making multi-million dollar investments in emission controls to comply with MATS. Such investments have been made due to programs like the MATS rule and the Regional Haze program "best available retrofit technology" or BART requirements. In analyzing the cost-effectiveness of controls under the BART guidelines, EPA has often used the "remaining useful life" of a source as an input to that analysis, and its default assumption is that existing sources will continue to operate for 20 years after completing the retrofit of such controls.

However, EPA's own models demonstrate that the integrated operation of the four building blocks would result in the retirement of many additional sources, none of which have reached the end of their "remaining useful life." EPA has therefore assumed billions of dollars of stranded investment associated with current retrofit projects and existing plant, property and equipment, which may not be fully depreciated. In regulated jurisdictions, these costs will be passed on to customers in the form of higher rates. In deregulated jurisdictions, these stranded investments will result in a loss of shareholder value. The magnitude of the recent investments in the existing fleet is staggering. AEP alone has spent approximately $3.5 billion to upgrade its existing units, and several compliance projects are still underway. Nowhere does EPA take into account the loss of these assets, and their potential impact on customer rates. Nor does EPA explain how it can override the discretion Congress specifically vested in the states to avoid such adverse economic impacts. EPA must address these costs, and revise its proposal to allow states the latitude to design programs that do not result in the confiscation of assets, or prematurely force retirements rather than preserving the remaining useful lives of these units.

BACKGROUND: OVERARCHING AND SERIOUS PROBLEMS WITH THE PROPOSED 111(d)

EPA states that the proposed Clean Power Plan ("CPP") is "*an important step toward achieving the GHG emission reductions needed to address the serious threat of climate change.*"[9] However, in taking that step, EPA has overstepped its statutory authority, and ignored the legal, technical, and practical limitations that govern the production, delivery, and use of electricity in the United States. Efforts have already been made, and continue to be made, by AEP and others to reduce greenhouse gas emissions from fossil-fueled electric generating units ("EGUs"). Additional dramatic changes in the nation's portfolio of generation resources and their associated emissions will continue in the near-term due a number of regulatory and market drivers. For example, implementation of the Mercury and Air Toxics Standards,[10] and Regional Haze requirements[11] will result in AEP alone permanently removing

[9] 79 Fed. Reg. 34,833.
[10] 40 CFR Part 63, Subpart UUUUU.

over 6,000 megawatts ("MW") of coal-fired generating capacity from service and converting an additional 730 MW from coal- to gas-firing. Others are taking similar steps. Yet EPA provides no comprehensive assessment of the emission reductions resulting from these actions in order to determine whether, and if so, how much more reduction can and should be achieved, consistent with the requirements of section 111 of the Clean Air Act.

In its fact sheet released with the CPP, EPA claimed that the proposal would result in a 30 percent reduction in CO_2 emissions from 2005 levels for the power sector by 2030.[12] However, based on the guidance released on November 13, 2014, the actual reduction in CO_2 emissions from the existing fossil fleet required by this proposal on a mass basis is 30 percent *from 2012 levels* by 2030.[13] For the AEP fleet, this means that the 20 percent reduction in emissions already achieved from 2005 levels is largely disregarded, and deep additional cuts will be required to satisfy the goals established by EPA.

There are a number of legal, technical, and practical concerns and uncertainties that make implementation of the proposed rule unworkable. Many of these unknowns relate to the assumptions underlying each building block, regulatory strategies that are unproven, levels of implementation that are technically and practically unachievable, or interactions that are not feasible to design or enforce within the existing statutory and regulatory authorities of the states.

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[11] 40 CFR §51.308.

[12] http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-overview.

[13] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice, Additional information regarding the translation of emission rate-based CO_2 goals to mass-based equivalents*, 79 Fed. Reg. 67,406 (November 13, 2014).

EPA acknowledges that some of these issues "introduce practical enforceability considerations under a state plan." But instead of fully evaluating these issues, EPA relies exclusively on the purported "flexibility" that the agency believes states have to address any challenges associated with implementation. This claimed "flexibility" is illusory. There is no way for states to assure that individual generating units will achieve the emission reductions associated with block 1, and no technical basis upon which EPA can conclude that the projected emission reductions will actually occur, because EPA does not evaluate the extent to which such measures have already been implemented, and did not properly account for the heat rate increases associated with recent control equipment installations. There is no way for states to control system dispatch decisions that are entrusted to regional authorities, and simply attempting to "freeze" emissions from designated facilities in 2020 based on projected emissions and generation that accommodate the effects EPA hopes to achieve through building blocks 1 and 2.

The proposed rule does not adequately account for the many factors that introduce variability into existing units' utilization and emissions, including weather patterns, unanticipated equipment problems, and changes in local load conditions. The output of renewable resources similarly is heavily influenced by weather conditions, equipment condition, and other factors that are neither controlled nor controllable by the designated facilities or the states, and EPA has misinterpreted existing state standards by ignoring the extent to which those standards are currently satisfied by participation in multi-state REC markets, the extent to which they are satisfied in whole or part through energy efficiency measures or alternative payments, and the extent to which they rely on unique resources whose status as “renewable” energy sources in any future section 111(d) plan is uncertain. These errors make EPA’s cumulative targets unreasonable and arbitrary.

Finally, EPA has no authority to regulate the behavior of consumers, and its simplistic evaluation of the potential for future energy efficiency measures ignores fundamental aspects of program design and achievability. There are errors in each and every one of the blocks upon which the state goal calculation is based that make the final result arbitrary and capricious. All of these errors inflate the prospects for future emission reductions, and simply shift the search for effective ways to meet the arbitrary goals from one building block to another and beyond, to measures EPA admits are not cost-effective, in a continuous loop of legally, technically, and practically flawed options that impairs the development of any workable compliance solution.

BACKGROUND: IMPACTS OF 111(d) ON TRANSMISSION & RELIABILITY

In addition, EPA has failed to identify and consider the costs of the proposed transformation of the existing electricity systems, such as additional transmission facilities, additional natural gas pipeline capacity, additional transmission support capacity, additional financing costs of intermittently used generating capacity, and additional maintenance, repair and replacement due to increased ramping up and down of dispatchable generation. It is implausible to interpret the mandate to consider cost in section 111(d) as excluding the costs pinpointed on specific existing sources and specific local and regional economic disruption and unemployment. EPA’s proposal is deficient and arbitrary in its omission of: 1) any analysis of the direct cost impacts to owners of existing coal-fired EGUs that would be expected or forced to shut down or reduce utilization; and 2) any analysis of the full costs of ensuring a reliable bulk power supply system in a rapid transition to lower carbon and intermittent electricity generation.The reliability and resource adequacy analysis performed by EPA is incomplete and inaccurate. It asks the wrong questions and provides answers developed using the wrong tools. Any analysis of the achievability of the CPP must be based on the tools used by reliability organizations to assess power flows under the conditions projected to occur as the CPP is implemented. Because EPA assumes that there will be dramatic changes in the composition, location, and characteristics of the generation fleet as a result of the CPP, such an analysis must be performed iteratively by organizations with the expertise and knowledge to analyze the dynamic nature of the impacts of these changes.

The North American Electric Reliability Corporation ("NERC") recently released a preliminary assessment of the stability and reliability of the grid if the changes envisioned in EPA's modeled outputs for its cost-benefit analysis actually occurred in 2020.[14] These changes will strain reliability and essential services, require expansion of the transmission grid, and are inconsistent with the planning horizons used to implement transmission reliability enhancements. The Southwest Power Pool ("SPP") has performed a similar analysis of the potential reliability impacts within the SPP region. SPP found that: "1) the CPP will impact the reliability of the bulk electric system; 2) the timing proposed by EPA for compliance is infeasible; and 3) the proposed CPP will have material impacts on the market-based dispatch of electric generating units within the SPP region."[15] AEP's own internal analysis of the SPP and

[14]http://www.nerc.com/pa/RAPA/ra/Reliaiblity%20Assessment%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf
[15] http://www.spp.org/publications/CPP %20Reliability%20Analysis%20Results%20Final%20Version.pdf

PJM regions within which it operates yielded similar results. Any future proposals must be accompanied by a comprehensive analysis that demonstrates that the security and reliability of the bulk power system will not be compromised.

The gap between the Clean Power Plan's initial deadlines and the earliest in-service dates possible for new infrastructure will create an atmosphere ripe for massive blackouts that would jeopardize the nation's economy and homeland security. Its timelines are so aggressive, we cannot hope to achieve the infrastructure development it will require. The reliability concerns promulgated by the Clean Power Plan stem from inadequate pipeline and electric generation and transmission infrastructure to achieve its goals, and inadequate time to plan for newly developed infrastructure. Failure to address these reliability issues will undermine the environmental goals of the EPA and simultaneously undermine the reliability of the nation's electric grid because that failure will result in band-aid responses that ultimately will result in sub-optimal solutions.

BACKGROUND: SUMMARY OF ISSUES WITH FOUR BUILDING BLOCKS OF 111(d)

EPA's Interpretation of "BSER" is Fatally Flawed

This proposal is wholly different from any prior emission limitation, standard, or guideline developed by EPA under the CAA. If adopted, the CPP would establish an expansive and unprecedented program to regulate the production, delivery, and use of electricity in the United States. The assumptions that EPA uses to develop state goals supersede the authority granted to the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, contain significant and fundamental technical flaws regarding the nature and operation of electricity generators and the electricity grid, and intrude upon authority reserved to the states. The proposal also is contrary to the express requirements of section 111 of the CAA, and EPA's own regulations, in several significant respects.

A fatal defect in EPA's CPP is the proposal's dependence upon an abstract, out-of-context interpretation of "system" in the phrase "best system of emission reduction" in the section 111 definition of "standard of performance." EPA's unprecedented interpretation of the word "system" in the "standard of performance" definition is disassociated from, and in conflict with, the interlinked CAA definitions of "stationary source," "existing source," "emission limitation," and "performance standard," and with the legislative history of Section 111. It is also in conflict with EPA's existing regulations that implement section 111, and at odds with EPA's interpretation and application of section 111 throughout its 44-year history. Rather than reflecting the degree of emission limitation achievable by applying a demonstrated technology-based (or work practice) system of emission reduction to the affected EGU, as the statute plainly directs, the proposal requires a reduction in the hours of operation and/or rate of production (or complete shutdown) of affected EGUs, a result contrary to the text and structure of the statute, and that could not have been imaginable to the Congresses that enacted and amended the CAA in 1970, 1977, and 1990.

Never before has EPA claimed the authority to limit productive capacity or control the rate of customer usage of a particular product, and the assertion of authority to do so here has no foundation in the CAA. Because EPA's interpretation would purport to give EPA broad power to regulate human behavior, EPA's interpretation of "system of emission reduction" must be rejected.

Building Block 1 Comments

EPA mischaracterizes observed variability in heat rate at coal units as being "evidence" that existing coal-based generating units are not being adequately operated or maintained.[16] Heat rate performance is influenced by a variety of known and unknown, controllable and uncontrollable factors, whose interaction is unit-specific and varies throughout the life of the unit. Moreover, EPA's examination of opportunities to improve heat rate either ignores or does not fully consider the following factors:

- the availability, technical viability, and economic feasibility of potential improvement opportunities at individual units;
- heat rate improvement measures that have already been implemented;
- unit-specific factors that influence the magnitude and sustainability of potential heat rate improvements; and
- other environmental regulatory requirements that may mask or eliminate opportunities for potential heat rate improvements.

There is also a long history of successful advancement and adaptation of new technologies, operating procedures, materials, and equipment upgrades that have allowed units within the existing fleet (both coal-fired and non-coal units) to maintain and improve efficiency through adoption of best practices. Had EPA fully considered these factors, the

[16] "GHG Abatement Measures TSD". U.S. EPA. June 10, 2014. p. 2-1

agency would have correctly concluded that both the proposed 6% and alternative 4% targets for heat rate improvements are overly aggressive, and cannot feasibly be implemented by the majority of existing coal-based generating units because:

- There is a wide range of inherent limitations on the potential for heat rate improvements, including original design, geographic location, availability of space, emission controls, and prior improvement efforts;
- Unit efficiency naturally degrades over time;
- There is no accurate method to measure heat rate in real time;
- Heat rate improvements may be masked by control technology installations or changes in duty cycle; and
- Remaining useful life will affect the economic feasibility of continued efficiency investments.

There is no single emission standard or limitation that is achievable or adequately demonstrated for all regulated sources. Instead, EPA should rely on Section 111(h)(1) of the CAA, which authorizes the Administrator to identify design, equipment, work practice, or operational standards, or a combination thereof, when it is not feasible to establish a standard of performance, and develop a work practice standard for EGUs. Such a standard would assure that cost-effective changes are routinely made at existing units, consistent with the criteria contained in section 111(d).

Building Block 2 Comments

Building block 2 is based on EPA's generalized assumption that *all* existing NGCC units can be redispatched to sustainably achieve a 70% capacity factor, and that the additional generation provided by the existing NGCC units will *exclusively* offset generation from other, higher-emitting, existing fossil-fueled units. The underlying analysis that supports this assumption relies on inaccurate data, and generally represents a poor understanding and application of the basic concepts and operating metrics used to assess historic and future unit performance. The result is an assumed level of performance that simply has not been adequately demonstrated to be achievable across the fleet of existing NGCC units.

Further, EPA fails to explain how this building block is consistent with section 310 of the Clean Air Act,[17] which specifically preserves the authority of all other federal agencies, when such requirements for "environmental dispatch" would effectively override the system of security constrained economic dispatch created by the Federal Energy Regulatory Commission ("FERC") and implemented through regional transmission organizations ("RTOs"), independent system operators, and other balancing authorities, as required by the Federal Power Act.[18]

Even if such a concept could be incorporated into a section 111(d) standard, the level of operation assumed by EPA in calculating the state goals contains fundamental errors, such as: (1) relying on nameplate capacity instead of net demonstrated capacity (which results in about a 10% increase in the goals that cannot reasonably be achieved); (2) including units that are not designated facilities; (3) failing to accurately and consistently account for units that operated

[17] 42 U.S.C. § 7610(a).
[18] 42 U.S.C. § 824(b).

for only a portion of 2012, or were not yet operating; and (4) failing to adequately evaluate the availability of gas pipeline capacity to deliver fuel and transmission capacity to deliver power, and the time and cost necessary to increase capacity if it is not already available. EPA's own policy case modeling does not achieve the level of operation assumed by EPA in calculating the state goals.

EPA must present a proposal that, at a minimum, is grounded in accurate, complete data and that reflects the actual operation of the electricity grid. Given the egregious nature and scope of concerns to be resolved in building block 2 *alone*, EPA should withdraw the current proposal and publish a new proposed rule for public comment.

<u>Building Block 3 Comments</u>

EPA has not cited, and AEP has not discovered, any statutory basis for the inclusion of generation from new and existing non-emitting nuclear and renewable resources in its calculation of state goals to regulate emissions of fossil-fueled EGUs. Such units are not "affected facilities" in the listed source categories for which these guidelines are proposed, nor would they be subject to any standards under section 111 if they were "new." EPA's expansion of its regulatory grasp far exceeds the scope specifically authorized by Congress, and invades the reserved powers of the States under the Tenth Amendment to the U.S. Constitution.

Moreover, EPA's use of individual state renewable portfolio standards to establish "regional goals" that each state must achieve is ill-informed, and overlooks distinctions among these state standards that either significantly reduce the absolute value of those standards, or rob the states of flexibility in implementing the goals, or both. EPA has also insufficiently evaluated the technical potential and cost of renewable resources across the states, and ignored significant questions related to the expansion of both intrastate and interstate transmission resources, regulatory processes, cost allocation, and timing.

Any goals established by EPA in the final rule cannot rely on nuclear or renewable resources. However, EPA should prescribe procedures for the development of state plans that allow states to determine if or how renewable resources may be included in their compliance plans.

Building Block 4 Comments

EPA also does not have clear authority from Congress to dictate energy policies that control customer demand, including the degree to which energy efficiency ("EE") measures should be adopted by individual customers.[19] Even if such authority existed, EPA has failed to demonstrate that the level of EE used to calculate the state goals is achievable or has been adequately demonstrated. Specifically, EPA ignores the expert evaluations of the majority of states regarding a reasonably achievable level of EE, the pace of increase in EE achievement, and a reasonable level of costs to achieve those proposed EE levels. Further, the data and methodology that the agency used in establishing these levels for all states in a one-size-fits-all manner ignores many fundamental differences between the states that affect the nature and

[19] Indeed, in the context of EPA's authority under Section 169 of the CAA to specify what is the "best available technology" for regulated pollutants in a new source review ("NSR") permit, the Supreme Court noted with approval that, "BACT may not be used to require 'reductions in a facility's demand for energy from the electric grid,'" and that "BACT should not require every conceivable change that could result in minor improvements in energy efficiency, such as the aforementioned light bulbs." Rather, the Court confirmed that BACT can only be required for pollutants that the source itself emits, and that permitting authorities should consider whether the proposed regulatory burden outweighs any emission reductions that can be achieved. *UARG v. EPA*, 134 S.Ct. 2427, 2448 (2014). These same principles should apply to the BSER, which is based on technology that can be applied to emissions from the regulated source, and must satisfy the statutory balancing of costs, other environmental affects, and the emission reductions actually achieved.

scope of achievable EE measures and rates of growth. EPA did not use a transparent process in estimating the costs of the proposed EE levels, did not consider all cost elements of EE, and did not give adequate consideration to the ways such costs will affect customers. EPA's failure to specifically identify the evaluation, measurement and validation ("EM&V") methods required for a satisfactory state plan, and its failure to assess whether such EM&V measures are currently applied in the programs identified as "best practice standards," provide an inadequate basis for commenters to determine the actual impact of the proposed guidelines. Accordingly, EPA should not assume specific levels of EE achievement in developing any state-specific goals, but states should retain the flexibility to determine if or how EE measures may be included in their compliance plans.

Implementation Concerns

The flaws identified within each of the building blocks collectively lead to serious concerns related to the practical implementation of the CPP. Because the errors identified in the development of each building block lead to a significant overstatement of its potential contribution to reductions in emissions from existing fossil-fueled EGUs, the combined whole represented in the state goals has not been adequately demonstrated and is not achievable. All flexibility that would have been present had EPA accurately assessed each building block evaporates.

Moreover, EPA's proposal to extend compliance responsibilities to entities other than the "designated facilities" exceeds EPA's and states' authorities under the CAA, creates uncertainty regarding the ultimate enforceability of the state goals, and raises procedural and substantive due process concerns for sources within the regulated source categories if states elect to follow EPA's advice and reduce their plan requirements to goals enforceable only against those sources. EPA has ignored the requirement under section 111(d) to provide states with the flexibility to adjust the stringency of the final performance standard or the timing of the ultimate compliance schedule based on the remaining useful life of the regulated sources. And the timeline to achieve compliance is unreasonable, particularly for building blocks 1 and 2, both of which are proposed to be fully implemented by 2020. EPA has no authority to dictate the timing of implementation or to establish interim goals, and these are issues that should be reserved to the states as they develop final performance standards.