American
Public Power
Association

2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4801

Ph: 202.467.2900
Fax: 202.467.2910
www.PublicPower.org

Comments of the American Public Power Association

On the

U.S. Environmental Protection Agency's

"Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations" Proposed Rule

80 Fed. Reg. 64,966 (October 23, 2015)

Docket ID No. EPA-HQ-OAR-2015-0199

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Joe Nipper, Sr. Vice President of Regulatory Affairs & Communication
Carolyn Slaughter, Environmental Policy, Director
Alex Hofmann, Energy & Environmental Services Director
Tanzina Islam, Energy & Environmental Manager

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II. Executive Summary

The American Public Power Association (APPA) appreciates the opportunity to provide comments on the Federal Plan Requirements and Model Trading Rules (together the Proposed Trading Plan Rule or Proposed Rule) proposed by the U.S. Environmental Protection Agency (EPA or Agency) on October 23, 2015, to implement EPA's Section 111(d) Rule. Given the design, timing, and requirements of the Section 111(d) Rule, appropriately finalizing these proposals is of great importance to improving the affordability and workability of the entire program.

While the final Section 111(d) Rule contained a number of positive changes reflecting some of the recommendations made by APPA and others, it still tries to do too much too fast for public power utilities and their customers in many states. In so doing, the final rule has a high potential for creating stranded costs and curtailing the remaining useful life of existing electric generating units (EGUs), increasing operating costs, unduly adding new costs for related infrastructure, and ultimately raising electricity bills for millions of consumers. Increases in some states could be as much as 30 percent according to recent studies.

Moreover, EPA has not adequately considered the costs added by wholesale energy and capacity markets administered by regional transmission organizations (RTOs), or the impediments to investment in new resources posed by these markets. Electricity costs to consumers continue to rise in every region of the country, but they are rising faster in regions where the wholesale markets are administered by RTOs.

APPA believes that the Section 111(d) Rule goes far beyond what is legally permissible under the Clean Air Act (CAA). Therefore, APPA has joined many others in seeking judicial review and a stay of the rule pending that review. For the same reasons, APPA also believes that the Proposed Trading Plan Rule exceeds the Agency's authority under the CAA. The proposals inappropriately intrude on federal, state, and local authority in numerous ways. These legal infirmities are outlined below. Thus, APPA's first recommendation is that EPA withdraws these proposals and issues new proposals consistent with EPA's authority. APPA recognizes, however, that EPA is defending the Section 111(d) Rule publicly, and in court, and so is unlikely to heed that recommendation.

Because the outcome of litigation is uncertain, the bulk of APPA's comments focus on a number of recommended changes to address the feasibility and key design elements of the Proposed Trading Plan Rule. Indeed, if the Section 111(d) Rule is sustained in the courts in whole or in part, the workability of the trading programs may be the only economic protection left for many consumers. Following are highlights of APPA's recommendations. With respect to the proposed Federal Plan, APPA recommends EPA:

- Adopt both rate-based and massed-based plans;

- Work with affected states to determine what constitutes remaining useful life of a facility on an EGU-specific basis, without determining in advance that the plan itself inherently protects an affected EGU's value;

- Establish a price safety valve;

- Include the reliability safety valve and modify it to: 1) allow it to operate for a longer time; and 2) clarify certain terms and the specific roles of reliability entities;

- Recognize renewable energy constructed after finalization of the Section 111(d) Rule;

- Allow energy efficiency projects and programs to qualify for generating credits under a rate-based plan;

- Modify the Clean Energy Incentive Program (CEIP) to allow all renewable, other non-emitting resources, and energy efficiency programs to qualify, and to make it a true incentive by not deducting the credits or allowances from a state budget;

- Allow states to submit a partial plan that determines the methodology for allocating allowances without being required to adopt the CEIP;

- Provide greater safeguards for smaller entities consistent with EPA's obligations under the Small Business Regulatory Fairness and Enforcement Act, including more time for compliance;

- Address the flaws in the Alternative Compliance Pathway and make it available in rate-based plans as well as mass-based plans; and

- Alleviate the conflict of interest that the New Source Review program creates for compliance with the Section 111(d) Rule.

With respect to the proposed Model Trading Rules, APPA recommends EPA:

- Ensure broad access to wide and deep emissions trading markets for affected entities;

- Establish mechanisms to guard against market manipulation;

- Make out-of-state renewable energy widely available for compliance. APPA agrees with EPA that renewable energy from a state with a mass-based plan can be used for compliance in a state with a rate-based plan;

- Establish a conversion factor to allow states that adopt a rate-based plan to trade compliance instruments with states that adopt a mass-base plan and vice versa;

- Include all forms of biomass as eligible and pre-approved renewable energy;

- Adopt a process for adding new qualifying renewable energy;

- Allow states to determine the methodology for allocating allowances to retired EGUs. If a state subject to a federal plan does not submit a partial plan to take control of allowances, EPA should consult with the state on the methodology for allocating allowances to retired EGUs;

- Allow unlimited banking and borrowing of emission rate credits or allowances;

- Ensure enforcement, monitoring and verification requirements for energy efficiency programs are not burdensome and that existing state and local requirements are incorporated;

- Eliminate the requirements for set-asides to address leakage in mass-based plans. EPA has failed to demonstrate that leakage will occur; and

- Defer to and acknowledge that states have discretion to modify the model rules.

APPA appreciates the continued willingness that EPA has shown to meet with APPA and its members since the time that the Section 111(d) Rule was issued. APPA stands ready to meet with the Agency to further discuss the recommendations set out in these comments, as well as other aspects of the Proposed Trading Plan Rule.

III. Introduction

The American Public Power Association (APPA) submits the following comments on the proposed rule of the U.S. Environmental Protection Agency (EPA or Agency) entitled, "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations," (Proposed Trading Plan Rule or Proposed Rule)[1]. APPA is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the U.S. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing

[1] 80 Fed. Reg. 64,966 (Oct. 23, 2015)

reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA. Collectively, public power utilities deliver electricity to one of every seven electricity consumers. We serve some of the nation's largest cities, including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. However, most public power utilities serve small communities of 10,000 people or less. APPA participates on behalf of its members collectively in EPA's rulemakings and other proceedings under the Clean Air Act (CAA or Act) that affect the interests of public power utilities.

The public power utilities that are members of APPA provide over 15 percent of all kilowatt-hour sales of electricity to consumers and do business in every state except Hawaii. All APPA utility members are Load Serving Entities (LSEs), with the primary goal of providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA utility members with the long-term interests of the residents and businesses in their communities. EPA's Proposed Trading Plan Rule has the potential to seriously disrupt the operations of APPA utility members and the electric power markets in which they operate, and could, if implemented, impose significant costs and regulatory burdens on APPA utility members. APPA therefore has a clear and significant interest in the outcome of the present

rulemaking, as well as other related rulemakings[2] that are part of the Agency's overall effort under the CAA to regulate carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions.

A. Section 111(d) of the CAA and EPA's Section 111(d) Rule.

EPA issued a final rule (Section 111(d) Rule) on August 3, 2015, promulgating CO_2 emission guidelines for existing coal- and natural gas-fired electric generating units (EGUs) pursuant to CAA Section 111(d). Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.[3] CAA Section 111(d) authorizes EPA to establish emission performance standards based on an evaluation of the "Best System of Emission Reduction" (BSER) that has been "adequately demonstrated" for categories of existing sources. The Section 111(d) Rule defines existing sources for purposes of EPA's Clean Power Plan as EGUs constructed on or before January 8, 2014. States are required to submit to EPA by September 6, 2016, a plan that either meets the performance standards described in the EGs or an interim plan that satisfies EPA's requirements for such plans. If an interim plan is filed, states must submit final plans to EPA by September 6, 2018. If a state's plan does not meet EPA's requirements, then EPA intends to promulgate a federal plan for that state. A general description of EPA's concept for a federal plan is one part of the present rulemaking.

The Proposed Trading Plan Rule consists of three parts. First, for states that do not submit an approvable plan, EPA proposes two potential federal plan concepts: a rate-based

[2] On December 1, 2014, APPA filed comments on the related proposed rule entitled, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,830 (June 18, 2014) ("111(d) Proposed Rule"). Comments of the American Public Power Association (APPA) on EPA's Section 111(d) Proposed Rule for Carbon Dioxide Emissions from Existing EGUs, Docket ID No. EPA-HQ-OAR-2013-0602-22871. APPA also filed comments on EPA's proposed rule, "Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,960 (June 18, 2014). APPA Comments on EPA's Section 111(b) Modified and Reconstructed EGUs, Docket ID. No. EPA-HQ-OAR-2013-0603-0150 (date filed?).

[3] 80 Fed. Reg. 64,662 (Oct. 23, 2015)

emission trading scheme and a mass-based emission trading scheme.[4] EPA states that when it promulgates federal plans for individual states, it intends to use a single approach, either the rate-based or mass-based plan.[5]

Second, EPA proposes model trading rules. Although states may develop and submit their own plans to implement the Section 111(d) Rule, EPA states in the Proposed Trading Plan Rule that a state plan adopting the model trading rules will be "presumptively approvable."[6] EPA also states that adopting the model trading rules will enable a state's EGUs to trade emission credits or allowances with EGUs subject to a federal plan—if the state adopts the same type of model trading rule (rate-based or mass-based) that EPA ultimately adopts as the federal plan.[7]

Third, and separate from the federal plan and model trading rules, the Proposed Rule amends EPA's 40 C.F.R. part 60, subpart B regulations addressing the procedures for submitting and promulgating state and federal plans.[8] These amended regulations would apply to implementation of the Section 111(d) Rule and any future rules promulgated under CAA Section 111(d).

B. Proceedings in This and Related Rulemakings.

EPA published its proposed Section 111(d) Rule on June 18, 2014.[9] APPA submitted comments on that proposal on December 1, 2014.[10] The Agency issued the final Section 111(d) Rule and the Proposed Trading Plan Rule on August 3, 2015, and formally published them both in the Federal Register on October 23, 2015. Twenty-seven states and numerous industry groups

[4] 80 Fed. Reg. at 64,966.
[5] *Id*. at 64,968.
[6] *Id*. at 64,969
[7] *Id*. at 64,969.
[8] *Id*. at 64,971.
[9] 79 Fed. Reg. 34,830
[10] See supra n.1

have filed more than fifteen separate petitions for review challenging the legality of the Section 111(d) Rule in the United States Court of Appeals for the District of Columbia Circuit.[11] APPA is a petitioner in those cases. [12] Although the Proposed Trading Plan Rule is not directly at issue in these court proceedings, the outcome of these challenges could also determine if the Proposed Rule is lawful or necessary.

IV. The Proposed Trading Plan Rule Is Legally Flawed and Should Be Withdrawn.

A. EPA's Proposed Trading Plan Rule Is Unlawful Because EPA's Final Section 111(d) Rule Is Unlawful.

EPA's Proposed Trading Plan Rule is unlawful because it implements the Agency's unlawful final Section 111(d) Rule. APPA submitted detailed comments explaining why EPA's proposed Section 111(d) Rule violated the CAA and other laws. In the preamble to the final Section 111(d) Rule, EPA has addressed some of APPA's concerns, dismissed some, and ignored others. But the final Section 111(d) Rule does not remedy the fundamental legal flaws in EPA's proposal. The final Section 111(d) Rule violates the requirements of the statute that EPA asserts authorizes it; establishes binding, but unachievable emission guidelines based on an impermissible interpretation of the statute; intrudes on the authority Congress reserved to state and local governments to regulate and provide for electric utility service; and assumes authority to regulate certain interstate aspects of the electric utility industry that Congress exclusively granted to the Federal Energy Regulatory Commission (FERC or Commission). Because the Proposed Trading Plan Rule would implement the unlawful Section 111(d) Rule, it extends all of the illegal aspects of the Section 111(d) Rule. APPA hereby incorporates by reference its

[11] See, e.g., State of W. Va. v. EPA, No. 15-1363 (D.C. Cir. filed Oct. 23, 2015)
[12] See Utility Air Regulatory Group and Am. Pub. Power Ass'n v. EPA, No. 15-1370 (D.C. Cir. filed Oct. 23, 2015

comments on the proposed 111(d) Rule and supplements those comments to address changes EPA made in the final Section 111(d) Rule.

1. EPA Lacks Authority to Regulate EGUs Under Section 111(d) Because It Is Already Regulating Them Under Section 112.

The Proposed Trading Plan Rule is unlawful because EPA lacks authority to regulate coal- and oil-fired EGUs under section 111(d). Section 111(d) prohibits EPA from adopting emission guidelines for existing sources from a source category when the Agency has regulated that source category under section 112.[13] EPA listed coal- and oil-fired EGUs as a source category under Section 112 in 2000, [14] and regulated emissions from those sources in 2012 under the Mercury and Air Toxics Standards.[15] Because coal- and oil-fired EGUs are already regulated under Section 112, EPA cannot regulate these EGUs under Section 111(d). For the same reasons, EPA lacks authority to implement the unlawful Section 111(d) Rule for states that do not submit an approvable state compliance plan, as proposed in the Proposed Trading Plan Rule.

2. The Proposed Trading Plan Rule's Standards of Performance Are Unachievable and Based on EPA's Impermissibly Defined "Best System of Emission Reduction."

The standards of performance in the Proposed Trading Plan Rule are unlawful because they cannot be achieved by individual sources and are based on the final Section 111(d) Rule's impermissible definition of BSER. Under Section 111, a standard of performance must "reflect[] the degree of emission limitation *achievable* through the application of the best *system of emission reduction*" that has been adequately demonstrated for sources in the regulated category.[16] The Proposed Trading Plan Rule "implements and enforces standards of performance for affected EGUs," that are "based on [EPA's] determination of the BSER for

[13] CAA § 111(d)(1)(A)(i).
[14] 65 Fed. Reg. 79,825 (Dec. 20, 2000),
[15] 77 Fed. Reg. 9304 (Feb. 16, 2012)
[16] CAA § 111(a)(1) (emphasis added).

existing sources of air pollution."[17] EPA's determination of BSER in the Section 111(d) Rule impermissibly relies on actions that are not within the control of individual sources and, based on these actions, sets standards of performance that cannot be achieved by those sources. The Proposed Trading Plan Rule is unlawful because it implements these impermissible, unachievable standards of performance for states that do not submit a plan or submit a plan that EPA disapproves.

In the final Section 111(d) Rule, EPA claims that "the phrase 'best system of emissions reduction,' . . . . is capacious enough to include … actions that may occur off-site and actions that a third party takes pursuant to a commercial relationship with the owner/operator."[18] EPA further states that the "purpose of the definition of stationary source is jurisdictional in nature" and "[a]s a practical matter, the 'source' includes the 'owner or operator' of any building, structure, facility, or installation for which a standard of performance is applicable." [19] With these new assertions, EPA further divorces the final Section 111(d) Rule from Section 111(d)'s requirements.

First, a standard is not "achievable" if the source must rely on other entities that it does not control or cease operation in order to comply. Second, an owner or operator does not fall within the definition of "stationary source."[20] Third, the definition of "stationary source" cannot be read narrowly as jurisdictional rather than as a substantive definition where it was intended to apply for purposes of the entire Section 111.[21] The "need to rewrite clear provisions of the statute should have alerted EPA that it had taken a wrong interpretive turn."[22] Thus, because the

[17] 80 Fed. Reg. at 64,974 and at 64,968
[18] 80 Fed. Reg. at 64,761
[19] *Id*. at 64,762.
[20] CAA § 111(a)(3
[21] *See* CAA § 111(a) (applying the definition of "stationary source" "[f]or purposes of [section 111]").
[22] *UARG v. EPA*, 134 S. Ct. at 2446.

Proposed Trading Plan Rule would rely on the impermissible BSER established in the final Section 111(d) Rule to establish emission limitations that are not achievable for individual EGUs, the Proposed Trading Plan Rule is also unlawful.

3. The Proposed Trading Plan Rule Impermissibly Intrudes on the Authority of State and Local Governments.

EPA's Proposed Trading Plan Rule intrudes into the sphere of authority over EGUs that federal law has reserved to state and local governments in Part II of the Federal Power Act ("FPA"),[23] the Tenth Amendment to the Constitution, and in the principles of cooperative federalism in the CAA, including Section 111(d).

First, the Proposed Trading Plan Rule intrudes on the traditional state and local authority over electric utility service. Part II of the FPA establishes clear lines between traditional state and local authority over the provision of electric utility service and the limited jurisdiction given to FERC. The FPA, like its sister statute, the Natural Gas Act,[24] "was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way."[25] Thus, Congress declared in Section 201(a) of the FPA that the "business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest," yet federal regulation was "necessary" only for discrete elements of that business—interstate transmission, sales at wholesale, and "matters related to generation to the extent provided" in the FPA—with "such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States."[26] Section 201(b) allows FERC regulation of "the transmission of electric energy in interstate commerce" and "the sale of electric energy at

[23] 16 U.S.C. §§ 824–824*w*
[24] 15 U.S.C. § 717–717*w*
[25] *ONEOK, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1599 (2015) (quoting *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n of Ind.*, 332 U.S. 507, 517–18 (1947)).
[26] *Id.*

wholesale in interstate commerce," but not of "any other sale of electric energy."[27] Section 201(b) further provides that FERC

> shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided …, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[28]

The Supreme Court has noted that the FPA's "legislative history is replete with statement's describing Congress' intent to preserve state jurisdiction over local facilities."[29]

The Court also has emphasized that federal regulation of electric generation facilities by agencies other than FERC may not invade the domain of traditional authority that the FPA has preserved for the states. In *Pacific Gas & Electric Company v. State Energy Resources & Development Commission*, the Court concluded that federal regulation of the safety of nuclear power plants did not displace "state power over the production of electricity."[30] As the Court explained, states have "traditional authority over the need for additional generation capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like."[31]

The Proposed Trading Plan Rule also intrudes on local government authority over electric utility service. For public power utilities, Congress' intent to preserve state and local control is even clearer—Section 201(f) of the FPA states that no provision of Part II of the FPA applies to "a State or any political subdivision of a State" unless a particular FPA provision expressly so provides.[32] Public power utilities are thus generally exempt from FERC regulation and subject

[27] 16 U.S.C. § 824(b)(1).
[28] *Id.*
[29] *New York v. FERC*, 535 U.S. 1, 22–23 (2002).
[30] 461 U.S. 190, 208 (1983).
[31] *Id.* at 212.
[32] 16 U.S.C. § 824(f).

to oversight by state, municipal, or other local bodies (even as to wholesale sales and transmission).

The Proposed Rule intrudes upon this local control of public power utilities. Most state laws allow for autonomous self-governance of their state and municipal public power utilities, most often by a board of directors or commissioners, which may be appointed or elected. The governing boards of public power utilities determine the composition of the utilities' generation resource portfolios (the development and retirement of specific generation units) and how their generation fleets are operated and dispatched to meet the requirements of their customers. State utility commissions typically have limited or no regulatory authority over public power utilities. In some instances, state utility commission approval of new generation units may be required through the issuance of a certificate of public convenience and necessity. But state utility commissions typically do not otherwise regulate public power utilities in their states. Therefore, public power utilities, subject to state and local oversight, determine the size and composition of their EGU portfolios, evaluating such critical matters as operating characteristics; cost; fuel use, delivery, and storage needs; land use; water use and water-quality impact; noise; visual impact; local environmental impact; and greenhouse gas emission rates. State and local public power utilities need to control the local generation mix, as well the physical operation of individual EGUs, in order to manage multiple policy objectives while ensuring safe, affordable, and reliability electric service to the public to which they are ultimately responsible.

Second, EPA's assumption of authority in the Proposed Trading Plan Rule would commandeer state legislative authority and is, therefore, also inconsistent with the Tenth Amendment to the United States Constitution, which declares that "[t]he powers not delegated to

the United States by the Constitution, nor prohibited by it to the states, are reserved to the states respectively, or to the people."[33]

Third, EPA's contrary claims notwithstanding,[34] the Proposed Trading Plan Rule is inconsistent with the principles of cooperative federalism in the CAA. Section 111(d) is narrowly tailored and gives states primary authority to develop standards of performance for existing sources.[35] Rather than following this cooperative federalism framework, in the final Section 111(d) Rule, EPA has assumed the states' roles by establishing stringent standards of performance for existing sources. The Proposed Trading Plan Rule, which would impose these *already established* binding emissions performance obligations on EGUs, violates Section 111(d) for the same reasons. EPA's proposal is a far cry from the ministerial role envisioned by Congress in the CAA, whereby EPA establishes procedures and determines whether state plans are satisfactory.[36] Rather, EPA has established binding limits for each state and will impose those binding limits through a federal plan where states do not acquiesce.

4. The Proposed Trading Plan Rule Intrudes on FERC's Authority.

EPA's Proposed Trading Plan Rule also impermissibly intrudes on the authority Congress granted exclusively to FERC. Under Part II of the FPA, FERC has exclusive jurisdiction over interstate transmission and wholesale electricity sales of public utilities (which, as noted above, do not include public power utilities).[37] Section 310(a) of the CAA specifies that the Act "shall not be construed as superseding or limiting the authorities and responsibilities,

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[33] U.S. Const. amend. X.
[34] *see* 80 Fed. Reg. 64965, 64968
[35] CAA § 111(d)(1) (providing that "each state shall submit to [EPA] a plan which . . . establishes standards of performance" for existing sources within the state and limiting EPA's authority to "establish[ing] a procedure" for the submission of such plans).
[36] *See* CAA § 111.
[37] *See* 16 U.S.C. § 824(b); *FPC v. Fla. Power & Light Co.*, 404 U.S. 453, 469 (1972); *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986).

under any other provision of law, of the Administrator or any other Federal officer, department, or agency." The Proposed Trading Plan Rule, by implementing the Section 111(d) Rule, violates this provision because it interferes with FERC's exclusive authority to regulate interstate transmission and the wholesale sale of electric energy, promote the voluntary regional coordination of generation and transmission facilities, and ensure reliability of the bulk-power-system.

B. EPA's Proposed Procedures for Imposing Final Federal Plans Are Unlawful.

EPA states in the preamble to the Proposed Trading Plan Rule that "federal plans will be ready to be promulgated quickly in cases where states have failed to submit a plan or their plans are found unsatisfactory."[38] Moreover, the agency intends "to promulgate federal plans promptly for states who do not submit plans or initial submittals by September 6, 2016."[39] Yet EPA "is not providing specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied."[40] Instead, EPA "currently envision[s]" that a particular state's federal plan

> would be in the form of a new section to the state-specific subparts of part 62 and would be ministerial in nature. It would likely provide that the affected EGUs in each such state are subject to a federal plan and would then cross-reference or incorporate by reference the substantive provisions of one of the two subparts proposed in this action (if finalized), along with any applicable modifications or adjustments as may be necessary, either based on new information or in response to comments regarding the application of the federal plan to that particular state.[41]

While this description of the envisaged procedure is not entirely clear, it does not appear to contemplate issuing a notice of a proposed federal plan for a particular state before "quickly" and

[38] 80 Fed. Reg. at 64,975
[39] *Id.*
[40] *Id.* (footnote omitted).
[41] *Id.*

"promptly" promulgating a final federal plan for the state when EPA determines that step is warranted. EPA acknowledges in a footnote that the "minimum contents of a notice of proposed rulemaking under the CAA are set forth at CAA Section 307(d)(3) and 5 U.S.C. § 553(b)," the provision of the Administrative Procedure Act (APA) governing notice-and-comment rulemaking.

EPA's proposal to issue final federal plans for specific states without first proposing those plans would violate both the CAA and APA and should be withdrawn. These statutes and basic tenets of administrative law require EPA to propose a federal plan before imposing a final plan on a state.

As noted above, EPA has not proposed any regulatory text that would become the final federal plan on any state.[42] Instead, EPA plans to impose federal plans on specific states simply by promulgating final federal plans. EPA asserts that any state-specific federal plan elements would be "ministerial in nature" and would likely consist of cross-references to EPA's final model trading rules, plus "applicable modifications or adjustments as may be necessary." [43] In the preamble to the proposal, EPA suggests that these procedures satisfy the "minimum contents of a notice of proposed rulemaking" set forth in CAA Section 307(d)(3) and APA Section 553(b).[44] They would not.

APA section 553(b) states the following:

> (b) General notice of proposed rule making shall be published in the Federal Register, unless persons subject thereto are named and either personally served or otherwise have actual notice thereof in accordance with law. The notice shall include—

[42] 80 Fed. Reg. 64,975
[43] *Id*.
[44] *Id*. at 64,975 n.15

> (1) a statement of the time, place, and nature of public rule making proceedings;
>
> (2) reference to the legal authority under which the rule is proposed; and
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> (3) either the terms or substance of the proposed rule or a description of the subjects and issues involved.

Under this statute, any final rule must be the logical outgrowth of an agency's proposal, and it must fairly apprise interested persons of the subjects and issues addressed by the rulemaking.[45] EPA cannot satisfy this standard by issuing final federal plans for specific states based on the Proposed Trading Plan Rule. As EPA acknowledges, there are no state-specific provisions in the Proposed Rule.[46] EPA also admits that the general provisions in the proposal may have to be modified or adjusted to fit each state's unique circumstances.[47] Further, the Proposed Trading Plan Rule itself contains many unresolved matters, including such major issues as whether to adopt a mass- or rate-based trading plan, how to distribute allowances in a mass-based plan, and what types of renewable energy generation should qualify to generate emission rate credits in a rate-based program. When the range of possible policy outcomes is a broad as it is here, the public cannot reasonably be expected to have been adequately apprised of the issues. Therefore, based on the Proposed Trading Plan Rule, issuance of final federal plans for specific states cannot satisfy the APA standard.

CAA section 307(d)(3) imposes even more stringent requirements than the APA:

> (3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, shall be accompanied by a statement of its basis and purpose, and shall specify the period available for public comment (hereinafter referred to as the

[45] *See, e.g.*, *Long Island Care at Home, Ltd. v. Coke*, 551 U.S. 158, 174 (2007) (citing cases);.*American Iron & Steel Institute v. EPA*, 568 F.2d 284, 293 (3d Cir. 1977).
[46] 80 Fed. Reg. at 64,975
[47] *Id.*

> "comment period"). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of—
>
> (A) the factual data on which the proposed rule is based;
>
> (B) the methodology used in obtaining the data and in analyzing the data; and
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> (C) the major legal interpretations and policy considerations underlying the proposed rule.

The D.C. Circuit has explained that Section 307(d) requires EPA to issue a proposed rule and to provide a detailed explanation of its reasoning at the proposed rule stage.[48] The Proposed Trading Plan Rule does not meet either of these requirements.

First, the CAA requires EPA to propose the rule that it intends to finalize, not just a description of that rule. As noted above, EPA has conceded that it has not proposed any regulatory text that would, if finalized, actually promulgate a federal plan.[49] EPA cannot satisfy its Section 307(d) obligations without proposing that text.

Second, EPA cannot satisfy its "statement of basis and purpose" obligations without publishing the state-specific "factual data" that would form the basis of any state-specific federal plan. EPA's general proposal, which lacks all of the state-specific factual data that would necessarily underlie any final federal plan for an individual state, fails to provide the requisite statement of basis and purpose.

Finally, EPA's claim that applying a federal plan to individual states is a "ministerial" act, and the suggestion that notice-and-comment rulemaking is not warranted for such an action, is untenable. Subjecting an individual state to a particular set of rules designed to implement a

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[48] *See, e.g.*, *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 519 (D.C. Cir. 1983).
[49] 80 Fed. Reg. at 64,975

federal requirement, and creating the necessary bespoke regulatory provisions for an individual state, are significant rulemaking actions that demand full notice-and comment rulemaking procedures. This requirement cannot be circumvented through a partial proposal of significant regulatory requirements.

C. EPA's Analysis of Remaining Useful Life Violates the CAA.

Section 111(d)(2) of the CAA states that, when promulgating a federal plan to implement a Section 111(d) standard of performance, "the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."[50] As the Proposed Trading Plan Rule notes, this language tracks the language in Section 111(d)(1) with respect to state plans, suggesting that EPA is obligated to consider remaining useful life to the same extent that states must.[51] EPA has failed to satisfy that obligation.

The Proposed Trading Plan Rule states that EPA determined in the final Section 111(d) Rule that adjustments to performance rates or overall state emission goals could not be justified based on consideration of remaining useful life.[52] EPA thus determines that its consideration of this issue is completed: "Because the Guidelines do not allow for states to deviate from state goals based on remaining useful life, the EPA does not believe such goal adjustments are necessary or appropriate in the federal plan either." Nevertheless, the Proposed Trading Plan Rule presents a brief analysis of remaining useful life.[53]

This analysis is conclusory and inadequate. EPA asserts, for example, that it is "confident the proposed federal plan will not force costly pollution control investments at older

[50] CAA § 111(d)(2).
[51] 80 Fed. Reg. at 64,982
[52] *80 Fed. Reg. 64,982*
[53] *Id*. at 64,982-84.

plants with short remaining useful lives."[54] EPA, however, has provided no evidence to support this opinion.

EPA also asserts that it has been given "a substantial degree of discretion in determining how the 'remaining useful lives' factor is considered."[55] Using that purported discretion to substitute for an evidence-based analysis, the Agency "propose[s] that the federal plan adequately considers 'remaining useful lives' of affected EGUs by providing for trading and other flexibilities authorized in the [final 111(d) Rule]."[56] Thus, EPA's entire assessment of remaining useful life consists of a summary of what are, in EPA's view, some of the general benefits of emission trading programs: "Relatively long periods for affected EGUs to come into compliance, the ability to credit early action, the use of emissions trading, the use of multi-year compliance periods, and the ability to link to other federal or state plans to create larger emissions markets."[57] EPA also cites the incentives for early action under the Clean Energy Incentive Program (CEIP).[58]

This limited analysis fails to satisfy the CAA's consideration requirement for two reasons. First, whatever discretion the states or EPA may have to take into account remaining useful life when promulgating state or federal plans implementing a Section 111(d) standard, they do not have discretion to determine in advance that remaining useful life will not be used to adjust any standard of performance for any EGU, and thus make the actual consideration of the factor an empty exercise. Nevertheless, EPA admits to making that very determination in the Proposed Trading Plan Rule, *before* turning to its putative analysis:

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[54] *Id*. at 64,983
[55] *Id*.
[56] *Id*.
[57] 80 Fed. Reg. 64,982
[58] *Id*.

> Because the Guidelines do not allow for states to deviate from state goals based on remaining useful life, the EPA does not believe such goal adjustments are necessary or appropriate in the federal plan either. Nonetheless, this does not obviate the requirement that the EPA itself, in the design of its federal plan, consider, among other factors, the remaining useful lives of the affected facilities. The agency therefore proposes the following analysis of this factor.[59]

Second, the text of the CAA and, even the precedent that EPA relies on,[60] make clear that a remaining useful life analysis must be EGU-specific. The analysis cannot consist of a generalized determination that a regulatory program is sufficiently flexible that individualized remaining useful life assessments are unnecessary, as EPA has proposed here.

In sum, the CAA does not support EPA discretion to ignore remaining useful life or to address it only in a generalized manner, and the Agency has provided no rational justification for rejecting the use of source-specific remaining useful life analyses in the Proposed Rule.

V. EPA Underestimates the Cost of Electricity to Consumers Arising from the Proposed Rule

A. APPA Concurs with the Findings in the NERA Study That Prices Will Rise as a Result of the Section 111(d) Rule.

As a result of the Section 111(d) Rule, additional coal-fired plants will be forced to retire early, which will lead to greater reliance on natural gas all while continuing to maintain and pay for a retired coal plant in many cases, see discussion in section V.D. of these comments. This fuel switching, in conjunction with other technological, capital, transmission, and other related investments, will help push electric rates far higher than they would be under a business-as-usual

[59] *Id*.

[60] EPA cites the CAA's regional haze program and the requirement to consider remaining useful life in assessing best available retrofit technology ("BART") requirements as a guiding authority on how EPA should consider that factor under Section 111(d). 80 Fed. Reg. at 64,983. EPA neglects to mention, however, that BART is a source-specific assessment focused on individual EGUs. Anything more generalized would not be permissible under the CAA's BART provisions. Accordingly, EPA's reliance on BART undermines its position on its authority to disregard a source-specific remaining useful life analysis in the Proposed Trading Plan Rule.

scenario. Detailed economic modeling based on the above assumptions more succinctly show how these changes will impact rates.

NERA Economic Consulting (NERA) has conducted two mass-based modeling scenarios on the impacts of the Section 111(d) Rule.[61] NERA's analysis incorporates modeling of the electric sector, as well as the entire U.S. economy. NERA found that the Section 111(d) Rule would increase rates from 11 to 14 percent per year relative to baseline projections without the Section 111(d) Rule. NERA also modeled all 50 states, and its model shows that 40 states could have price increases of 10 percent or more, 17 could have price increases of 20 percent or more, and 10 states could have price increases of 30 percent or more. Additionally, seven states could have peak price increases of 40 percent or more.

These sharp price increases will have further economic impacts. NERA's model forecasts that the total consumption loss from 2022-2032, as a result of the Section 111(d) Rule, would be between $64 billion and $79 billion. The Section 111(d) Rule would thus cause consumers to pay more for electricity and would have a negative impact on the general economy.

Energy Ventures Analysis (EVA) performed a similar analysis, and also concluded that the Section 111(d) Rule would increase rates.[62] EVA employed a modeling system that determined the lowest system cost compliance mix, calculated carbon penalties, and projected fuel prices based on demand. This analysis found that the Section 111(d) Rule would lead to an additional $214 billion in wholesale electric spending between 2022 and 2030, compared to a scenario with no Section 111(d) Rule. Another $64 billion is projected to cover the cost of

[61] NERA Economic Consulting, *Energy and Consumer Impacts of EPA's Clean Power Plan*, November 7, 2015. The compliance scenarios are mass-based with intra-state trading, and mass-based with regional trading. The scenarios also included an assumption that there would be no LDC allocation of carbon credits, and one with a 50 percent allocation.

[62] Energy Ventures Analysis, *EPA's Clean Power Plan: An Economic Impact Analysis,* prepared for the National Mining Association (NMA).

replacing the 41 gigawatts (GW) of coal-fired generation that will be prematurely retired. Ultimately, EVA projects 46 states to experience double-digit wholesale price increases in 2030, with 16 states experiencing an increase of at least 25 percent.

Shifting from coal-fired generation to natural gas would increase overall demand for natural gas, which in turn would lead to natural gas prices higher than what EPA forecasts in the RIA. These higher natural gas prices would be felt by natural gas consumers outside of the electric industry. EVA also notes that EPA has not fully accounted for the cost to consumers for enhanced transmission infrastructure resulting from early coal-fired plant retirements.

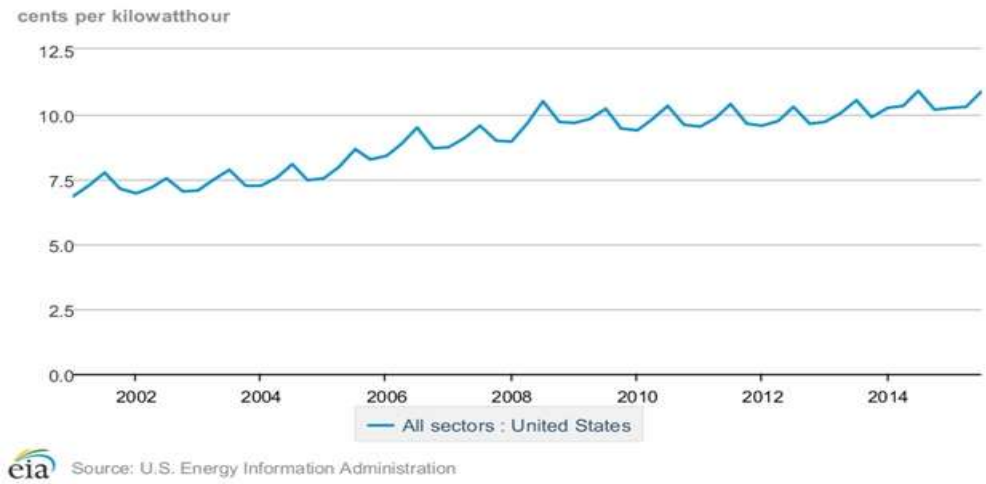
The Section 111(d) Rule will thus have far-reaching electric rate and economic consequences. As these analyses show, consumers will bear the costs associated with the changes needed to meet EPA standards. Higher electric rates will have a doubly negative impact on the economy. First, consumers will have less disposable income due to paying higher electric bills. Second, industrial and commercial consumers will pass through these electric rate increases in the prices they charge for the goods they sell, thereby increasing economy-wide costs. The impacts of the Section 111(d) Rule will thus be felt by the larger United States economy, and not just the electric industry.

B. Electricity Prices Generally Continue to Rise and Will Likely Further Do So under the Final Section 111(d) Rule and Proposed Rule.

There is currently a broad disparity of electricity prices in the United States. This disparity ranges from a low of 7.13 cents/kwh in the state of Washington to a high of 33.43 cents/kwh in the state of Hawaii, according to U.S. Energy Information Agency (EIA) data on 2014 retail electricity prices. In addition, the cost of producing and delivering electricity has been increasing, and as noted above, is projected to continue to do so. There are numerous reasons for this, including increases in the cost of building materials and fuel, and the cost of

complying with various local, state, and federal mandates and regulatory requirements. Figure 1 shows these retail electricity cost increases for residential customers. EIA predicts that costs to residential customers will continue to rise, even with the anticipated deployment of energy efficiency programs. For public power utilities, all of these costs are passed on to consumers in the form of monthly bills.

Figure 1: Average Retail Price of Electricity



APPA does not agree with EPA's stated assumptions and conclusions about low- or no-cost of compliance with the Section 111(d) Rule. As noted in the summary of these comments and elsewhere, APPA believes there is a significant potential for substantially increased costs to consumers in many states resulting from stranded generation assets and the cost of new generation and related infrastructure necessary to comply with the Section 111(d) Rule, among other things. These increased costs are forecast in several studies, including one conducted by NERA, as discussed in section IV.A. Moreover, these new costs will be added to the already increasing costs faced by consumers as discussed above.

In the Proposed Model Trading Plan, EPA has an opportunity to partially mitigate some of these costs. As noted earlier and assuming the final Rule withstands judicial review, the key to making the entire program at least somewhat more workable for utilities and more affordable for consumers lies in the trading programs available for compliance. Therefore, APPA again urges EPA to adopt the recommended changes to the Proposed Rule contained in these comments. To better assist the Agency in considering doing so, APPA offers additional information in the following sections on the various situations and factors that are driving costs upward and that in some cases would be exacerbated by adopting the Model Trading Plan as proposed.

C. Costs in RTO Markets

As discussed below, electricity prices are also rising faster in regions of the country where wholesale electricity markets are administered by FERC-approved Regional Transmission Organization (RTOs) or Independent System Operators (ISOs) (collectively referred to in this section as RTOs), especially those that also have mandatory capacity markets. Moreover, as discussed in APPA's 2014 comments on the proposed Section 111(d) Rule, RTOs with mandatory capacity markets also present significant barriers to the construction of new, lower- or non-emitting generation sources. The obstacles and the delays inherent in these markets impose substantial additional costs on consumers for Section 111(d) compliance whether through an approved state plan or a federal plan.

There are currently six operational RTOs under the jurisdiction of FERC: ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Midcontinent ISO (MISO), California ISO (CAISO), and Southwest Power Pool (SPP). The Electric Reliability Council of Texas operates as an ISO solely within the Texas intrastate transmission grid and is

therefore regulated by the Public Utility Commission of Texas and not by FERC. These RTOs were formed to operate the bulk transmission grids within their respective regions. The facilities comprising these regional grids are owned by multiple investor-owned, public power, and cooperative utilities. In addition, these RTOs operate wholesale electricity markets that affect the operation and dispatch of existing electric generation units, decisions concerning the retirement of existing units, and decisions concerning the construction of new units.

All RTOs operate markets for wholesale energy and ancillary services, while three of the FERC jurisdictional RTOs also operate markets for capacity. In the RTO-operated wholesale energy markets, electricity is typically dispatched every five minutes, first in the day-ahead and then in the real-time market. Generators submit price offers to sell power, and load-serving entities submit load forecasts, to the RTO. Subject to transmission and other operational constraints, the RTO commits and dispatches generating units in order of lowest to highest offer to meet the forecasted load. This procedure is commonly known as Security-Constrained Economic Dispatch (SCED). (There are many descriptions of SCED that refer to resources being dispatched in order of least to highest *cost*, but generators need not offer to sell at their actual cost of producing the electricity.)

In any event, generator offers are generally subject to an offer cap that is typically $1,000 per MWh, and in some circumstances, are subject to "mitigation" (i.e., reduction) by the RTO "market monitor" to cost-based levels. (An exception to the cap occurs during shortage pricing events, when supplies of electricity are tight, and prices are allowed to rise to a higher cap.) RTOs use locational marginal pricing (LMP) in the energy markets to reflect pricing differentials that occur when transmission congestion prevents the RTO from dispatching generating units with the lowest-priced offers and the RTO must therefore dispatch a unit with a higher offer

price to serve RTO loads within a constrained zone. While the wholesale energy market is where the purchase and sale of electricity occurs from existing resources in RTO regions, the RTO capacity markets are intended to provide revenue for the development of new generation resources and to cover the costs of keeping existing resources ready to supply this electricity when needed. The ability of the RTO capacity markets to accomplish their goals is highly questionable and in some cases these markets are impeding new resource development.

EPA states in the Regulatory Impact Analysis (RIA) for the Proposed Rule that the Agency is using the same methodology as in the Section 111(d) Rule, which relies on the Integrated Planning Model (IPM) developed by ICF Consulting, Inc. According to EPA, the IPM "provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraint. The model is designed to reflect electricity markets as accurately as possible." But as described in the IPM documentation, IPM "models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry, or uncertainty."[63]

Yet the RTO-operated wholesale energy and capacity markets are far from perfectly competitive markets and rarely select the least cost options for capacity expansion. Because the merchant generators operating within these markets will take actions to maximize their earnings and because the prices are not regulated on a cost-basis, prices can exceed the costs of generating electricity. During periods of constrained supply, this differential can be significant. For example, the Market Monitor for PJM found in the most recent State of the Market report that

[63] "Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, Nov. 2013," Chapter 2: Modeling Framework, http://www.epa.gov/powersectormodeling/docs/v513/Chapter_2.pdf

"the behavior of some participants during the high demand periods in the first quarter raises concerns about economic withholding. Given the structure of the energy market, the tighter markets and the change in some participants' behavior are sources of concern in the energy market."[64]

Even when supply is not constrained, prices can diverge from actual costs, as can be seen by recent data on "spark spreads," which are a primary indicator of the profitability of natural gas plants. Spark spreads measure the differential between the electricity price and the cost of electricity produced by a natural gas plant based on current natural gas prices, assuming a heat rate of 7,000 Btu per kilowatt-hour. Looking at the spark spreads for just one recent morning is by itself revealing. On December 21, 2015, when average natural gas costs had fallen below $2 per million Btu in many regions, the highest spark spread was $21.74 per MWh in Western PJM where gas prices were $1.13 per million Btu. Given that the electricity price in this region was $29.66 per MWh, the mark-up over costs for an efficient natural gas plant was equal to almost 75 percent of the price.[65] In New England, at the Massachusetts Hub, where gas prices remained close to $3, the spread was 30 percent of the electricity price, and in New York City the spread was almost half of the electricity price.

FERC and many of the RTOs are exploring various changes to the energy price rules that are likely to increase energy prices. Such changes include a recently-approved doubling of the offer cap at PJM from $1,000 to $2,000 per MWh, and a proposal that would permit generators to revise their energy market offers on an hourly basis, regardless of the underlying cost. Moreover, several RTOs have increased their shortage pricing caps and a recent Notice of

[64] Monitoring Analytics, 2015 Quarterly State of the Market Report for PJM: January – September, page 76, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q3-som-pjm-sec3.pdf
[65] *US Energy Information Administration*, "Today in Energy," as posted on December 21, 2015, http://www.eia.gov/todayinenergy/prices.cfm. Prices are posted on a daily basis.

Proposed Rulemaking by FERC that would require RTOs to increase the frequency of shortage pricing events, which if finalized would make energy price spikes a more regular occurrence in the RTO markets.

Concerns about market power and increasing prices are even more significant in the RTO-operated capacity markets. For example, the most recent auction for capacity for the 2015/16 time frame in MISO resulted in a price for Zone 4 in Illinois that was nine times the prior year's price for that zone.[66] Complaints filed with FERC about these auctions results noted that a single entity, owning about 60 percent of the capacity resources participating in Zone 4, submitted offers significantly above other offers, which set the price.[67] Moreover, the supplier apparently exerted a strong influence on the stakeholder process in opposition to a proposal to combine Zones 4 and 5 which would have mitigated a single suppliers' influence on the price. FERC has since opened up a non-public formal investigation into "whether market manipulation or other potential violations of Commission orders, rules and regulations occurred before or during the Auction."

In the ISO NE capacity market, FERC Commissioners Tony Clark and Norman Bay found that regarding the February 2014 auction for generating capacity in ISO-NE, "there is evidence suggesting the exercise of market power, and it is uncontroverted that the market power, if it existed, was not mitigated. In the words of ISO-NE, prices resulted from a

[66] Midwest Independent System Operator, 2015/2016 Planning Resource Auction Results (Extended), https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=199975

[67] Complaints of the People of the State of Illinois By Illinois Attorney General Lisa Madigan (Docket EL 15-70-00), May 28, 2015, Public Citizen, Inc. (Docket EL15-71-000), May 28, 2015 and Southwestern Electric Cooperative, Inc. (Docket EL15-71-000), May 29, 2015, Federal Energy Regulatory Commission. www.ferc.gov.

'noncompetitive auction.' To the extent any portion of those prices was attributable to an exercise of market power; the auction will have imposed unwarranted costs upon consumers."[68]

In addition to these market imperfections, the costs of implementing the Proposed Rule will be exacerbated by capacity market rule changes that constrain supply, often to the advantage of the merchant generators, whose owners have a financial interest in limiting available capacity as a means to keep prices high. For example, in response to state-initiated efforts by Maryland and New Jersey in 2011 to procure new, more efficient natural-gas fired units, a group of merchant generators responded by requesting and receiving approval from FERC for a tightening of Minimum Offer Price Rule (MOPR) that can impede the entry of new generation.[69] Similar rules were implemented in ISO-NE, but the MOPR in that RTO applies to all resources, including renewable energy (other than a small exemption).

In a commentary on these merchant generator-influenced rule changes, a May 2014 Navigant Economics paper, predicted that as a result of efforts to reduce CO_2 emissions, "the effects of energy efficiency improvements on capacity prices will likely be substantial, depressing prices for many years, and calls for further changes to capacity markets to reduce this effect might be expected."[70] In fact, recent rule changes in the PJM and ISO NE capacity markets have already placed additional barriers to renewable energy, energy efficiency, and demand response. These rule changes, referred to as "capacity performance" in PJM or

[68] Joint statement of Commissioners' Clark and Bay on ISO-New England's Forward Capacity Market Case, Sept. 16, 2014, Docket ER14-1409, http://www.ferc.gov/media/statements-speeches/clark/2014/09-16-14-clark.asp#.VF0bPsm5QfE

[69] For more details, see the APPA Fact Sheet, RTO Capacity Markets and Their Impacts on Consumers and Public Power, available at: http://publicpower.org/files/PDFs/RTOCapacityMarketsandTheirImpactsonConsumersandPublicPowerFSMay2015.pdf

[70] *Cliff Hamal, Navigant Economics*, Markets Matter: Expect a Bumpy Ride on the Road to Reduced CO_2 Emissions (May 2014)

"performance incentives" in ISO New England. In New England, generators that are not operating or not providing reserves during scarcity conditions are subject to stringent penalties, encouraging resources not meeting this requirement to face significantly higher costs. PJM has placed new capacity performance requirements on all resources that wish to participate in the capacity auction similarly requiring resources to be available during emergency periods. These rules carried significant capacity price increases in both RTOs and will strongly benefit baseload resources, such as nuclear and coal, and fast-start flexible natural gas-fired resources. Variable resources, such as renewable energy, demand response, and energy efficiency programs, will be disadvantaged.[71]

To the extent that merchant generators are able to erect additional barriers to new construction of natural gas generation, renewable resources, and energy efficiency, so too will the capacity and energy market costs increase beyond what was modeled by the IPM.

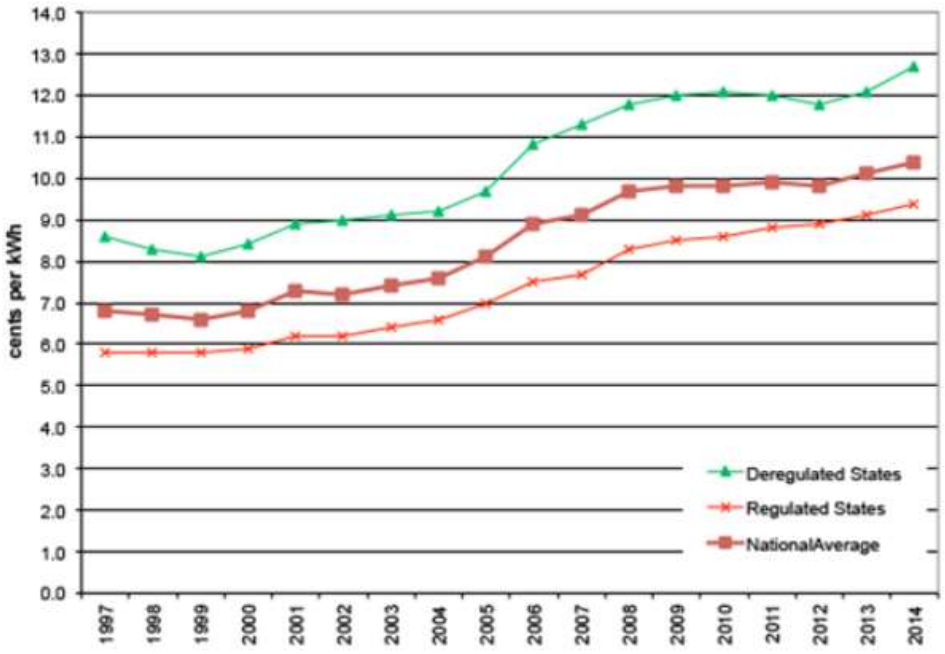
1. Retail Electricity Prices Are Rising at a Faster Rate in States Within RTO Markets.

The discussion in the two preceding sections illustrates in part why wholesale electricity prices are rising at an even faster rate in regions of the country where the wholesale markets are administered by RTOs subject to jurisdiction of FERC, and where the states chose to restructure their retail electricity markets. These states generally ceded authority over their state's generating facilities to FERC. This lack of direct state authority over electricity generation substantially dilutes the ability of states, through their public service commissions, for example, to protect consumers from excessive power prices.

[71] See Protest of Public Interest Organizations, Protest of AMP, ODEC, SWMECO, Federal Energy Regulatory Commission, Dockets ER15-623-000, EL15-29-000 (January 20, 2015); Protest of Public Power Utilities, Protest by Connecticut and Rhode Island, New England Power Pool, Federal Energy Regulatory Commission, Dockets ER14-1050-000, ER-14-1050, 001 (February 12, 2014).

The largest component, by far, of a customer's electricity bill is the cost of the power itself. Thus, increases in the wholesale cost of power are reflected in the monthly retail bills paid by consumers. The chart below shows the national average of retail rates for all states from 1997 (roughly the beginning of electricity market restructuring) and 2014, the most recent year for which this data is available. The national average is contrasted with the average of states that have restructured their retail electricity markets, all of which are located within RTOs,[72] and those that have not. The chart shows that, again, while electricity rates are increasing everywhere, they are rising at a faster rate in states that have restructured their retail electricity markets and are more dependent on RTO markets for wholesale power supply.

Figure 2: Average Electricity Rates Deregulated vs Regulated State



[72] With the exception of parts of Montana.

D. Weakening Credit Ratings Would Limit Public Utilities Access to Capital and Raise Costs for Consumers.

APPA is concerned that, without changes to the Proposed Model Trading Plan, compliance with the Section 111(d) Rule could weaken credit ratings for some public power utilities, thus further increasing costs for consumers. Electric utility rates for public power utilities in the U.S. are designed to yield revenues equal to a utility's total cost of service ("COS"), which includes all capital and operating costs incurred to provide service to their customers. When the utility's average COS rises, electricity prices (electric rates) for consumers must also rise, and it is important to recognize that when Section 111(d) compliance strategies lead to higher average costs for these utilities, the effects are felt directly by the consumers, who are also the owners of the utility, in the form of higher electricity prices.

As noted elsewhere in these comments, compliance with the Section 111(d) Rule will likely put direct, upward pressure on electricity rates for a number of reasons. First, it will result in the premature shutdown of some otherwise economically viable coal generating units which will lead to significant replacement power costs, whether the coal output is replaced by natural gas combined cycle units (NGCC), new renewable resources, or a combination of both. Indeed, even if the coal output is replaced by relatively low cost energy efficiency measures, the displacement of utility output and sales can lead to higher average costs and higher rates and bills for at least some consumers. The Section 111(d) Rule will also lead to increased costs from dispatching existing gas plants at higher capacity factors ("CF"). In addition, the increased demand for natural gas as a replacement resource will put upward pressure on gas prices, which will increase the cost for all gas generation resources. This will also increase costs to homeowners that rely directly on natural gas for energy services.

In addition to increasing direct costs, compliance strategies, may also lead credit rating agencies to impose negative impacts on utility credit ratings over a variety of financial activities, which could result in higher borrowing costs that will ultimately be borne by consumers. Credit ratings can be affected in three ways. First, the need for replacement power will likely lead to higher levels of debt, and/or other fixed obligations, thus impairing key credit metrics, especially coverage and liquidity ratios, used by rating agencies to develop their ratings. Second, a reduction in fuel diversity (by eliminating coal as a portfolio option) exposes utilities to greater fuel price risks. Third, rate increases that public power utilities must implement to recover higher replacement costs can compound the effects of other factors (e.g., macroeconomics, energy efficiency, net metering, and other distributed generation initiatives) that lead to reduced sales and higher rates, thus impairing credit ratings by destabilizing the utility's financial integrity.

This third factor highlights a troublesome "catch 22" dynamic, whereby the remedy for deteriorating credit metrics, higher rates, can itself lead to deteriorating metrics. So, even if one chose to ignore the immediate impacts of higher electric rates on consumers, rate increases stemming from Section 111(d) compliance can give rise to additional problems for utilities that will ultimately be felt by their customers.

These types of concerns are evident in recent publications from major credit rating agencies. For example, A December 2015 report by Moody's Investor Service indicates a stable outlook for public power in 2016, but expresses significant concerns over the challenges of meeting carbon reduction goals.[73] The agency notes that, "the industry's transition to cleaner sources of power is the main risk to our stable outlook. The industry's ability to transition to

[73] Moody's Investor Service, *OUTLOOK* December 2, 2015.

cleaner power while maintaining customer rates and system reliability is uncertain and is a developing risk." It adds, "the ability of public power electric utilities to transition toward cleaner power sources and away from coal, while maintaining affordable customer rates and system reliability, is uncertain and is a developing risk to our stable outlook that will play out over the next several years." Regarding rates, the report goes on to say, "Our stable outlook is based on our view that U.S. public power utilities are willing and able to raise consumer rates when needed to recover costs." And that, "the transition to cleaner power could be credit negative if ratepayers balk at the cost increases and utilities are unable to pass through higher consumer rates."

Similarly, a recent report by Fitch[74] indicates that "preserving financial margins and credit quality, while complying with EPA's Section 111(d) Rule, remains most challenging for public power and cooperative utilities operating in states subject to sizable mandated carbon-reduction goals, high carbon-reduction costs and a relatively high cost of electricity." In terms of the pressure on electricity rates, Fitch also notes that, "although the final rules appear less onerous than originally proposed and provides more time to comply, Fitch believes the effect on individual credit quality will continue to hinge on each utility's ability and willingness to recover compliance costs from end users."

It is difficult to predict the long term rate impacts of the Section 111(d) Rule on electricity process. Many factors will affect the outcomes including: the baseline level of electric rates before the Section 111(d) Rule; the specific compliance strategies implemented; long-term natural gas prices; installed costs of replacement generation resources (e.g., NGCCs and natural gas pipeline and storage facilities); variable costs and operating characteristics of replacement

[74] Fitch Ratings, *The Carbon Effect 2.0, Reassessing the Challenges for Public Power, Special Report,* October 14, 2015.

facilities (including energy efficiency and increased utilization of existing gas plants); the number of coal plants retired and associated loss of electric output; long-term coal prices; variable costs and operating characteristics of the coal plants subject to retirement; and the time horizon for the analysis. Moreover, results will vary significantly across geographic regions and political boundaries.

In a May 2015 report by EIA,[75] which preceded the release of the final rule, EIA estimated potential nation-wide rate increases in the range of 2.0-4.9 percent in 2020, 2.8-4.0 percent in 2030 and 1.1-5.9 percent in 2040. Highlighting the disparate regional effects, an October 2015 report form the Electric Reliability Council of Texas,[76] concludes that "energy costs for customers may increase by up to 16 percent by 2030 due to the Section 111(d) Rule alone, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, and other costs associated with the retirement or decreased operation of coal-fired capacity in the ERCOT Region." And, in earlier comments on the proposed Section 111(d) Rule,[77] APPA presented an analysis showing possible 20-year levelized rates increases for the public power sector of between 5.5 percent and 55.5 percent, costing consumers between $7 billion and $430 billion, as a result of premature coal plant retirements.

Others have offered different estimates of the potential rate impacts (see Section IV. A), and it really is impossible to project precisely what they will be, but it is clear that consumers will feel the financial effects of complying with the 111(d) Rule. The financial impacts to

[75] U.S. Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan*, May 2015.
[76] Electric Reliability Council of Texas, *ERCOT Analysis of the Impacts of the Clean Power Plan Final Rule Update, October 16, 2015.*
[77] Comments of the American Public Power Association (APPA) on EPA's Section 111(d) Proposed Rule for Carbon Dioxide Emissions from Existing EGUs EPA-HQOAR- 2013-0602, pp. 176. December 14, 2015.

customers will most like be experienced though the retirement of affected coal-fired EGUs resulting in a loss of economic value to communities that own/operate those generating assets.

VI. The Record Does Not Support Overarching Features of the Proposed Federal Plan.

EPA states in the Proposed Trading Plan Rule that "[t]he procedural requirements for rulemakings under both CAA Section 110 and 111(d) are set out in Section 307(d) of the CAA, and the Agency believes those provisions are appropriate and adequate to guide its rulemaking process for CAA Section 111(d) federal plans."[78] EPA is correct in its determination that Section 307(d) applies to this rulemaking. The Agency has failed, however, to meet the exacting standards that Section 307 imposes. Even if EPA's Proposed Trading Plan Rule were not unlawful—and, as described above, it is—EPA has failed to justify on the record numerous key features of its Proposed Rule. Indeed, as described below, EPA frequently makes assertions with no factual or analytical support or proposes significant regulatory provisions without the detail necessary to truly understand how implementation would occur. As such, the Proposed Trading Plan Rule should be treated as an advance notice of proposed rulemaking. Based on the information EPA receives through this process, the Agency should reconsider and substantially revise this Proposal Rule and again seek public comment on a complete and better supported proposed rule. APPA offers the following comments to assist in that effort.

A. EPA Should Adopt Mass- and Rate-Based Federal Plans.

EPA "intends to finalize a single approach (i.e., either the mass-based or rate-based approach) for every state in which it promulgates a federal plan."[79] EPA suggests this approach will "enhance the consistency of the federal trading program, achieve economies of scale through

[78] 80 Fed. Reg. at 65,038.
[79] 80 Fed. Reg. at 64,968.

a single, broad trading program, ensure efficient administration of the program, and simplify compliance planning for affected EGUs."[80] Yet, EPA notes that "[s]ome stakeholders have suggested there could be utility in the availability of both approaches based on the unique circumstances of particular states," and recognizes "that it remains potentially possible to finalize a different approach to a federal plan in some circumstances."[81]

APPA supports the concept of finalizing both mass- and rate-based federal plans. EPA should allow states that are to become subject to a federal plan to choose which type of emission trading scheme best suits their individual circumstances and the circumstances facing their EGUs. Indeed, these are the types of decisions that states are best suited to make. If a state nevertheless fails to select a federal plan type, EPA should itself evaluate the characteristics of the state and the state's EGUs to determine which type of plan will provide the most efficient and flexible path to compliance. The Agency's decisions as to the type of plan to impose and the rationale for selecting a specific plan type for a specific state should, moreover, be subject to notice and comment to allow states, regulated sources, and other interested parties an opportunity to weigh in on the type of plan that is most appropriate.

EPA's limited rationale for adopting a single plan type does not overcome the benefits that would be achieved by allowing states to select the federal plan type. First, the Agency has not demonstrated that allowing multiple plan types will not achieve economies of scale through broad trading programs. Indeed, EPA's model trading rules, which encourage states to select one plan type or the other, are premised on the assumption that two efficient and competitive markets can exist simultaneously. The country's experience with state-specific and regional trading programs, moreover, supports this view and is certainly more compelling than vaguely

[80] *Id*. at 64,970.
[81] *Id*.

stated concerns, unsupported by record evidence, about potential market size. Finally, if EPA is truly concerned about a fractured two-market system and the ill effects that might have, it could rectify that concern by creating an exchange for rate- and mass-based plan compliance instruments. Such an exchange should involve relatively simple calculations and transactions and would increase flexibility and compliance options, consistent with EPA's stated goals.

The Agency's other rationales—enhanced consistency of the federal trading program, ensured efficient administration of the program, and simplified compliance planning for EGUs—are more obscure. EPA has not demonstrated or explained why it believes consistency will be beneficial or even what it means by the term. Nor has the Agency demonstrated or explained what inefficiencies will arise under a rate- and mass-based federal plan approach. Again, those same inefficiencies, if they exist, would seem to be a feature of a rate- and mass-based state plan system as well, and EPA has not expressed the same concern in that setting. And simplified compliance, while sometimes beneficial, will be a net disadvantage for those EGUs that would fare much better under the alternative to the single plan type that EPA selects.

Indeed, all of these rationales conflict with the fundamental premise underlying the Section 111(d) Rule, as described by EPA, and the Agency's decision to provide states with rate- or mass-based (and also state measures type) plan approach options. Unless EPA can make a compelling demonstration that a single plan approach is justified—and it has not done so in the Proposed Trading Plan Rule—the Agency cannot lawfully proceed with its plan to finalize only a single type of federal plan.

1. EPA Should Adopt a Mechanism to Allow Trading Between Rate-Based and Mass-Based Plans.

EPA has proposed to allow trading only between EGUs (and other trading entities) that are covered by plans of the same types, i.e., rate-based states trade with other rate-based states

and mass-based states with other mass-based states.[82] The Proposed Trading Plan Rule rejects the possibility of emissions trading between rate-based and mass-based plans, thereby limiting the size of any emissions trading marketplace. This prohibition, if implemented, will create two distinct economic markets, one for trading ERCs and one for trading allowances. Many larger and small utilities have electric generating assets in multiple states and, therefore, may be subject to different trading schemes. The inability to bridge these two systems will result an increase in the cost of compliance, transaction costs, and other inefficiencies. EPA agrees that a "broad trading region provides greater opportunities for cost-effective implementation of reductions compared to trading limited to a smaller region, yet it does not explain its opposition to an allowance-ERC exchange.[83]

Since the Section 111(d) Rule and the Proposed Trading Plan Rule rejected, without consideration, an exchange between rate- and mass-based systems, EPA should propose a new rule inviting public comment on the design and implementation of such an exchange. Through the public comment process, other conversion factors and trading mechanisms yet to be explored might also enhance implementation of the Section 111(d) Rule and give greater flexibility to affected EGUs. APPA supports comments on this issue by the Utility Air Regulatory Group ("UARG").

B. EPA Does Not Adequately Address Reliability in the Proposed Rule.

APPA appreciates that EPA has correctly identified maintaining reliability of the electricity system as paramount in implementing the Section 111(d) Rule. APPA also appreciates the inclusion of certain provisions in the Section 111(d) Rule to ensure reliability, such as the requirement that states consider reliability in developing state compliance plans; an

[82] 80 Fed. Reg. 64,966-77.
[83] *Id*. at 64,977

opportunity to amend state plans if necessary to address reliability concerns; and a Reliability Safety Valve (RSV) that would allow EGUs needed to ensure reliability to run at higher emission standards for up to 90 days without requiring increased CO_2 emissions to be offset.

Yet, EPA does not propose to provide electricity consumers in states subject to a federal plan the same level of reliability assurance. APPA believes the federal plan must satisfy the same general reliability requirements in §60.5745(a)(7) of the Section 111(d) Rule that the affected state would be required to satisfy if it has submitted a state plan.[84] There is no material difference in either the electric system or the types of events that would trigger an RSV between states with an EPA-approved state plan or a state with an EPA-imposed federal plan. APPA does not agree with EPA that the purported flexibility inherent in the federal plan obviates the need to include an RSV, particularly in light of the many flaws in the Proposed Trading Plan Rule, as discussed in these comments. The Agency should include an RSV in any federal plan and should modify it to improve its effectiveness.

1. EPA's Decision Not to Include a Reliability Safety Valve in the Proposed Trading Plan Rule Is Arbitrary and Capricious and Inconsistent with the Section 111(d) Rule.

EPA's Proposed Trading Plan Rule would arbitrarily exclude an RSV from any federal plans that EPA promulgates. The RSV was included in the Section 111(d) Rule as "an additional assurance…for use where the built-in flexibilities [of a trading plan] are not sufficient to address an immediate, unexpected reliability situation."[85] In the Proposed Trading Plan Rule, EPA contends that an RSV is not needed because a federal plan would allow trading. [86] The Agency expected in the Section 111(d) Rule that a "virtually nationwide emissions trading market for

[84] 80 FR 64, 944; Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, October 23, 2015.
[85] 80 Fed. Reg. at 64,827
[86] *Id*. at 64,982.

compliance" would emerge to implement the final rule, and yet did not foreclose the use of an RSV.[87] Quite the contrary, EPA concluded that such a provision was an important additional component to the program. It is unreasonable for the Agency to prohibit an RSV here where, as in the Section 111(d) Rule, EPA cannot predict that an "extraordinary and unanticipated event that presents substantial reliability concerns" will not occur, and where EPA has not provided any other substantial safeguard against such an event. [88]

The Proposed Trading Plan Rule, is likely to change once finalized thus offering no assurance that states will develop approvable Section 111(d) plans with workable and cost effective emission trading programs. Therefore, the premise that no RSV is needed in a federal plan is false. Additionally, the scope of the emissions trading program EPA envisions under the Section 111(d) Rule, model trading rules, and federal plan is unprecedented. There may be insufficient allowances or ERCs available to cover an EGU's compliance obligation and account for any increased CO_2 emissions due to operating the unit for reliability reasons if an RSV is not available. If allowances or ERCs were available, they might be too costly and unduly increase electricity prices for consumers. The liquidity of allowances or ERCs is of particular concern, as some states and/or third parties have reportedly expressed an intent to withhold or retire from the market allowances or credits to further hamper the operation of coal-fired EGUs.

2. The Reliability Safety Valve Must Be Available for Longer Than 90 Days.

As noted above, EPA erroneously assumes reliability events can be addressed through the purported flexibility available to states in their compliance plans. Nevertheless, the RSV is provided for state plans approved under the Section 111(d) Rule in order to address unforeseen,

[87] *Id*. at 64,732
[88] *Id*. at 64,671.

potentially catastrophic events, but for only up to 90 days. In fact, the reliability impacts of such events can sometimes extend beyond 90 days. EPA acknowledges this to be the case, and the experience of APPA's members and other utilities confirms this point.[89] For example, during the 2005-2006 hurricane season, three major hurricanes ravaged Florida within thirteen weeks. Two of these hurricanes made landfall in the panhandle disrupting the natural gas storage facilities that supply EGUs elsewhere in the state, including those owned by public power utilities. Coal-fired EGUs in the middle of the state, however, were able to run and assist in restoring service because they had fuel stored on site.

In another example, a catastrophic failure of a generator step-up (GSU) transformer can involve years, not days or months, for repair or replacement. Laramie River Station in Wyoming has experienced just such a failure on two occasions. While there was a spare GSU on-site, it took months to remove the damaged equipment, install the spare GSU, and return to commercial operation. The damaged GSU was then shipped to the manufacturer, repaired, and returned to the plant, and the process took well over one year. Given the millions of dollars of investment required to purchase a GSU, many EGUs do not maintain a spare which means that a GSU failure at one of those plants would potentially create a major generation shortage jeopardizing reliability for several years, assuming that a damaged GSU could be repaired. If a catastrophic mechanical failure required the replacement of a GSU, the delay could be even greater as such equipment must be specially manufactured for the specific use, and transformer production alone currently takes an average of 24 months.

In addition, nuclear generating units can experience longer than anticipated timelines for refueling and planned maintenance. A public report to the Minnesota Public Service

[89] 80 Fed. Reg. 64,877

Commission documents such an experience by Excel Energy at its Monticello facility.[90] In this case, the utility had estimated that the work would take 85 days to complete, but ended up taking 138 days.

Given these types of experiences, APPA recommends that EPA extend the time available for the RSV to allow for up to 150 days.

APPA is aware that in the Section 111(d) Rule, EPA states that, for reliability events of longer than 90 days, EGUs can either provide allowances or ERCs to cover the associated increased emissions, or seek EPA approval of a revision to the state plan. As noted above, however, in the first option, allowances or credits may not be available, or they may be exorbitantly priced. With respect to state plan revisions as a remedy, there are several potential problems. First, it may not be possible to get the necessary agreement or approval among the relevant parties within the state on what that modification would be. Legislation may be required, for example. In addition, for overall compliance purposes, modification of the state plan may be sub-optimal compared to a simple extension of the RSV time allowance.

3. EPA Should Delineate the Process Under Which NERC and FERC Coordinate and the Respective Roles of Involved Entities.

The proposed Section 111(d) Rule contained no RSV or similar provision. Thus, APPA and other commenters had no opportunity to provide input on important elements of the RSV as envisioned by EPA and included in the final Section 111(d) Rule. While the RSV is a welcome addition, unfortunately its workability and effectiveness are undermined by a lack of clarity with respect to both important terms and provisions, as well as the roles of key participants. In addition, some of the specific requirements of the RSV are likely to be too inflexible when

[90] https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bD9493F72-EBCF-4FE0-A203-CCC50B6D55F7%7d&documentTitle=201310-92719-04.

applied in actual events triggering the RSV, especially weather-related events. EPA should modify the RSV to address these issues.

Provisions such as "emergency situation that threatens reliability" are not defined, for example. Further, in the required notification procedures, it is not clear what entity is the "state" for purposes of requesting application of the RSV. EPA should clearly define these terms and procedures.

In addition, with respect to the notification procedures, it is quite possible that the 48-hour requirement for the initial notification is unrealistic. In the case of a severe weather event over a substantial area, communications channels among key entities, including state agencies and utilities, may be unavailable or significantly impaired during the initial response period. Key personnel may not be available. Other priorities may prevail. EPA should clarify how these issues would be resolved and provide additional flexibility in its requirements to prevent a disqualification of the RSV if it is truly needed.

The Agency should also further clarify the roles of the various entities responsible for electric system reliability in the RSV. EPA uses the terms reliability coordinators and planning authorities interchangeably. There is no mention of the North American Reliability Corporation (NERC) or the NERC regional representatives. EPA should provide maximum flexibility in allowing states and EGUs to provide the required supporting documentation from entities with the legal responsibility to ensure system reliability.

4. EPA Must Conduct a Resource Adequacy and Reliability Analysis for the Proposed Trading Plan Rule.

EPA must perform a new resource adequacy and reliability analysis that evaluates the effects of the Proposed Trading Plan Rule itself. In the Proposed Trading Plan Rule, the Agency cites the Resource Adequacy and Reliability Analysis TSD (Reliability TSD) that it

created for the Section 111(d) Rule.[91] The Reliability TSD based its analysis of resource adequacy and reliability in large part on a state's ability to design its own plan and the availability of a reliability safety valve. [92] However, neither the proposed federal plans nor the model trading rules, include these measures of state flexibility *or* the reliability safety valve. It is unreasonable for the Agency to base its assumptions about reliability and resource adequacy on circumstances that do not exist under the Proposed Trading Plan Rule and EPA must create a new resource adequacy and reliability analysis that analyzes these factors under the specific circumstances posed by the Proposed Trading Plan Rule.

EPA Has Not Provided Adequate Mechanisms for Preventing Market Manipulation.

EPA is proposing that affected EGUs in any state covered by a federal plan could trade compliance instruments with affected EGUs in any other state covered by a federal plan or a state plan meeting the conditions for linkage to the federal plan.[93] Implementation of a federal plan is likely to entail trading of ERCs or allowances between affected EGUs in states, in different regions, and with different market structures.

Based on experience with other allowance trading programs (i.e., the Acid Rain Trading Program and Regional Greenhouse Gas Initiative (RGGI)), it can be expected that entities other than owners of affected EGUs will also participate as brokers or traders of ERCs or allowances, or offer tools that allow affected EGUs to hedge against price increases or volatility, such as futures or forwards contracts, swaps, or put or call options.[94] Trends in energy and other commodity markets show that there is also the potential for investment firms and other financial

[91] 80 Fed. Reg. at 64,982
[92] Technical Support Document: Resource Adequacy and Reliability Analysis, August 2015 at 1-2
[93] 80 Fed. Reg. at 64,976.
[94] *Potomac Economics*, Annual Report on the Market for RGGI CO_2 Allowances: 2014 (May 2015), p. 14-16

entities with no direct relationship to affected EGUs or their owners to trade in these instruments.[95]

APPA supports the availability of tradable instruments as a means of compliance with the emission reduction requirements, but we also have concerns about the competitiveness of ERC and allowance markets and potential for market manipulation. The Proposed Trading Plan Rule acknowledges that "[a] transparent and well-functioning allowance or ERC market is an important element of a mass-based or rate-based trading program."[96] But "the agency believes that the ERC market and the allowance market would be competitive," and based on its experience with emissions trading in the power sector, "the potential or likelihood of market manipulation is fairly low."[97] The factual basis for the Agency's belief is not described, even in outline. Neither does the Proposed provide a reason for concluding that the experience with much less ambitious and smaller prior trading regimes is informative here.

The Proposed Rulestates that "EPA is evaluating the options for providing oversight of the allowance or ERC markets," which "could include engaging with other federal and state agencies as appropriate, and potentially with third parties, in conducing market oversight."[98] But the Proposed Rule contains no details and does not describe what "options" EPA is "evaluating," and thus no basis for believing that they will prove sufficient.

APPA does not share the Agency's belief that the electric industry's market structure, existing institutions, and existing regulatory oversight mechanisms will ensure transparent and competitive ERC and allowance markets. This section describes some possible market

[95] Saule T. Omarova , The Merchants of Wall Street: Banking, Commerce, and Commodities, Minnesota Law Review, Vol. 98, 2013, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2180647#
[96] 80 Fed. Reg. at 64,977.
[97] *Id*.
[98] *Id*.

manipulation scenarios drawn from past experience and describes further steps the Agency can and should take in the final Trading Plan Rule to prevent or deter manipulation of ERC and allowance markets.

5. Potential Types of Market Manipulation That Could Occur in ERC and Allowance Markets

The discussion below illustrates some possible types of manipulation that may occur, but is not meant to be an all-inclusive description.

a. Financial Entity Actions.

Over the past four years, FERC's Office of Enforcement has assessed $875 million in civil penalties and $270 million in disgorgements against financial entities for manipulation of the wholesale electricity markets,[99] representing 91 percent and 94 percent respectively of all civil penalties and disgorgements for violations of the electricity market anti-manipulation rule.[100] Most of these financial entities do not serve electricity load and most do not even generate electricity. Many of these cases involved an entity taking a loss in one market, often a physical energy market, as a means to obtain a greater benefit in a financial position, such as a swap or financial transmission right.

The availability of ERCs and allowances represents another market in which financial entities could seek profit opportunities to the detriment of affected EGUs seeking to purchase these instruments for compliance purposes. For example, as has occurred in the energy markets, financial swaps may be arranged that are based on ERC or allowance prices, resulting in an incentive to trade allowances or ERCs in a manner that produces benefits for the swap, but could

[99] Compilation of data obtained from Office of Enforcement, Federal Energy Regulatory Commission annual Reports on Enforcement.

[100] The Energy Policy Act of 2005 (EPAct05) amended the Federal Power Act by adding prohibitions on the manipulation of wholesale electricity markets ("anti-manipulation rule") and the submission of false information.

adversely affect purchasers of such compliance instruments. Examples from the energy markets provide an indicator of the potential for such actions. In two separate cases, FERC's Office of Enforcement found that Barclays Bank PLC and Constellation Commodities Energy Group traded in the physical energy markets in a manner that would benefit financial positions indexed to energy prices, but that also drove up costs to consumers. The estimated profits were $35 million for Barclays and $110 million for Constellation.[101] These entities do not generate electricity or serve load.

Such financial entities are different from brokers or other third-party entities that may be providing a useful service in creating platforms for trading or hedges, such as futures contracts. Financial entities participate in markets solely for the purpose of seeking opportunities to increase their earnings through financial instruments, yet their actions directly influence prices and market conditions.

b. Merchant Generator Actions.

Merchant generators are not owned by a vertically-integrated utility and their prices and earnings are not regulated by a state commission. Such entities are largely located in restructured wholesale markets operated by RTOs, where wholesale prices are subject only to minimal regulation by FERC. The regions characterized by both retail restructuring, where the investor-owned utilities no longer own generation, and wholesale market restructuring, include

[101] *Federal Energy Regulatory Commission* ,Order Assessing Civil Penalties, Barclays Bank PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith, Docket No. IN08-8-000 (July 16, 2013), *Federal Energy Regulatory Commission*, Order Approving Stipulation and Consent Agreement, Constellation Energy Commodities Group, Inc., Docket No. IN13-17-000 (October 18, 2013)

the mid-Atlantic and Northeast, where the wholesale markets are operated by PJM, ISO–NE,) and NYISO.[102]

These merchant generation owners will by their nature structure their actions in the wholesale electricity markets to maximize their earnings, and as such, have a financial incentive to purchase and sell allowances and ERCs in a manner with the goal of profit maximization in the energy markets. For example, a merchant generator may decide to "economically withhold" allowances by pricing them out of the market to restrict generation from other EGUs who may require such ERCs or allowance, and by restricting supply, produce an increase prices.

Another possible scenario may occur where a merchant generator owns multiple EGUs within its fleet across multiple states, as is often the case, and sells an ERC or an allowance from one EGU in the fleet to another at a very high price. Such an action could be used, for example, in PJM to provide a cost-based justification for a high offers into the energy market. In PJM, FERC recently approved an increase in the cap on offers to sell into the energy market from $1,000 to $2,000 per MWh with offers greater than $1,000 required to be cost-based.[103] The plant purchasing high cost allowances could use it to justify a high priced offer with the result being a dramatic increase in the locational marginal price paid to all other generators, including the rest of the fleet under ownership by that company.

While it is not possible to predict the extent to which the above and other potential market manipulations will occur, the potential for such behaviors is sufficient to justify some

[102] ISO stands for "Independent System Operator," a term that is used interchangeably with Regional Transmission Operator.
[103] *Federal Energy Regulatory Commission*, Order Accepting Proposed Tariff and Operating Agreement Revisions, PJM Interconnection, L.L.C., Docket No., ER16-76-000 (December 11, 2015)

protections against the resulting price spikes and volatility in the ERC and allowance markets. These recommendations are described below.

6. Potential Remedies and Program Enhancements to Prevent Market Manipulation.

a. Greater Transparency of Trading and Allowance or ERC Price Data.

APPA recommends that EPA, at a minimum, require the reporting of all trades by entity type, relationship to affected EGU (e.g., self, broker, or none), length of holding of allowance or ERC, and the price at which the instrument was traded. Such information will allow any interested party to investigate whether there are anomalous patterns in prices, the degree of and frequency of price spikes, overall price volatility, and the relationship between such pricing data and ownership types. Having such information available to the public could potentially provide a deterrent to entities seeking to engage in market manipulation.

EPA is not proposing a sufficient level of publicly available data to allow for tracking such potential manipulation. In the proposed rule, EPA states that the Allowance Tracking and Compliance System (ATCS) for ERCs and allowances will provide to the public a record of ownership, dates of transfers, buyer and seller information, origin of ERCs, serial numbers, and ERC type. For ownership information, holdings of ERCs and allowances would be identified as being in "compliance accounts (i.e., accounts for affected EGUs or general accounts (i.e. accounts for all other entities such as companies and brokers)."[104] But for both ERCs and allowances, EPA notes that price information will not be included in ATCS because "private parties (e.g. brokers) are in a better position to obtain and disseminate timely, accurate price

[104] 80 Fed. Reg. at 64,997 and 65,029

information than the EPA" and that "the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices."[105]

APPA disagrees; however, as the timeliness of the price information is not the only benefit to making price data publicly available. Even with a time lag, tracking and reporting of prices would allow for adequate monitoring of the market and deterrence of market manipulation. Collecting price data should not be difficult given the other ATCS reporting requirements. EPA can simply require that as an entity reports a trade and serial number, it also records the price at which the instrument was sold. Without such a requirement, price data can be difficult to obtain. A January 2014 Congressional Budget Office (CBO) report notes that: "trading of SO_2 allowances is largely done in private bilateral negotiations between two parties (i.e., over the counter) and not on centralized, transparent exchanges. For that reason, spot price data for SO_2 allowances tend to be proprietary and difficult to obtain."[106]

Under RGGI, the market monitor, Potomac Economics, issues annual reports on both the prices in the auctions and in the secondary market, where futures contracts and other options are offered by financial entities. Such price and other data is recorded regularly in RGGI's CO_2 Allowance Tracking System (COATS).[107]

As noted above, a necessary element for ensuring market integrity and preventing market manipulation is a well-funded and vigilant oversight mechanism. Market monitoring is also important to building confidence in a trading system since the value of allowances will not erode due to illegal or unsanctioned activity.[108] EPA should ensure that monitoring is an ongoing part

[105] 80 Fed. Reg. at 64,998 and 65,030
[106] Claudia Hitaj, Economic Research Service, United States Department of Agriculture, and Andrew Stocking, Congressional Budget Office, Market Efficiency and the U.S. Market for Sulfur Dioxide Allowances (January 2014)
[107] Potomac Economics, Annual Report on the Market for RGGI CO_2 Allowances: 2014 (May 2015)
[108] Washington State Department of Ecology, Economic Analysis of a Cap and Trade Program (November 11, 2008)

of the administration of a federal plan and should explain in the final rule what role state and federal agencies will play in such monitoring. If it appears as if there is collusion among bidders or other market manipulation, EPA should allow states to make adjustments to the program including modifying the auction design or creating additional market and price transparency mechanisms. A state or regional monitor should also be allowed to look for imbalanced positions among participants, or other signs of market manipulation as needed.

7. A Price Safety Valve Should Be Implemented.

Along with price transparency, a price safety valve is needed to ensure that the types of trading programs that EPA envisions in its Proposed Rule avoid creating unnecessary compliance burdens for EGUs. A price safety valve, if properly implemented, has the potential to help act as an additional safeguard against market manipulation.

EPA states that it has significant experience with emissions trading programs.[109] In the emissions trading programs the Agency cites, many sources complied with the allowance limitations created by adding control technology. However, in the case of the Section 111(d) Rule, no demonstrated (commercially available) CO_2 reduction technology exists for EGUs. Further, there is little evidence that regulated entities change their patterns of behavior based on short-term changes in allowance prices.[110] Given the clear provision for the consideration of cost in the Section 111 (d) Rule, EPA should provide the option of a price safety valve to help states abate short-term increases in allowance prices that do not significantly contribute to additional compliance. These types of temporary price spikes only result in increased prices for consumers and windfall profits for allowance holders. EPA has an obligation to ensure that transient

[109] 80 Fed. Reg. at 64,968
[110] *Alexander E. Farrell, University of California, Berkeley* Emissions Markets – Characteristics and Evolution, (March 2005) CEC-500-2005-024

compliance price spikes can be mitigated by cost containment mechanisms allowed under its federal plan.

Many states have come to the conclusion that price safety valves are reasonable in their promotion of renewable energy through Renewable Portfolio Standards (RPS). EPA cites RPS standards extensively as justification in its Section 111(d) Rule rulemaking, but does not include the price safety valve-like elements of these standards in its Proposed Rule. APPA believes that the mechanisms used by states to control RPS costs specifically where Renewable Energy Credit (REC) markets exist should be explicitly allowed in its federal plan.

A number of states have decided to implement the equivalent of a price safety valve to ensure price stability in REC markets. These price safety valves often take the form of alternative compliance payment mechanisms. In states with restructured markets, compliance entities are typically buying "unbundled" RECs and most restructured states have payments that enable obligated entities to make a payment at a pre-established price in lieu of procuring renewables (e.g., $50/MWh).[111] APPA has argued that EPA can allow states to use alternative compliance payments in its Section 111(d) Rule.[112]

An alternative payment concept would work as a safety valve in EPA's Proposed Rule because it would essentially establish a ceiling on the cost of compliance. An example of such a concept is the proposal by the National Climate Coalition for a ceiling-price alternative compliance payment (ACP), which is a mechanism "by which a source could make a compliance payment to the state in lieu of achieving on-site reductions and allowing the state to use the funds towards energy system improvements (i.e., greenhouse gas emission reductions outside the

[111] *National Renewable Energy Laboratory (NREL)*, A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards, NREL/TP-6A20-61042 (May 2014)
[112] Comments by the American Public Power Association to EPA on Proposed Section 111(d) Rule for Carbon Dioxide Emissions, Page. 157, December 1, 2014.

source)."[113] Though this is only one method for achieving a price safety value, giving states the option to use a price safety valve under the federal plan would help EPA achieve its emissions goals more efficiently. A price safety valve would also help obligated entities avoid being forced into contracts to procure renewable generation above their reasonable long-run cost. Consumers would benefit substantially from any mechanism that dampens the potential for emissions trading markets to create short term and unproductive overpayments for emissions compliance.

Fuel switching, adding renewable generation sources, and instituting energy efficiency programs all take significant time. To mitigate temporary allowance shortage situations, which may occur in the implementation of emission trading programs, states should have the option to draw upon any emission credit or allowance reserves available if prices exceed a specified threshold. To ensure emissions goals are met, a state could reinvest the proceeds from the allowances into compliance projects at the state level. States that receive a Section 111(d) federal plan should have to ability to implement a price safety valve, to mitigate short term allowance, or credit, price spikes and further EPA's emissions goals.

8. Restrictions on Entities Buying and Selling ERCs and Allowances.

As noted above in the discussion of market manipulation, significant enforcement action has been necessary in certain energy markets to protect consumers from the behavior of entities not actually owning generation. Based on this, an important safeguard against the potential for market manipulation in ERC and allowance markets would be to restrict the participation of entities with no relationship with affected EGUs. For example, a broker or other third-party that is directly trading between EGUs, or offering futures contracts or other hedges directly to an EGU, should be permitted to buy and sell ERCs and Allowances. Yet a financial entity that

[113] *National Climate Coalition*, Comments on EPA's Proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (December 2014).

cannot demonstrate any relationship to an EGU should not be permitted to purchase and sell compliance instruments. Such a demonstration should be required as part of the registration process for the ATCS.

C. EPA Failed to Include Sufficient Details with Respect to the CEIP.

As proposed, is characterized by fundamental legal flaws that must be corrected. APPA addresses these errors below.

1. EPA's Proposed CEIP Is Seriously Flawed.

The process by which EPA proposed the CEIP and the substance of its proposal are both seriously flawed. These errors, described below, must be corrected before the CEIP can be included in any final federal plan or the model trading rules. As discussed earlier in these comments, CAA Section 307(d) establishes specific requirements for the content of proposed rules, including that the complete regulatory text and information on which it is based be available to the public. In the final Section 111(d) Rule, in the non-regulatory CEIP docket that EPA established and announced via e-mail, and even in this proceeding, the Agency has failed to satisfy these requirements. Moreover, even though EPA appears to concede that the CEIP is a part of the Proposed Trading Plan Rule and that it is open for comment in this rulemaking proceeding, the Agency has failed to provide adequate detail on the CEIP, thereby unduly limiting public comment. Therefore, EPA must develop an additional proposed rule that provides all of the necessary details on the CEIP program and allow adequate public review and comment on that proposal.

Specifically, to satisfy the requirements of the APA and CAA Section 307(d), EPA must provide: "all data, information, and documents referred to in this paragraph on which the

proposed rule relies . . . on the date of publication of the proposed rule."[114] The "documents referred to in this paragraph" are: "(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule."[115]

EPA has clearly failed to satisfy the requirements of Section 307(d) with respect to its CEIP rulemaking actions to date. The Agency has broadly sketched some elements of the CEIP and requested stakeholder input, but it acknowledges that key implementation details are still forthcoming.[116] Until those details are provided and subjected to notice and comment, the CEIP cannot properly be made a regulatory requirement.

2. The CEIP Is Too Restrictive with Respect to Renewable Energy.

EPA's Proposed Rule, which limits the categories of renewable energy (RE) projects that can qualify for participation in the CEIP, is too restrictive. According to the Proposed Rule, only projects that use wind or solar resources can receive CEIP credit.[117] Expansion of these categories would allow any kind of RE project to be eligible for allowances or ERCs under the CEIP, both from the state funds and federal matching fund. This would remove an unjustified bias against certain technologies, allow states maximum flexibility in their compliance plans, and permit new and developing technologies to compete effectively.

EPA, on the other hand, has not explained why it is necessary to restrict the CEIP to only wind and solar resources. The Section 111(d) Rule states that a "variety of considerations" went

[114] CAA § 307(d)(3).
[115] *Id*. § 307(d)(3)(A)-(C).
[116] 80 Fed. Reg. at 65,026
[117] 80 Fed. Reg. at 65,062 (proposed § 62.16231(a)(1), specifying that allowances would be awarded for metered wind and solar power); *id.* at 65,092-93 (proposed § 62.16431(a)(1), specifying that ERCs would be awarded for metered wind and solar power); *see also* 80 Fed. Reg. at 64,943 (final § 60.5737(b)(1), specifying that the CEIP applies to "RE projects that generate metered MWh from wind or solar resources").

into the development of this restriction.[118] The Agency's reasoning, however, is not supported by the record and is arbitrary and capricious. EPA has provided no specific analysis supporting its assertion that wind and solar is, in fact, essential to longer term climate strategies. Nor has EPA addressed why other forms of zero-emitting RE are not as effective at supporting a long-term climate strategy. The Agency's principal rationalization appears to be that it believes solar and wind are the most viable technologies and, thus, the most deserving of subsidies from the federal government. In implementing performance standards under CAA Section 111(d), EPA should not be making these determinations. Its focus should be environmental benefits and emission reductions, which any form of RE can provide. EPA should let the market decide which categories of RE are most viable.

The Agency should further expand the list of resources eligible for the CEIP to include nuclear units that are relicensed after the same date (January 1, 2013) for which generation from new nuclear units can qualify for ERCs during the Section 111(d) Rule compliance period. For such relicensed units, CEIP credits (ERCs or allowances) would be earned after a specific date (e.g., October 23, 2015, as recommended in the following bulleted comment), beginning on the date that relicensing occurs and ending on the date that compliance with Section 111(d) Rule emissions limitations begin (January 1, 2022). This would recognize that, without relicensing, an existing nuclear unit may not operate beyond the expiration date of its then-current license. Nuclear units operate at high capacity factors, and their electricity production cannot be replaced by intermittent generation sources, such as wind or solar energy; it is likely that the capacity and energy replacement for a nuclear unit with an expired license would be one or several coal steam generating units and/or NGCC, with significant CO_2 emissions resulting.

[118] 80 Fed. Reg. at 64,831

The Municipal Electric Authority of Georgia (MEAG), an APPA member, is a co-owner of two existing nuclear units, Plant Hatch 1 and 2, which received new licenses in 2014 and 2017, respectively. The licenses for these units would have expired in 2014 and 2018, respectively. Providing CEIP eligibility for these units will recognize the continuation of emissions-free electricity production in the same manner that other emissions-free resources are recognized in the CEIP proposal.

EPA should further extend recognition of relicensed nuclear units as emissions-free resources by revising the Proposed Trading Plan Rule criteria for nuclear ERCs during the compliance period to include units relicensed after the start of the CPP compliance period. APPA further supports comments by MEAG regarding the eligibility of new nuclear to receive early action credits (ERCs or allowances) under the CEIP.

3. The Pool of Allowances or ERCs Should Not Be Taken from State Budgets.

EPA should amend the CEIP to create a true incentive program for early action to reduce emissions, similar to other EPA programs that have been successfully implemented in the past. Most critically, that involves transforming the CEIP into a program that brings new allowances or ERCs into the formula for compliance. As proposed, the CEIP is not a true incentive program, because it removes allowable emissions from the state budgets and thereby reduces some of the flexibility otherwise offered by a trading program. Because the state portion of the emission allowances or credits awarded in the CEIP come from the state's emission budget, the CEIP itself may make it more difficult for some coal- and natural gas-fired EGUs to meet their compliance obligations. The CEIP is also unlike other incentive programs because it does not specifically incentivize early action from entities regulated by the Section 111(d) Rule. Indeed, anyone interested in investing in RE or EE projects could receive CEIP incentives.

To correct these shortcomings and create a more effective early action program, EPA should modify the CEIP to more closely resemble prior incentive programs, which gave added flexibility to regulated sources and provided a true incentive to act early. For instance, the Acid Rain Program under Title IV of the 1990 CAA Amendments, created a banking program that awarded early emission reduction actions that were directly targeted at the regulated EGUs. The NOx SIP Call's Compliance Supplement Pool, on the other hand, and a similar program under EPA's Clean Air Interstate Rule, created extra allowances, in addition to those included in state budgets under those programs, to reward early actions. These sorts of programs would be much more effective at encouraging early action, reducing emissions, and increasing compliance flexibility than the proposed version of the CEIP.

In sum, if the CEIP is truly intended to incentivize early action, it must be revised to provide allowances or ERCs that would not otherwise be available. Adjusting the allowance or ERC pool to subtract the allowances awarded through the CEIP introduces significant uncertainty and is inconsistent with prior EPA early action incentive programs.

4. EPA Should Include a Mechanism for Recognizing Emission Reductions from RE[119] Projects That Commenced Construction After Promulgation of the Section 111(d) Rule.

The Proposed Trading Plan Rule includes a provision to encourage early action in the creation of the CEIP.[120] However, the CEIP fails to consider many RE projects that are currently in the planning and development phases. There are hydropower and geothermal facilities that could increase capacity at existing EGUs within a similar two-year construction window. As

[119] Throughout these comments, APPA refers to "RE" to maintain consistency with EPA's preferred terminology. EPA should recognize, however, that the concept of RE under the Section 111(d) Rule and the Proposed Trading Plan Rule should be expanded to include all forms of zero-emitting generation.
[120] 80 Fed. Reg. 64978

proposed, the CEIP delays the creation of allowances and ERCs, until 2020 and/or 2021, thus hampering early CO_2 emission reduction opportunities, as exemplified by a recent announcement by an investor-owned utility, to delay for an unspecified period of time, the development of a 15 MW solar project.[121] The short two year time period when allowances and ERCs can be generated under the CEIP may result in RE project developers becoming overwhelmed with installation orders which cannot be fulfilled due to supply chain limitations and lack of available skilled labor resulting in limited investments and delays in installation. APPA would suggest the CEIP be allowed to create credits for RE projects that generate MWh or create demand reductions for four years instead of two years to alleviate installation bottlenecks.

The design of the Proposed Rule and CEIP suggests EPA is seeking a way to incentivize final Section 111(d) state plan submittals before September 2018. Projects become eligible for CEIP credits only if they commence construction after a final state implementation plan is submitted in the project's host state. EPA allows plans to be finalized as late as September 2018. Because of the value of CEIP credits, project developers may encourage states to finalize plans as soon as possible in order to open CEIP eligibility to a greater number of projects. Early state plan finalization may give affected sources additional time to plan for compliance and lower the regulatory uncertainty around the implementation of the Section 111(d) Rule. APPA recommends the CEIP grandfathers all RE projects which have commenced construction since the Section 111(d) Rule was finalized and move the start date of the CEIP to align with a state's initial Section 111(d) state plan submittal.

[121] Source: http://www.stltoday.com/business/local/ameren-suspends-plans-for-huge-solar-farm-along-i/article_36207a6d-2909-50ac-9dd5-c7e64a33e82b.html.

D. EPA Has Ignored Considerable Evidence That the Proposed Federal Plan Will Create Stranded Asset Problems.

It appears that compliance with the Section 111(d) Rule will lead or contribute to premature retirement of a significant number of U.S. coal-fired power plants; premature in the sense that the plants will be shut down before the end of their useful lives. This will create economic losses, in the form of forgone economic value, for electric utilities, their customers and local communities in many states. In its May 2015 *Analysis of the Impacts of the Clean Power Plan*, EIA estimates that, over the 2020-2040 period, between 50 and 60 GW of coal-fired generation will be retired as a result of the Section 111(d) Rule.[122] The notion that economic losses will result from premature retirement of power plants is inescapable because useful life is properly thought of in terms of an asset's ability to yield on-going economic value, and this creates a version of stranded costs in the following sense.

In the public power sector, a utility's generating assets are, in effect, owned by its customers, with the government entity acting as their agent. While the utility actually procures the assets, and is the legal owner, the economics of ownership, both positive and negative, redound to the customers. Both the costs and benefits of asset ownership are conveyed to customers through their electric rates. For example, if a utility purchases a coal plant, the costs of ownership (purchase price, financing cost, and on-going operation and maintenance) will be directly passed through in the electric rates, but if the plant is economic, electric rates will, over the life of the plant, be lower than they would have been if the utility had met the customer's ongoing power needs through market purchases or acquisition of alternative resources. So, customers recoup their investment in a generating asset through reduced electric rates over the

[122] Note that the analysis was released before the final Section 111(d) Rule, which calls for even greater emissions reductions. Thus, the results are probably low-end conservative.

asset's useful life. But, if the plant ceases operation during its economically useful life, the investment becomes stranded when the benefit stream is truncated.

It is important to realize that stranded costs relate to the economic value of an asset to customers over its useful life, and not to the means of financing it. Since public power utilities are not-for-profit, their assets are financed primarily with long-term debt, and it is sometimes mistakenly thought that an asset's useful life is directly related to its debt repayment servicing schedule. This misconception might lead some to conclude that retirement of an asset after the debt has been repaid somehow mitigates the economic losses attendant with its retirement, thus implying that the stranded cost problem goes away after the debt has been repaid. But this is not the case. The economic losses borne by customers, and the level of stranded costs, will be same irrespective of the debt servicing schedule.

Stranded cost losses will vary widely across regions and utility jurisdictions. On average, across the public power sector, approximately 40 percent of total electric output is produced from coal, with much higher percentages in some situations. This clearly constitutes a significant investment for these public power utilities and their customers, undertaken in anticipation of realizing long-term benefits over the useful lives of the coal plants, and premature shutdown of these facilities will harm public power customers and their communities.

Concern over this is heightened in those cases where large recent expenditures, undertaken to comply with other environmental regulations, become stranded by compliance with the Section 111(d) Rule. For example, in earlier comments on the proposed Section 111(d) Rule, APPA cited the case of Missouri River Energy Services (MRES), which as a part owner of the Laramie River Station (LRS) in Wyoming, stands to realize a stranded cost burden of about $125 million related to the recent installation of Selective Catalytic Reduction (SCR) equipment

on all three LRS units, if LRS closes as a result of compliance with the Section 111(d) Rule.[123] While situations like this seem particularly unfair, it is important to keep in mind that whether the investments were made recently or not, the premature retirement of economic coal plants will result in significant economic losses to public power customers and communities.

1. EPA Does Not Understand the Power Supply Diversity in Public Power Utilities and Resulting Impacts to Customers.

EPA's Proposed Trading Plan Rule (as well as the Section 111(d) Rule) does not adequately consider the diversity of methods that individual public power electric utilities use to produce or receive the electricity that they supply to retail consumers. In particular, the Proposed Trading Plan Rule does not consider the disparate impacts to individual public power electric utilities.

In many states, public power electric utilities are a function and a service of individual communities/municipalities (individual cities or towns), rather than area, regional, or statewide entities. There can be dozens of separate public power electric utilities within a single state, and each is a separate retail electricity supplier.

The approach to how electricity is generated at or for each public power electric utility varies—e.g., the utility may generate its own electricity, it may contract with another party to generate the electricity, it may be a partial owner of a generating facility, or it may use other methods and combinations. The process may be determined by the individual utility, by prescribed state statute, or conducted by other means.

For example, one of APPA's members, MEAG, located in the state of Georgia, is a not-for-profit entity created by Georgia statute to provide wholesale electricity to retail public power

[123] *Comments of the American Public Power Association (APPA) on EPA's Section 111(d) Proposed Rule for Carbon Dioxide Emissions from Existing EGUs EPA-HQOAR- 2013-0602*, pp. 172. December 14, 2015.

utilities in Georgia through binding long-term contracts. Retail consumers in Georgia are served by 97 separate retail distribution utilities--53 public power electric utilities, 43 cooperatives, Georgia Electric Membership Corp. (EMCs), and one investor-owned utility. Forty-nine of the 53 retail public power utilities in Georgia receive wholesale electricity from MEAG. These 49 public power communities represent a population of about 700,000 citizens; many of the 49 communities are characterized by higher than average poverty levels. MEAG has a diverse overall energy mix of existing nuclear, coal, and NGCC resources, and is a partial owner the under-construction Plant Vogtle 3 & 4 nuclear project.

Each of the 49 communities, through their local authority and decision making processes, has the ability to provide for its local electric system needs through MEAG by purchasing the output and services from one or more electric generating units. This process has been in place for more than 40 years. Each community does this by contracting for specific percentage shares of specific generating unit projects, depending on the community's need for future capacity and the timing of that need. Purchase contracts are binding and commit each community to a long-term contract to pay its respective obligation share of the units' costs. The costs include debt service, along with operation and maintenance costs, including the debt service, operation, and maintenance costs MEAG has incurred to retrofit the units to meet other state and federal environmental requirements. MEAG's current contracts with its communities extend at least through 2054.

Each of the 49 public power communities has its own unique energy mix of resource types (e.g., coal, natural gas, nuclear, etc.), and each community would be affected differently by the Proposed Trading Plan Rule. For example, some communities have a substantial amount of NGCC capacity and associated energy, while other communities have no NGCC capacity. Some

communities are very dependent on coal generation, while others are less dependent. Some communities have a substantial commitment to the under-construction Plant Vogtle Units 3 & 4 nuclear project, while others have no commitment. Compliance with the Section 111(d) Rule via Proposed Trading Plan Rule the will likely require the elimination or significant underutilization of many communities' coal-fired power plant capacity, stranding those assets while long-term contractual commitments remain to pay the remaining debt on that capacity. Many communities will also be required to pay for the costs of alternate electricity, essentially paying twice for their electricity supply. This situation is repeated in other states, for other public power communities.

E. EPA Must Provide Greater Safeguards for Small Entities.

APPA participated in the Small Business Advocacy Review Panel (SBAR Panel) process convened to review the planned Proposed Rule. The unusually short timeframe in which the SBAR Panel met did not provide Small Entity Representatives (SERs) with sufficient time to offer meaningful comment and participation in the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA) process. APPA believes EPA did not provide sufficient materials to convene this SBAR panel. The Agency did not provide panel members with information on the potential impacts of this Proposed Pule, nor did the Agency provide SERs with the necessary information upon which to discuss alternatives and provide recommendations to EPA, as required under SBREFA.[124]

APPA's concerns are further amplified in recent comments submitted to the Agency by the Small Business Administration Office of Advocacy regarding EPA's Proposed Trading Plan

[124] Comments of the American Public Power Association (APPA). Small Business Advocacy Review Panel Comments on EPA's Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generating Units Constructed on or Before January 8, 2014, May 28, 2015.

Rule.[125] Prior to the conclusion of the SBRFRA process, the Agency submitted the Proposed Rule to the Office of Management and Budget for review on July 2, 2015. The SBREFA panel signed and submitted its report with recommendations to the EPA Administrator on July 31, 2015. Subsequently, EPA signed the proposed rule on August 3, 2015. The sequence of events is troubling and demonstrates the SBREFA process was meaningless and offered no true opportunity for consultation with the small entities.

EPA should include a mechanism that would provide small entities with more time for compliance. The Section 111(d) Rule did adjust several state CO_2 emission goals and moved the initial compliance deadline from 2020 to 2022, but these modifications do not fully address the compliance timeline concerns of small entities. The stated goal of the Section 111(d) Rule is to "spur private investments in low-emitting and renewable power sources"[126] (gas-fired NGCC, nuclear, and renewables such as wind and solar) to replace generation from CO_2-intensive power plants (i.e., coal). Compliance will require the construction of new low-emitting (gas-fired NGCC) and zero-emitting (nuclear and renewables) power plants to replace coal-fired generation.

Public power utilities are accountable to consumers, city councils, and state and local governments when making decisions regarding electricity generation resources. Thus a federal plan must take into consideration the case-by-case nature of the planning process of public power utilities, which may require additional time to make generation investment decisions. For example, NERC recently concluded that utility-scale projects over 50 MW require 40 months for

[125] Comments from the Small Business Administration, Office of Advocacy on EPA's Proposed " Federal Plan Requirements for Greenhouse Gas Emissions From Electric Generating Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations" (Docket No. EPA-HQ-AOR-2015-0199), December 21, 2105.

[126] EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, Federal Register June 18, 2014, page 34,833.

a wind project and a solar project would take 37-42 months.[127] Longer lead times are necessary for planning and infrastructure development, as electric utilities shift to lower CO_2 emitting resources.

1. EPA Must Include a Mechanism to Allow Individual Utilities More Time for Compliance.

In the Proposed Trading Plan Rule, EPA specifically acknowledges that some EGUs—and small entities like APPA's members, in particular—may need more time than the current Section 111(d) Rule provides to come into compliance with its requirements.[128] To that end, EPA asks for comment on "whether it would be possible to grant, on a case-by-case basis, certain affected EGUs, particularly small entities, additional time to come into compliance," and further requests "additional input from the public as to the design of such flexibility that would be compatible with the emission guidelines and a federal plan that implements a trading system."[129]

Section 111(d) and EPA's implementing regulations for all Section 111(d) rules already provide the Agency with authority to make these kinds of adjustments to compliance obligations on case-by-case basis. Under 40 C.F.R. § 60.27(e)(2), EPA has authority to grant requests by individual facilities that seek "less stringent emissions standards or longer compliance schedules" than would otherwise be required by a federal Section 111(d) plan. In the Proposed Trading Plan Rule, EPA proposes—without explanation in a footnote in an unrelated section of the proposal—to remove 40 C.F.R. § 60.27(e)(2) for purposes of the Section 111(d) Rule. As an initial matter, EPA has not provided adequate notice of this proposed regulatory change;

[127] North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I", April 2015, page 37 at http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[128] 80 Fed. Reg. at 64,981
[129] *Id*.

therefore it cannot be finalized. More substantively, EPA has not provided a basis for removing the availability of this provision. As it does throughout the Proposed Trading Plan Rule when dismissing statutory or regulatory requirements, EPA merely asserts that the flexibility provided by a trading program obviates the need for any variances in stringency or compliance deadlines.[130] This assertion, without any analysis demonstrating that it is a realistic conclusion, is not an adequate basis for a regulatory change and would seem to be undermined by EPA's own request for comment on this issue.

Regardless, 40 C.F.R. § 60.27(e)(2) is a regulatory response to the *statutory directive* that EPA, in applying any Section 111(d) standard of performance to an EGU, evaluate its remaining useful life and other relevant factors and make adjustments as appropriate to the applicable requirements. As such, the Agency has no discretion to discard this regulatory provision without, at the very least, developing an alternative approach to addressing this statutory requirement. For that reason, APPA requests that EPA make no changes to the existing 40 C.F.R. § 60.27(e).

APPA also requests that EPA provide guidance to help EGUs understand how they may meet the criteria of 40 C.F.R. § 60.27(e) in order to obtain appropriate relief. To assist in the proper implementation of any federal plan under the Section 111(d) Rule, the Agency should provide additional directions to assist EGUs in understanding what would constitute a reasonable showing that a variance under 40 C.F.R. § 60.27(e)(2) is warranted.

If EPA insists on making changes to 40 C.F.R. § 60.27(e)(2), it should include additional mechanisms for relief in any final federal plans and the model trading rules for those facilities that cannot meet the rule's emission standards or compliance deadlines. EPA could, for instance,

[130] 80 Fed. Reg. at 64,983 n.36.

create such a provision that is applicable only to small entities. In such a case, APPA would recommend that the Agency retain the SBA's definition of small entities.[131]

The requirements of the Section 111(d) Rule, if applied inflexibly, could be devastating for EGUs, especially those owned and operated by small entities with few compliance options available to them. EPA must obey the CAA's direction that it take remaining useful life and other factors—such as cost, practicability, and time for compliance—into account when applying standards to individual EGUs.

F. Comments on EPA's Alternative Compliance Pathway for Units That Agree to Retire Before a Certain Date TSD.

EPA proposes to apply the Alternative Compliance Pathway only to units under a mass-based plan, but the TSD contemplates application under a rate-based plan as well. APPA supports the notion of an Alternative Compliance Pathway under a mass- and rate-based federal plan for all steam units that agree to retire by December 31, 2029, or have operated for fifty years after their date of initial commercial operation and agree to take an enforceable emission limit. The Alternative Compliance Pathway offers affected EGUs flexibility and certainty in determining the appropriate glide path for continued operation, while assuring states meet their overall emission goals.

1. There Are Serious Flaws in the Alternative Compliance Pathway.

EPA proposes to remove the EGU from the trading program and institute a mass-based standard that is "unit-specific and is proposed to be the 2012 generation for the unit multiplied by the corresponding rate-based standard for the unit in the compliance period. This will give a mass value for the year and would be multiplied by the number of years in the compliance period

[131] Small Business Regulatory Enforcement Fairness Act of 1996, Pub. L. No. 104-121, 110 Stat. 857 (codified at 5 U.S.C. § 601 et seq.).

to give the standard for that compliance period."[132] EPA does not specify what it means by "compliance period," but the mass value should be multiplied by the number of years in the interim period (i.e., January 1, 2022, to December 31, 2029).[133] If a retiring unit does not emit its assigned mass value before retirement, the remaining mass value should be calculated back into ERCs and distributed to the retiring EGU.

EPA should not limit its calculations solely to the 2012 historical generation baseline. The 2012 baseline may not be indicative of a unit's historical generation. To the extent that generation during 2012 is not reflective of a unit's typical operations, units should have the opportunity to present more realistic data or information to the Agency and have an alternative baseline established.

Assuming that a unit is exempt from the requirement to hold allowances or credits to cover its emissions for the entirety of the interim period (January 1, 2022, through December 31, 2029), an alternative compliance path will provide a greatly needed alternative for small entities and reduce stranded costs. Designed properly, an alternative compliance pathway will also lead to greater emissions reductions by providing an "off ramp" for communities that are interested in transitioning from their current generation assets to lower- or zero-emitting generation resources.

APPA understands that for this alternative compliance path to work, a generating unit would need to accept an enforceable unit-level CO_2 emission limit, as well as an enforceable commitment to retire on or before December 31, 2029. However, the allocations/credits that the unit receives should be purely for accounting purposes as it relates to the enforceable emissions

[132] Alternative Compliance Option Technical Support Document (TSD) at page 2.
[133] *Id*.

limit. The unit should not have to be allocated under the general allocation approach, or any approach, because EPA is proposing the unit not be allowed to trade. This effectively takes the unit out of the state plan and makes it a standalone entity with a bank of emissions based on historical generation. By accepting a rate with a bank of emissions equivalent to that rate over the number of remaining years (on or before December 31, 2029), the unit should be in compliance as long as it has remaining allowances to cover its emissions.

That bank should be based on historical generation data for at least three years (2010 - 2012 or the most recent three years of plant operation if no data is available) to calculate the unit's compliance allowance supply. In this case, the interim compliance period and state plan are not relevant because the plant agrees to retire on or before 2029 and will not emit more than the allowances equivalent to its emission rate over the sum of the years it has left before retirement.

For entities that choose to use this option, EPA should not implement a rate that is more stringent than the Section 111(b) new plant standard of 1,400 lb CO_2/MWh-g, and should allow states to set higher rates if they so choose as a part of their state planning process. The approach of setting the rate based on a maximum of the Section 111(b) new plant rule, is highly aligned with a fundamental CAA legal precedent, which can be summarized as follows—if any unit meets or beats the emissions rate of a new plant, then it is in compliance. This is especially true since there can be no leakage with plants that agree to retire.

EPA should make the calculation of the alternative compliance path simple and effective. For example, a 100 MW EGU with an emissions rate of 2,100 lb. CO_2/MWh-g would accept an enforceable retirement date on or before December 31, 2029, be excluded from all state plan

activities, and be allocated the equivalent of Section 111(b) new plant allowances by rate for the interim compliance period. In this case, if a plant had historical generation (2010 -2012) equivalent to 5,000 hours a year at full output (or a 62 percent capacity factor), it would equal 500,000 MWh/year of generation as a baseline. For compliance, the unit would then receive 500,000 MWh x 1,400 lb. CO2/MWh-g x 8 years for allowances to account for the compliance period until its enforceable retirement. Using this scheme, the unit would be limited to a maximum of 5,600,000,000 lbs. CO_2 in its remaining life (during the eight year compliance period) from its historical baseline and of 8,400,000,000 lbs. that might otherwise be expected until its retirement date. This constitutes a simple and effective emissions-reduction scheme.

No matter how the EGU runs over the compliance period, this ensures that the EGU in our hypothetical example reduces emissions by 33 percent over the compliance period (retirement on or before December 31, 2029). This approach is straight forward, adaptable, and ensures the state plan goals are met while preserving some economic value. APPA further believes the initial showing of interest for the alternative compliance pathway should made by the affected EGU by November 1, 2020, to allow generators more time to consider if they can pursue the alternative path. As APPA comments have often shown, it can take several years for public power utilities to receive board and city approval to take a specified course of action in regards to a power plant. EPA and states should endeavor to create an alternative compliance pathway to ensure communities have a viable glide path for continued growth and prosperity.

VII. Comments on Elements of EPA's Proposed Rate-Based Federal Plan and Model Trading Rules.

APPA supports several elements of the rate-based plan, but EPA has failed to adequately justify its proposed decisions with respect to a number of key elements for that component of the

Proposed Trading Plan Rule. APPA strongly supports the Agency's proposal to allow banking under the rate-based plan. EPA should not adopt any of the limits on banking on which it requests comment. APPA urges EPA to expand the flexibility provided by ERC banking by also allowing limited ERC borrowing. The Agency has already provided for de facto limited borrowing within the Proposed Trading Plan Rule through the adoption of multi-year compliance periods. Expanded borrowing would provide additional flexibility to affected EGUs. The Agency's concerns about expanded borrowing are unfounded.

APPA believes that EPA—not affected EGUs, as proposed—should be responsible for ensuring the ultimate validity of ERCs. APPA also believes the Agency should not arbitrarily limit the categories of RE projects that qualify for ERC generation. Specifically, out-of-state RE should be widely available, all forms of biomass should be available, EPA should add new qualifying RE by direct final rule, and energy efficiency (EE) projects should be eligible to generate ERCs. Finally, Evaluation, Measurement, and Verification ("EM&V") requirements must not be overly burdensome and should be based on the state's existing policies where possible. These comments are further explained below.

A. EPA Should Allow Unlimited Banking of ERCs.

APPA supports EPA's proposal to allow unlimited banking of ERCs within and between compliance periods with no expiration date.[134] Unlimited banking provides an incentive for affected EGUs to take early action to make significant investments and emission reductions in order to reap the ERC value of those investments over multiple compliance periods. It also increases flexibility for affected EGUs by spreading the cost of compliance over a longer course of the rule's implementation. The ability to carry ERCs forward from one compliance period to

[134] 80 Fed. Reg. at 65,010

the next will increase regulatory certainty for affected EGUs because those EGUs will be able to plan for compliance based on their needs rather than on arbitrary periods established by the Agency.

EPA requests comment on whether it should place a quantitative limit on the number of ERCs that can be banked, whether the Agency should place a limit on inter-period banking, and whether ERCs should expire.[135] Each of these options would place unreasonable constraints on affected EGUs, which would be subjected to arbitrary dates or quantitative limits established by the Agency. These options would require an affected EGU to use or sell an ERC by a certain date (or before a certain limit is reached) or lose the value of the ERC. Once an affected EGU has generated an ERC, EPA has proposed no reasonable basis for stripping the affected EGU of the ERC if it does not use it or sell it. Rather than giving the affected EGU flexibility to use the ERC for compliance, sell it at a later date when prices have improved, or save it for a later compliance period when the affected EGU will need it, the limitations on which EPA requests comment could force an affected EGU to sell an ERC at an undesirable price or time (e.g., when the EGU would need it for compliance during the next compliance period). It could also result in affected EGUs losing the value of the compliance instrument altogether. These are all unreasonable results, and EPA should not adopt any of the options on which it requested comment.

B. EPA Should Allow Borrowing of ERCs.

The Agency should allow affected EGUs to borrow ERCs from future compliance periods, up to the end of the interim compliance period and every eight years thereafter, to meet current compliance obligations. Borrowing would provide significant flexibility to affected

[135] *Id*. at 65,010.

EGUs for use toward meeting their compliance obligations under the Proposed Trading Plan Rule. Affected EGUs would be able to spread the cost of compliance over multiple compliance periods and thus follow the lowest cost path to compliance, while still achieving the goals set forth in the Proposed Trading Plan Rule. Affected EGUs would have an increased ability to time generation shifts based on real-world circumstances, which would, in turn, improve reliability. Affected EGUs would also be able to make front-end investments in research and development that may pay off in future compliance periods, rather than being forced to divert those investments toward less efficient measures to comply with the Section 111(d) Rule's requirements.

The Agency discussed two concerns related to borrowing, but APPA believes that both of those concerns are unfounded. First, EPA requested comment on "a methodology that would allow ERC borrowing while maintaining the integrity of the compliance obligations."[136] The Agency can allow borrowing while maintaining the integrity of the Section 111(d) Rule's compliance obligations without any special methodology. EPA has already provided for de facto limited borrowing in its Proposed Rule through the use of multi-year compliance periods, which allows EGUs to effectively use future-year emission reductions over a short period of time to cover emissions that occurred earlier in the compliance period.[137] The Agency has also implicitly recognized that it was possible to meet BSER without strict adherence to the arbitrary dates established for the compliance periods.[138] ;Similarly, EPA should provide for expanded borrowing for the eight-year period of the interim compliance period and every eight years

[136] 80 Fed. Reg. at 65,010.
[137] *Id*. at 64,828-29 (allowing the emission goal to be met on an eight-year average or cumulative basis). *See also id.* at 64,868 (stating that it is possible for states to remedy shortfalls from a prior compliance period such that the revised plan would reflect BSER over the cumulative compliance period).
[138] *Id*. at 64,826

thereafter. An eight-year period will provide flexibility while ensuring that compliance is not pushed too far into the future.

Second, EPA stated that it had "reservations concerning [ERC borrowing] due to the fact that future ERC generation is not guaranteed."[139] These reservations are inconsistent with the foundations underlying EPA's Section 111(d) Rule. As noted above, the Section 111(d) Rule itself provides for de facto borrowing within up to three year periods through the adoption of a delayed compliance true-up. Furthermore, the glide path EPA has established through the increasingly stringent requirements that come into effect throughout the interim compliance period,[140] and the flexibilities provided to the states to deviate from that glide path,[141] allow EGUs to push compliance obligations further into the future. Here, the Agency has provided no reasoned basis to distinguish borrowing during the interim compliance period as a whole from de facto borrowing within the two- and three-year steps within the interim compliance period. Nor has EPA differentiated the flexibility provided by allowing deviations from the general glide path from the flexibility that limited borrowing would provide. Therefore, EPA's decision to prohibit borrowing is arbitrary and capricious and inconsistent with the Section 111(d) Rule.

C. EGUs Should Not Be Responsible for Ensuring the Ultimate Validity of Emission Rate Credits.

In the Proposed Trading Plan, EPA arbitrarily declares that affected EGUS are responsible for the validity of ERCs.[142] EPA—not the affected EGU—is positioned to ensure that a purchased ERC is a valid ERC. Indeed, as the issuer of ERCs, the Agency is charged with evaluating the adequacy of an ERC-issuance application and determining whether it is reliable.

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[139] *Id.*
[140] 80 Fed. Reg. at 64,666
[141] *Id.* at 64,786 n. 622
[142] 80 Fed. Reg. at 64,991.

An affected EGU, on the other hand, generally will have no ability or opportunity to assess or monitor the validity of an ERC (including whether paperwork errors occurred or whether the issuer perpetrated a fraud[143]). It is arbitrary and capricious for EPA to place a burden on regulated entities when they have no meaningful opportunity to address that burden. This is especially true where the Agency itself is in the best position to carry out such an obligation.

D. EPA Should Not Arbitrarily Limit the Categories of RE Projects That Qualify for Generation of ERCs.

EPA should not unreasonably limit the categories of RE that qualify for ERC generation. As explained below, out-of-state RE should be widely available for generating ERCs based on a simple demonstration. Additionally, all forms of biomass should be available for the generation of ERCs. Further, EPA should create an avenue to add new forms of qualifying RE. Finally, in order to avoid creating a disincentive for RE generation, EM&V requirements should be as least burdensome as possible.

1. EPA Should Make Out-of-State RE Widely Available for Compliance.

EPA proposes that out-of-state RE measures from a mass-based state will be available for use by a state under a rate-based federal plan if "it can be demonstrated that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state."[144] APPA agrees that RE measures from a mass-based state should be available for use by a state under a rate-based federal plan. In order to take advantage of this flexibility, EPA should require that a power purchase agreement exists between the EGU in the rate-based state and the RE provider and a simple certification by the RE provider that the RE measure will not receive mass-based set-aside allowances for any

[143] *See id*. at 64,991
[144] 80 Fed. Reg. at 64,978

generation. This same arrangement should apply in the case where an LSE has a clear ownership interest in an RE project. These requirements are simple and relatively less burdensome than EPA's proposed demonstration.[145] The Agency should also include catch-all provisions allowing other means deemed satisfactory to also support use of out-of-state RE. ERCs purchased pursuant to an approved demonstration should then be treated as any other ERC and be freely fungible.

2. All Forms of Biomass Should Be Eligible to Generate ERCs

EPA requests comment on the inclusion of biomass as an eligible measure in the rate-based plan.[146] If biomass is included as eligible, the Agency requests comment on an option to specify a list of pre-approved qualified biomass fuels.[147] EPA should include all biomass as eligible, pre-approved, and qualified under the rate-based plan. Biomass-derived fuels can yield climate benefits compared to conventional fossil fuels.[148] Plant growth associated with producing biomass-derived fuels can sequester carbon from the atmosphere and it is readily renewable.[149]

Additionally, evidence supports the conclusion that combustion of biomass contributes no net increase in atmospheric CO_2 concentrations. As multiple scientists have expressed to congressional representatives, "equating biogenic carbon emissions with fossil fuel emissions…is not consistent with good science and, if not corrected, could stop the development of new emission reducing biomass energy facilities."[150] This is because CO_2 released from

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[145] *Id*.
[146] *Id*. at 64,995.
[147] *Id*
[148] 79 Fed. Reg. at 34,924
[149] *Id*.
[150] Letter of Multiple Scientists to Senate Members of the Environment and Public Works Committee, Energy and Natural Resources Committee, and Agriculture Committee (July 20, 2010) submitted as an attachment to the EPA 111(d) docket by the National Alliance of Forest Owners. *See* EPA-HQ-OAR-2013-0602-35964.

biomass upon combustion would be released regardless of whether the biomass is converted to energy, and biomass that is burned for energy is quickly replaced by new growth. Additionally, the use of landfill gas, primarily methane (CH_4), as a generation fuel source aids in reducing GHG emissions. Methane has a global warming potential of 28-36 years compared to one year for CO_2.[151]

Scientists have also explained that net CO_2 emission from biomass combustion should be evaluated on a national scale. In a 2010 statement to Congress, multiple scientists stated that there were "750 million acres of forest land in the United States and this number is largely stable even as some forest land has been converted for development" while "forest growth nationally has *exceeded harvest* resulting in the average standing volume of wood per acre nation-wide increasing about 50 percent since 1952."[152] Because biomass is being replaced at the same pace as or more rapidly than it is being consumed, net CO_2 emissions are almost certainly neutral. As nationally applicable rules, the Section 111(d) Rule and the Proposed Trading Plan Rule are well-suited to take this fact into account.

Finally, biomass is abundant, convenient, and can provide reliable electricity unlike other forms of RE. EPA's regulatory policies should reflect these features along with biomass's carbon neutrality. Approving and qualifying all forms of biomass as eligible to generate ERCs under EPA's proposed rate-based plan would recognize the many benefits of biomass and provide additional flexibility to affected EGUs as they seek to meet EPA's stringent compliance requirements.

The decision to implement biomass-fueled electricity generation is unique in circumstance and scope. Some utilities will implement biomass generation because they have

[151] Methane combustion equation = CH4[g] + 2 O2[g] -> CO2[g] + 2 H2O[g] + energy
[152] *Id.* (emphasis added).

received clear community mandates to do so, while others will evaluate the option because it appears to be a cost-effective, readily available industrial or agricultural byproduct. In any case, utilities and their customers will want to fully understand all of the ramifications and many distinctive factors when considering investing in biomass as a fuel source. EPA should provide communities with the option to weigh those factors without undue process that might constrain reasonable and effective use of biomass as a compliance fuel.

Biomass-derived fuels also play an important role in controlling increases of CO_2 levels in the atmosphere. The use of some kinds of biomass has the potential to offer a wide range of environmental benefits. These benefits are realized regardless of how biomass feedstocks are sourced. For example, biomass can be used to actively offset fossil fuel use at the times when the least efficient marginal units are dispatched. In addition, biomass can be used to actively lower CO_2 emissions when solar and wind resources are not available. In both cases, the CO_2 reductions are much greater than identified because the biomass is being optimally used to reduce emissions. APPA agrees with EPA's Science Advisory Board (SAB) report that "biogenic feedstocks that displace fossil fuels do not have to be carbon neutral to be better than fossil fuels in terms of their climate impact.''[153] APPA would add that despite the results of relative lifecycle assessment methodologies (whose data are highly influenced by scope), biomass has high potential to reduce CO_2 emissions in an active fashion unlike many other renewable resources.

Emissions of CO_2 from net-zero or below-zero biomass fuels should be exempt from compliance under the Proposed Rule if those CO_2 emissions meet a state-defined exemption standard for biomass. The California Air Resource Board (CARB) exempts any biomass fuel "if

[153] http://www.epa.gov/sab.

an operator or supplier is able to successfully verify biogenic emissions from biomass fuels that meet the exemption requirements; they are not required to surrender compliance instruments for the verified exempt biogenic emissions."[154] Providing an exemption of any certifiably net or below zero CO_2 biomass fuels is similar to the CARB biomass exemption. If an EGU or biomass supplier is able to successfully verify biogenic emissions from biomass fuels that meet state exemption requirements, then the EGU or biomass supplier should not be required to surrender compliance instruments for the verified exempt biogenic emissions. The CO_2 emissions associated with the combustion of "qualify exempt biomass fuels" should be reported as exempt for emission reporting purposes. Verifiers should only be required to confirm that the EGU or supplier can document and demonstrate that CO_2 emissions from biomass fuels meet the all applicable state requirements. Biomass generation of any kind should qualify for generation of ERC's under 40 C.F.R.§ 62.16435.

a. APPA Supports the Development of a Pre-Approved List of Qualified Biomass Feedstocks to Reduce Compliance Uncertainty.

APPA appreciates EPA asking for public comment on the development of a pre-approved qualify list of biomass feedstock. Waste-derived feedstock plays an important role in developing CO_2 emission reduction strategies. EPA should recognize biomass feedstocks from sustainably managed forest lands on the pre-approved list of qualified biomass feedstock. In addition, the Agency should rely on state-established requirements that demonstrate the feedstock is sourced appropriately. Many states have already recognized the importance of waste-derived feedstocks via mandatory and voluntary programs.

[154] http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/biomass.pdf

Compliance uncertainty will be reduced with the establishment of a pre-approved list of qualified biomass feedstocks published by EPA. The pre-approved list could be amended in the future as the science related to biogenic CO_2 emissions assessments evolves, but should not place any burden on entities already in possession of biogenic fuel certified under an earlier version of an EPA pre-approved list.

EPA should consider measures to reduce uncertainty, as well as incorporate existing state standards and measures, in its approval process. State renewable energy standards, federal renewable fuel mandates, and public or regulatory pressure to reduce CO_2 intensity have increased organizational interest in using biomass for power generation. Utilities thinking about using biomass have to consider potential permitting hurdles, uncertain feedstock prices and availability, and uncertain technology or facility modifications necessary to burn biomass to generate electricity. Whenever the Agency adds to uncertainty about whether a given fuel will meet an EPA test for carbon neutrality, it is effectively damping the market for biomass-related fuels. At a minimum, EPA should declare all biomass has some degree of CO_2 neutrality and leave it up to each state to determine the level of that neutrality, even under a federal plan. EPA may be unfairly over-scrutinizing biomass projects and should provide biomass opportunities instead.

Like fossil or nuclear power—and unlike more intermittent solar or wind generation resources—biomass can provide a form of baseload power. A baseload plant can run virtually all the time, thus it is an important tool for meeting a utility's obligation to provide reliable energy service. In addition, resiliency is the capability to manage effectively in the aftermath of prospective events—such as extreme weather, a terrorist event, shortages, price hikes, or disruptions in other states or even nations—that could leave a community vulnerable to

disruption in the flow of energy. Biomass use and a well-established biomass supply chain can improve a generator's ability to mitigate supply interruption events by increasing fuel flexibility while meeting environmental objectives. The pre-approval of biomass as a compliance option will add certainty to the biomass marketplace.

In the final federal plan, EPA should approve biomass generation from all types of biofuels if they are approved by the state. The Agency should also approve biomass as an ERC-generating compliance mechanism for all entities of all sizes, if the state decides to allow it. For example, if smaller combustion engines want to use biomass-derived fuels, they should be allowed to use those fuels and propose their use for compliance credits to be sold to other generators.

EPA should also include waste-based biofeedstocks and residues of non-energy crops as qualified biomass. These fuels have been called "opportunity fuels" because their use creates an opportunity to more sustainably use a material that would otherwise be considered pollution or waste.

b. The EPA Should Allow States, Biomass Developers and EGUs to Demonstrate That Feedstocks Meet the Requirements to Be Accepted as Preapproved Qualified Biomass Feedstocks.

Again, APPA appreciates that EPA has raised this issue. The Agency should allow sources to seek approval for other types of biomass to be added to the pre-approved list. This process could include several steps, but should be relatively simple and easy to complete. Different types of biomass call for different collecting, processing, transporting, and storing regimes, so the process should be as broadly applicable as possible.

The EPA process should consider how to enhance production of forest- and agriculture-derived biomass fuels and their related CO_2 benefits. As mentioned in these comments, the process should be as simple as reasonably possible. EPA only needs information on any additional fossil fuel inputs used to grow the biomass to its point of harvest or a determination from the state that the biomass would otherwise be classified as waste.

The Agency should recognize that there are types of biomass that if left on the forest floor, would turn into far more potent greenhouse gasses. In these cases, EPA should find a means to award the below net-zero emissions value of biomass fuels to their consumers. For example, below-zero emissions scenarios can occur when fine, narrow-diameter woody materials are burnt in a power station instead of being left on the forest floor, where they would rapidly decompose and release methane. Reducing forest floor off-gassing and encouraging high carbon density afforestation to provide additional biomass fuels (replacing low carbon density crops with biomass crops) has potential to positively impact global CO_2 balances and should be encouraged by the EPA.[155] If states are creating afforestation for biomass and replacing low carbon density crops, they should be able to generate ERCs below the net-zero nature of the biomass fuel creation.

One possible process to demonstrate feedstock qualifications could involve a preliminary application including a preliminary feasibility assessment that considers the production, processing, and use of not-yet approved biomass fuels, as well as related CO_2 benefits. This preliminary application could be completed by a state, EGU, or biomass developer. This process would only require accounting for fossil fuel inputs that are significant and material to the direct

[155] https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=9&ved=0ahUKEwihjdLqvc_JAhVBJCYKHQSLAsYQFghKMAg&url=http%3A%2F%2Fwww.eforester.org%2Ffp%2Fal_lucier.ppt&usg=AFQjCNFpOPeAEGXa30ympYyGjL-9A7vPPw&cad=rja

production of the biomass feedstock. This process should also consider estimated CO_2 offsets and reductions that come from the production of the proposed feedstock.

This preliminary feasibility assessment could also provide a rate-based estimate of the relative ERC (similar to the Federal Plan gas shift methodology) that would be produced by generating one MWh from the specified biomass fuel. This preliminary assessment only needs to include the factors that would be required for EPA to determine the nature of the carbon offset derived from the biomass fuel. This information collecting activity should be limited in scope or it will unfairly include fossil fuel emissions that are associated with all energy sources, but that are not examined as a part of this rulemaking (for example, storage and transportation fuel consumed). Once EPA has approved the preliminary application, the state subject to a federal plan, in consultation with affected entities, should have the option to determine a set amount of ERC credits per MWh that can be derived from an EGU through use of this fuel.

c. EPA Should Pre-Approve and Qualify Biomass Resources in a Blanket Fashion Providing Only the Detail Necessary to Allow States to Make Their Own Informed Decisions on the Relative CO_2 Neutrality of Various Feedstocks.

By limiting biomass use, EPA would unnecessarily and unduly create a limitation on available means to comply with a federal plan imposed on a state. For example, certain states in the southeast will likely rely more on biomass for compliance because they do not have the solar, wind, or hydropower resources comparable to other states. EPA's national assumptions on solar, wind, and hydropower development will fall short in these states and therefore biomass is needed as an option.

The Agency should also pre-approve and qualify as many biomass sources and fuel types as possible to reduce compliance uncertainty, including, but not limited to, the following biomass sources (listed in alphabetical order):

- Agricultural byproducts – Crop residue from a nearby agricultural or silvicultural crop. After these crops are harvested, residues are often left in the field or open burned. Some of these residues must remain in the field to keep the soil healthy. Crop residue that is not needed for soil productivity, however, can be an opportunity fuel for power production. In addition, EPA should consider that crop residues emit CO_2 and other greenhouse gasses when they are left to rot in the field or open burned. Producing power with these residues avoids such emissions.[156]
- Energy crops – An energy crop is cultivated and harvested primarily for biomass feedstock. It could be an agricultural (herbaceous) or silvicultural (woody) crop. Energy crops include grasses or trees that can be grown on land poorly suited for food crops. A permitting process (for example) has been established by Florida law to avoid cultivation of non-native invasive energy crops.[157] EPA encourages and supports energy crops on mined sites, such as Florida's reclaimed phosphate lands in central Florida,[158] or contaminated sites.[159] A community may seek to promote energy crops as a means to encourage rural preservation. This is a perfect example of biomass that EPA should pre-approve for compliance.

[156] See Cedar Falls Utilities in Appendix 1
[157] Permit Requirements for Planting Non-native Energy/Biomass Crops in Florida**,** Langeland, http://edis.ifas.ufl.edu/ag339
[158] http://edis.ifas.ufl.edu/eh213 (12/10/11)
[159] http://www.epa.gov/oswercpa/rd_faq.htm#initiative (accessed 12/9/13)

- Biogas that is being flared, such as from a wastewater treatment facility that uses anaerobic digestion to manage its sludge, a landfill that has a biogas collection system in place, or an animal farm that uses anaerobic digestion to manage manure. (These types of facilities sometimes produce or capture biogas for regulatory or process-efficiency reasons, but in many cases, do not then use the biogas to produce power).[160]
- Wood products manufacturing residue/waste – This could be sawdust or other biogenic wastes from the manufacturing process or residue from the harvest of timber for wood products manufacturing (the tops of harvested trees are typically not used in the manufacturing process and so are left in the field, either to rot or to be open burned). The equipment used to harvest the timber can also be employed to collect the residue.[161]
- Animal Manure – Animal waste is manure and bedding, such as from cows, horses, swine, and chickens at a farm or feedlot. Animal manure is used to produce electricity, thermal energy for onsite use, and various byproducts (such as fertilizer or animal bedding). Cases studies show examples of both central and distributed power from animal waste feedstock and the conversion of animal waste to biogas or syngas. Farm animals are a major source of greenhouse gas emissions. For example, as a rough estimate for manure from a dairy farm, one can estimate 150 to 200 watts per cow from anaerobic digestion. There is a lot of methane being emitted from these sources that is ready to be recovered by the power sector.[162]
- Food processing residue – Food processing residue is waste from food processing industries, such as from fruit and vegetable processing, making dairy products, meat and

[160] City of Portland Green Purchasing Case Study, On-Site Renewable Energy: Biogas, http://www.portlandoregon.gov/brfs/article/157988 (December 2013)
[161] See Burlington Vermont in Appendix 1
[162] Lowell Light and Power in Appendix 1

seafood processing, sugar industry wastes (cane and beets), ethanol industry waste, restaurants, grocery warehouses, and fats, oils and grease (FOG). Disposal of FOG in domestic sewers is prohibited (FOG hampers operation of sewage treatment facilities), so a FOG waste generator must pay to dispose of it. FOG can be a source of both revenue and feedstock to a power producer.[163]

- Urban wood waste – Urban wood waste includes the woody debris generated by tree-removal businesses and organic materials that homes and businesses dispose of, such as trimmings from yard maintenance, land development, right of way clearing, wood pallets, furniture, scrap lumber, etc. These businesses pay a tipping fee to dispose of this debris at the local yard waste landfill. There may be an opportunity for a power developer to receive these materials at little to no expense and also expand the life of the landfill.[164]
- Forest/Park Management Residues – The management plans that direct the operation of publicly owned forests and parks often create organic residues. The residues may be from routine maintenance (e.g., grass cuttings, maintaining roads/trails, etc.); ecosystem restoration initiatives, such as to eliminate non-native plant species, particularly invasive species; or fire safety operations (to prevent fires or to reduce fire risks associated with burns prescribed for ecosystem restoration). Such residues are typically open burned or left to rot, causing climate and particulate pollution. Selling or donating the residues could avoid this pollution. It could, depending on the residue type and local markets, produce profit to supplement other revenue sources. One study found that the profits from the sale of hardwoods that must be removed to restore long leaf pine savannas

[163] Id.
[164] USDA, Successful Approaches to Recycling Urban Wood Waste http://www.fpl.fs.fed.us/documnts/fplgtr/fplgtr133.pdf (October 2002)

ecosystems could finance restoration of those ecosystems: "adoption of this cost-effective solution would reduce the risk and severity of wildfires while enhancing biodiversity protection and reducing emissions of greenhouse gases. By selling the invasive hardwoods to the highest bidders, the costs of pine savanna restoration are greatly reduced or even made profitable."[165]

- Wastewater Treatment Facilities (WWTF) – Wastewater treatment facilities (WWTFs) that use anaerobic digesters to treat their waste are an excellent technical fit for combined heat and power (CHP) and should be automatically qualified for any proposed project as a CO_2 reducing form of generation that should be allowed to generate ERCs. The report, Opportunities and Benefits of Combined Heat and Power at Wastewater Treatment Facilities, provides engineering rules of thumb for estimating the generation potential at a WWTF and links to case studies demonstrating the benefits of CHP at WWTFs.[166]
- Other wastes whose disposal or management is costly or poses risks to public health. These could include animal waste or hurricane debris. At least one city is considering use of biosolids from wastewater treatment.[167]

Demand for biomass residues from the logging industry (wood pellets) is on the rise from European power providers looking for long-term, sustainable feedstock for their energy facilities. It would be a shame if due to EPA regulations; the biomass market in the U.S. was simply

[165] Countering the Broadleaf Invasion: Financial and Carbon Consequences of Removing Hardwoods during Longleaf Pine Savanna Restoration Condon, Putz, 2007. Restoration Ecology. 15 (2): 296-303, http://onlinelibrary.wiley.com/doi/10.1111/j.1526-100X.2007.00212.x/abstract; http://news.ufl.edu/2007/05/29/hardwood-fuel-win-win-oped/; http://news.ufl.edu/2007/05/22/longleaf-fires/
[166] www.epa.gov/chp/markets/wastewater.html
[167] See Ocala, Florida in Appendix 1

exported to achieve CO_2 reductions in Europe rather than being used to facilitate domestic CO_2 reductions.[168]

Many states have recognized the importance of forests and other lands for climate resilience and mitigation and have developed a variety of different sustainable forestry policies, renewable energy incentives and standards, and greenhouse gas accounting procedures. Because of the positive attributes of certain biomass-derived fuels, EPA also recognizes that biomass-derived fuels can play an important role in CO_2 emission reduction strategies. The Agency should allow states to consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans to meet the emission reduction requirements of this rule. APPA believes it is important to define a clear path for states to do so.

d. Other Requirements That Should Be Included in the Final Model Rule Regarding EM&V for Qualified Biomass.

In response to EPA's request for comments on other necessary requirements, and as mentioned earlier, CO_2 emissions resulting from the combustion of net-zero or below-zero biomass fuels should be exempt from a compliance obligation under an EPA imposed federal plan if they meet state defined standards. If an EGU or biomass supplier is able to successfully verify biogenic emissions from biomass fuels that meet state exemption requirements, they should not be required to surrender compliance instruments for the verified exempt biogenic emissions. The emissions associated with the fuels should be allowed to simply be reported as exempt biomass fuels. Verifiers should only be required to confirm that the EGU or supplier can

[168] http://www.theenergycollective.com/todayinenergy/2220181/uks-renewable-energy-targets-drive-increases-us-wood-pellet-exports

document and demonstrate that the biomass fuels reported as exempt meet the all applicable state requirements.

EPA should allow states to determine that emissions from biomass fuels that are not mixed with fossil fuels prior to combustion or oxidation, or which are measured separately from fossil fuels, be calculated using any available calculation or "tier" under subpart C of the EPA Mandatory GHG Reporting Rule 40 CFR Part 98.33(a).

3. EPA Should Adopt a Process for Adding New Qualifying RE.

EPA should add new technologies to the set of eligible measures under the Proposed RUle using the same approach it took in the final Section 111(d) Rule: identify adequately demonstrated technologies while fostering innovation and supporting new types of generation. The Agency, on its own or based on a petition from stakeholders, should review new technologies within a reasonable timeframe. If a measure is adequately demonstrated, EPA should adopt the measure in a direct final rule. As is consistent with the Agency's general practice for direct final rules, if adverse comments are received, EPA should withdraw the direct final rule and address public comments with a final rule within one month without initiating a further comment period.

4. Energy Efficiency Projects Should Also Be Eligible for Generating ERCs.

EPA requests comment on issuing ERCs for EE measures under a federal plan.[169] The Agency should allow all EE measures to generate ERCs and be used for compliance with the Section 111(d) Rule. Although APPA agrees with EPA's determination that use of EE measures as a building block to define BSER would be unlawful, EPA should allow their use as a compliance mechanism under the Proposed Trading Plan Rule.

[169] 80 Fed. Reg. at 64,994

EPA also requests comment on how EM&V measures could be implemented across multiple jurisdictions for EE measures in the timeframe provided by the rule.[170] States have extensive experience producing rigorous and demonstrably effective EM&V measures. As the Agency explained in the proposed Section 111(d) Rule, "states have conducted ongoing EM&V of demand-side EE [] programs for several decades."[171] EPA has already reviewed these EM&V requirements extensively, and should allow states and affected EGUs to use existing state EM&V requirements and measures where possible. Indeed, the Agency could easily incorporate a state's EM&V requirements into a federal plan for that state. If a state had no EM&V requirements for a particular EE measure, EPA could adopt a host of options from other states and allow affected EGUs to select the most appropriate measure. A similar approach would be appropriate for use in EPA's model trading rules and would allow for timely adoption of these sorts of measures well before implementation of the rule takes place.

a. Municipal Utilities Have Experience Implementing Energy Efficiency Measures.

Public power utilities across the nation have undertaken, and continue to implement, a diverse portfolio of approaches to EE measures. Due to the multifarious nature of EE projects from public power utilities, it is important for EPA to remain flexible when determining requirements for such projects as they relate to ERC generation. APPA encourages EPA to review projects in APPA's Energy Efficiency Resource Central and the case studies submitted in response to the Section 111(d) Rule by the National Association of State Energy Officials (NASEO) when considering utility EE programs that should be readily accepted for ERC

[170] *Id*. at 64,995.
[171] 79 Fed. Reg. 34,830 and 34,920.

generation.[172] APPA's research and development program, the Demonstration of Energy and Efficiency Developments program, has helped fund numerous projects related to energy efficiency for municipal utilities.[173] It has helped develop and accelerate deployment of the most practical and cost-effective efficiency technology with APPA's members for almost 35 years.

APPA also agrees with the suggestion made by NASEO that EPA recognize that states or private entities may voluntarily contribute to, or develop a "registry," to establish a publicly available repository of EE programs. A registry should provide clear attribution and ownership of energy savings and be used by the state to perform audits and assure credibility of savings and emissions reduction claims, credits, and/or allowances.

E. EM&V Requirements Must Not Be Burdensome.

In the Section 111(d) Rule and Proposed Rule, EPA includes the use of demand-side energy efficiency as a method for compliance. However, for many entities, this compliance option may be effectively eliminated due to unnecessary and overly burdensome EM&V requirements included in the Proposed Rule.

EPA should recognize that states have considerable experience addressing EM&V issues. The Agency has previously noted that states and utilities have led the way in developing EM&V standards.[174] EPA is right that states have the appropriate experience and it should recognize this in the final federal plan and model rules.

The federal plan and model rules should adopt existing state EM&V standards and include provisions for incorporating additional, and updating existing, EM&V options as states

[172] http://www.publicpower.org/Topics/Landing.cfm?ItemNumber=38508&navItemNumber=37540
[173] http://www.publicpower.org/Programs/Landing.cfm?ItemNumber=31245&navItemNumber=37529
[174] 79 Fed. Reg. at 34,902

develop them, providing a broad array of EM&V options. Affected EGUs covered by a federal plan should have the option of choosing among the various state EM&V protocols that are incorporated into the federal plan, as best suited to their circumstances. In addition, EPA should not attempt to impose additional, unnecessary EM&V requirements on the states. Nor should the Agency burden and thereby discourage the use of EE measures by imposing onerous monitoring and verification requirements.

1. EPA Should Adopt State EM&V Requirements for Purposes of Any Federal Plans and the Model Trading Rules.

As stated above, EPA should allow states to choose the EM&V requirements that the states deem appropriate. Development of appropriate requirements is a traditional state role and state practices are well-established in this area.[175] ("Utilities and states have conducted ongoing EM&V of demand-side EE and RE measures and programs for several decades. Current practice with EM&V for RE and demand-side EE programs in the U.S. is primarily defined by state public utility commission requirements.").[176] States have robust existing EM&V programs—many of which EPA is already familiar with—that may be appropriate for implementing the requirements of the Proposed Trading Plan Rule. To the extent possible, EPA should defer to a state's choice of EM&V requirements. If it is not possible to use the state's choice or its existing requirements, the Agency should adopt a host of EM&V options from among the established state policies and allow affected EGUs to select the option that best suits their individual needs. Providing well-established EM&V practices based on existing state requirements and providing options to EGUs will provide the strongest incentives to use EE and RE measures.

[175] See, e.g., 79 Fed. Reg. 34830, 34920
[176] *Id*.

APPA recommended its comments in response to EPA's proposed Section 111(d) Rule that the Agency allow flexibility in measurement and verification (M&V) protocols.[177] In the proposed Section 111(d) Rule, EPA noted that the EM&V requirements provided would leverage existing industry practices currently utilized by the majority of states implementing renewable generation and demand-side energy efficiency. APPA is in agreement with EPA's intention of relying on existing state practices. Nevertheless, APPA also encourages the Agency to provide guidance, not requirements, on indicative approved methodologies to measure and verify energy savings from EE measures (both single technology and whole building measures). This guidance should include a process for states and industry to submit additional methodologies for consideration and approval. To reiterate some of the points made in APPA's previous set of comments, APPA recommends that EPA begin developing a resource for states of EE projects by pulling from existing approved state practices. These should include, but not be limited to:

- Uniform Methods Projects standard;
- International Performance Measurement and Verification Protocol;
- ASHRAE Guideline 14-2002 Measurement of Energy and Demand Savings;
- DOE's Superior Energy Performance program created an M&V protocol for industry;
- Technical Reference Manuals or TRMs ("deemed savings" charts that provide statistical savings value for equipment upgrades);
- SEE Action Network and regional standards such as those by NEEP and the Northwest's Regional Technical Forum;
- ISO 50001:2011 Energy management systems; and

[177] Comment submitted by James J. Nipper, Senior Vice President, Regulatory Affairs and Communications, American Public Power Association, EPA-HQ-OAR-2013-0602-22871, 79 Fed. Reg. 34,830 (June 18, 2014) http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-22871

- Demand response measurement and verification, such as the National Action Plan for DR M&V element.[178]

Existing state and utility programs should be recognized by the federal plan as they represent cost effective EE opportunities. These programs may include, but not be limited to:

- Utility Demand Side Management programs;
- EERS requirements. EERS carve out for ratepayer-funded rebates/incentives;
- Other highly efficient EE appliances and equipment upgrades not included in EERS or in states with no EERS; and
- Innovative energy savings programs that have measureable reductions, such as tree planting.

In the Proposed Rule, EPA references the input received by industry during the Section 111(d) Rule public comment period regarding current practices in EM&V. Based on the feedback received, the Agency acknowledges the use of TRMs and "deemed" savings as proposed methods for EM&V for certain types of programs.[179] APPA is in full support of EPA's decision to propose these methods in the proposed rule and encourages the Agency to include them in the final rule as valid methods of EM&V under a state or federal plan. Further, APPA encourages EPA to include the above-listed methods in the final rule EM&V guidance.

2. EPA Should Provide Smaller Entities Guidance to Implement EM&V Protocols for Their Efficiency Programs.

EPA should consider changing the proposed required eligibility criterion, described in Section IV.C.3 in the preamble of the Proposed Rule, to include additional flexibility for smaller

[178] http://emp.lbl.gov/sites/all/files/napdr-measurement-andverification.pdf
[179] 80 Fed. Reg. 65,006

entities. EM&V requirements could easily become burdensome and costly for small entities because they do not have the resources (e.g., workforce, funding, etc.) and also have a smaller customer base over which to share costs in order to accomplish the same amount of reporting and analysis as larger utilities.

APPA recommends EPA establish a subcategory group of utilities that will have more streamlined requirements for their EM&V reporting. The development of these protocols and methods for measuring and verifying energy savings will take time and the Agency should take caution and avoid any imposition of EM&V requirements on the states, which may discourage the use of EE as a method to generate ERCs.

As mentioned previously, APPA applauds EPA for referencing input from the public comment period regarding existing EM&V practices for utility EE programs. Further, APPA encourages the Agency to finalize these methods, such as using TRMs and "deemed" savings, in the final rule for a state or federal plan. These methods are commonly used in public power programs and are of particular importance for smaller scale projects and for small public power utilities.

For example, MRES, joint action agency of public power utilities in the Mid-west region, created a comprehensive in-house database to log information on savings measurements, measure lives, etc., for all types of EE programs for their smaller utilities to use for EM&V. In addition, for relevant programs, MRES' database itemizes the savings for each load shape to ensure a more accurate savings measurement. EPA should finalize cross-state EE measurement and deemed savings resources in the final federal plan rule.

Practices, such as utilizing a TRM, have been tested meticulously by the industry and have proved to be more than sufficient in providing a low cost and reliable option for smaller

entities. APPA is in agreement with EPA's proposal to include methods such as TRMs in the final rule for a state or federal plan to help maintain flexibility and simplicity, especially for small utilities. To illustrate the value of simplified EE measurement and verification methodologies, APPA provides the following examples:

a. Lighting Retrofit Program.

In a typical lighting retrofit program, the energy savings for a specific project would depend on many factors, including existing lighting technology, new lighting technology, control strategies, and whether the illumination level is changed during the retrofit. The administering party would be responsible for justifying the standard to be used in the identified lighting retrofit program. Rather than going through a lengthy EM&V process, many entities would choose to qualify their programs through established efficiency rating programs, such as Energy Star, the Design Lights Consortium, Consortium for Energy Efficiency, etc., which are a less costly method of qualifying the program's efficacy.

Savings calculations used for EE programs of this type are approved by entities, such as the state energy office, relevant utility commission, local utility and/or their governing board, municipal authority, etc., and are based on credible studies that are published in TRMs. Project implementers will use state and regional specific TRMs or EE savings databases. If a state has a TRM of its own, the utility or entity administering the program will typically adhere to the state's TRM. However, if the state does not have one of its own, the entity administering the program should be allowed to utilize a TRM created in-house or one that is created by a different state, to quantify savings from the program.

b. Direct Install Program.

Another example of a small utility EE program is the direct installment of refrigerators in small businesses. Typically a small utility with this type of program will ensure savings calculations are done through a licensed engineer, pre-inspections and post-installation inspections are completed, sometimes meters are used, and third party verifiers to check that their methods meet the standards. Requiring more stringent EM&V, such as adding additional meters or making a lengthier verification process is extremely problematic because the customers would not be willing to pay more for saving energy, nor would the margin of error be much reduced from the TRM calculations. For smaller-scale programs implemented by small utilities, it is not ideal to increase the EM&V burden for programs that do not have a substantial amount of savings. These small programs have savings that benefit the mission to reduce CO_2 emissions, but unnecessary EM&V will discourage small utilities from using EE as a means of compliance.

EPA should increase flexibility in EM&V requirements for EE measures to encourage the implementation of such measures without being overly burdensome and costly for small utilities. Widely adopted and state-approved methods of EM&V should be acceptable.

3. Gross Savings Should Be Allowed to Be Used in EM&V.

In the proposed Section 111(d) EM&V guidance document, EPA proposed the use of net savings for the quantifying EE savings. However, APPA recommends the Agency explicitly state in the final federal plan rule the allowance of gross energy savings to measure and document EE savings under a state or federal plan. This will significantly help lessen the record-keeping burden on states and utilities, while being an accurate measure of savings.Net savings are more difficult to measure and to verify. In addition, there is such variety in the methods and

approaches used by states to determine net savings that there would be difficulty in assessing the appropriate method to do so. The trade-offs between the time and monetary resources that must be devoted to evaluation and the level of sophistication of net savings analysis that can be conducted needs to be considered.[180] APPA recommends EPA consider the use of gross savings, which is commonly used in the industry today, is accurate in determining EE program savings, and is simple to determine.

4. Transmission and Distribution Losses Should Be Calculated Based on an Annual Average.

In the Proposed Rule, EPA requests comment on the presumptively approvable approach to quantifying the electricity savings that result from avoiding a transmission and distribution (T&D) system loss. The Agency states that each EM&V plan must quantify the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity consumption measured at the end-use meter or statewide annual average transmission and distribution loss rate from the most recent year that is published in EIA's State Electricity Profile. However, this number is not accurate in describing the avoided T&D losses. EPA should provide guidance on common practices of determining the avoided losses, but should not require that the calculation be made based on an annual average. Because there are numerous methods for adding supply-side efficiency to a distribution system, APPA recommends EPA allow states and utilities to use their existing methods of calculating T&D losses for their EM&V submittals.

5. EM&V Requirements for Eligible Renewable and Nuclear Sources Should Be Based on Existing Practices.

To ease the burden of reporting requirements under the Proposed Trading Plan Rule, EPA should reconsider the threshold for aggregating renewable generation output. The proposed

[180] http://aceee.org/blog/2014/01/net-savings-non-evaluators-some-conce

threshold is set at a collective nameplate capacity of one MW and individual capacity of less than 150 Kilowatts. Instead, APPA recommends a collective nameplate capacity of 10 MW and individual capacity of less than one MW. This would help promote small-scale renewable projects (under than 10 MW), which make up approximately six percent of the renewable generation capacity (excluding hydropower generation) in the United States.[181]

In addition, APPA encourages EPA to allow facilities to aggregate the total generation of their units, regardless of whether they have the same essential generation characteristics, as long as they meet the minimum threshold and are uniquely identified in the federal tracking system. For instance, a utility should be able to aggregate the output from its solar garden, as well as a wind farm it owns when reporting to EPA to generate ERCs.

6. EPA Should Increase the Threshold to Determine Small-Scale Renewable Sources.

APPA is in agreement with EPA's decision to create a threshold to determine small-scale renewable generating facilities and allow the outputs from those sources to be estimated. However, APPA encourages the Agency to increase the maximum threshold from 10 Kilowatts to 10 MW when determining which facilities are able to make an estimate. In addition, APPA suggests that EPA reconsider its decision to only apply this exception to facilities located in states that explicitly allow estimates to be used. This exception should apply to all utilities within the threshold. However, if a state has an existing policy in place, EPA should acknowledge the state's practice in quantifying, verifying, and reporting RE generation.

The requirement set for estimating output of small-scale sources is not specified by EPA. Similar to EE measurement and verification, the Agency should acknowledge a statewide, regional, or national tool (e.g., software, spreadsheet calculator, technical manual, etc.) that helps

[181] U.S. Department of Energy, Energy Information Administration, Independent Statistics & Analysis

utilities determine an appropriate estimate of generation (or avoided generation) as a result of the renewable source. APPA agrees that the tool used to estimate generation should consider the RE unit's capacity and an appropriate assessment of local conditions that affect generation levels. Tools created by the state or joint action agency should be pre-approved by EPA to be used for this purpose.

7. EPA Should Rely on Existing State and Utility EM&V Practices for Combined Heat and Power Systems.

CHP units are uniquely suited to reduce emissions of affected EGUs and reduce demand for generation. As such, EPA should promote flexibility that would further encourage the implementation and development of CHP. Similar to the statements made in the previous sections of these comments, APPA encourages the Agency to rely heavily on existing state EM&V practices for CHP. By alleviating the cost burden of increased EM&V, EPA will encourage the development and implementation of CHP as a method to generate ERCs under a Section 111(d) state or federal plan.

In addition, EPA should acknowledge that any non-affected CHP units being used in a state plan for the purpose of generating ERCs should not have to report CO_2 emissions in their EM&V reports. Under this scenario of non-affected CHP units being used to generate ERCs, CO_2 emissions should not be required to be reported to EPA. The Agency should not expect these units to utilize continuous emission monitoring (CEMS) devices due to the significantly increased cost burden. EPA should instead permit these units to calculate mass emissions using less expensive methodologies, such as those based on fuel use.[182]

[182] Comments of CHP Association on Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602

VIII. Comments on Specific Elements of EPA's Proposed Mass-Based Federal Plan and Model Trading Rules.

Although APPA believes the Section 111(d) Rule and any plan to implement that rule, including the Proposed Trading Plan Rule, are unlawful, APPA supports several elements of the mass-based plan, assuming such a plan can lawfully be implemented. Other elements of EPA's proposed mass-based plan, however, are not adequately justified. As with the rate-based plan provisions, APPA strongly supports EPA's proposal to allow unlimited banking under the mass-based plan. Unlimited banking will increase flexibility and certainty for affected EGUs. APPA also urges EPA to expand the flexibility provided by allowance banking by also allowing borrowing. The Agency already has provided for de facto borrowing within the rule through the use of multi-year compliance periods. Expanded borrowing would provide additional flexibility to affected EGUs, and the Agency's concerns about expanded borrowing are unfounded.

Furthermore, biomass should be treated as "qualified," and no emissions attributed to biomass should require allowances. APPA believes EPA has not provided an adequate justification or explanation for the necessity of its leakage provisions. The Agency should include leakage provisions only if analysis demonstrates that leakage will occur and result in significant overall CO_2 emission increases. Even if the leakage provisions were permissible, EPA's proposed documentation requirements for "qualifying RE" are overly burdensome. In addition, EPA should allow states to take over allowance allocation while otherwise remaining subject to a federal plan and should not require a state to implement the CEIP program as a condition of taking over allowance allocation. Finally, EPA should credit units that shut down with allowance allocations throughout the remainder of the Section 111(d) program, not the limited period of time that EPA proposes.

A. EPA Should Allow Unlimited Banking.

APPA supports EPA's proposal to allow unlimited banking of allowances with no restriction on the use of banked allowances, including from the interim period into the final period.[183] Unlimited banking provides an incentive for affected EGUs to take early action to make significant investments toward emission reductions in order to reap the reduced need for allowances from those investments over multiple compliance periods. It also increases flexibility for affected EGUs by allowing them to spread the cost of compliance over a relatively longer period of the rule's implementation. The ability to carry allowances forward from one compliance period to the next will increase regulatory certainty for affected EGUs, because they will be able to plan for compliance based on their needs rather than on arbitrary periods established by the Agency. Unlimited banking between compliance periods only increases this flexibility, and EPA has not provided any reasoning in the Proposed Trading Plan Rule to limit this flexibility.[184]

B. EPA Should Allow Borrowing.

EPA should allow affected EGUs to borrow allowances from future compliance periods, up to the end of the interim compliance period and every eight years thereafter, to meet current compliance obligations. Borrowing would provide significant flexibility to assist affected EGUs in meeting their compliance obligations under the Proposed Trading Plan Rule. Affected EGUs would be able to spread the cost of compliance over multiple compliance periods, and thus follow the lowest cost path to compliance, while still achieving the goals set forth in the Proposed Trading Plan Rule. Affected EGUs would also have an increased ability to time generation shifts based on real-world circumstances, which would, in turn, improve reliability.

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[183] 80 Fed. Reg. at 65,014.
[184] *Id*.

Allowing borrowing is consistent with the Section 111(d) Rule and the foundation of EPA's Proposed Trading Plan Rule. The Agency has already provided for de facto limited borrowing in the Proposed Rule through multi-year compliance periods.[185][186] EPA also implicitly recognizes that it is possible to meet emission reductions equivalent to those that can be achieved through application of BSER without strict adherence to the arbitrary dates established for the compliance periods.[187] EPA's prohibition on borrowing is internally inconsistent with these provisions, and the Agency has not provided an adequate or reasonable basis to support such a prohibition.

EPA can also adequately address the purported complexities that might be caused by borrowing. The Agency requests comment on "how to address removing the extra allowances from circulation that would result if borrowed allowances originate in a state that subsequently withdraws from the mass-based trading program and on other complexities that borrowing across compliance periods would introduce."[188] EPA expresses a general concern about borrowing because the Agency is proposing to record allowances for one compliance period at a time and proposing to only allow a state to replace the mass-based trading federal plan with a state plan if the Agency has not yet recorded allowances in source accounts.[189] EPA is concerned that it would need to determine how to remove borrowed allowances from circulation to prevent inflation of allowable emissions.[190]

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[185] *See id*. at 64,828-29
[186] *See also id.* at 65,014 ("The EPA notes that the proposed multi-year compliance periods inherently provide the flexibility to emit at relatively higher amounts in earlier years of a given compliance period by using allowances from future years within each compliance period.")
[187] *See id.* at 64,826 (allowing the emission goal to be met on an 8-year average or cumulative basis); *see also id.* at 64,868 (stating that it is possible for states to remedy shortfalls from a prior compliance period such that the revised plan would reflect BSER over the cumulative compliance period).
[188] 80 Fed. Reg. at 65,014
[189] *Id*.
[190] *Id*.

If a state replaces a mass-based federal plan with a rate-based plan, EPA can prevent the inflation of allowable emissions by converting the allowance debt to an ERC debt or converting the number of allowances to a corresponding number of ERCs (or it could require the state to do so). *See* Section V.A. above, describing a mass to rate exchange. The Agency could require approvable plans to have mechanisms that prevent double-counting or inflation. Crafting such a solution would not be difficult, and EPA has not provided any reason not to do so.

C. All Biomass Should Be Treated as "Qualified" and No Emissions Attributed to Biomass Should Require Allowances.

EPA's Proposed Trading Plan Rule says very little about the treatment of biomass under a mass-based plan. Indeed, the full extent of EPA's preamble discussion is a request for comment on "the appropriateness of the biomass treatment requirements offered for comment in [the rate-based section] of this preamble in the context of a mass-based set-aside."[191] This limited discussion suggests that EPA has not given this important issue the full consideration it deserves. Nevertheless, for the same reasons discussed above with respect to the treatment of biomass under a rate-based plan, biomass-based generation should be treated as qualified RE generation under a mass-based plan and as a zero-emitting generation source. *See* section VI.D.2. above. As such, no emissions attributed to biomass firing should require allowances. Further, although APPA believes that the Agency has not justified the use of the leakage-based set-asides, as discussed below in section VII.D., firing with biomass should qualify for allocation of allowances from the RE set-aside to the extent that set-aside is implemented.

[191] *Id*. at 65,023.

D. Leakage Is Not a Sufficient Justification for Creating RE and the Output-Based Set-Asides.

The Proposed Trading Plan Rule notes that the Section 111(d) Rule "specified that mass-based plan approaches must address leakage."[192][193] The mere fact that EPA believes it must address leakage demonstrates how far the Proposed Trading Plan Rule has strayed from the requirements of CAA Section 111(d). EPA's requirement that states address leakage reveals that the Agency has not truly established performance standards for individual EGUs.[194] If it had, it would make no difference to overall environmental goals whether individual affected EGUs shut down, curtailed operation, improved performance, or purchased allowances. Instead, EPA's leakage provisions verify that the Agency has a clear vision for how the power sector should operate, and that it is using the Section 111(d) Rule to translate that vision into reality. This sort of economic restructuring exceeds the authority granted to EPA under Section 111(d) of the CAA.

EPA's proposal to address leakage, moreover, does not square with the position it has taken in the related Section 111(b) rule for new, modified, and reconstructed sources. Indeed, if the Agency's statements in that final rule are to be taken seriously, provisions to address leakage should not be necessary at all. Specifically, in the Section 111(b) rulemaking, commenters argued that performance standards for new sources should not be less stringent than standards for existing sources and that the proposed Section 111(d) Rule was, in fact, more stringent than the Section 111(b) proposal. EPA responded to these comments by disputing this notion and in fact

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[192] The final Section 111(d) Rule defined leakage as "the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER." 80 Fed. Reg. at 64,977-78.
[193] 80 Fed. Reg. at 64,978.
[194] *Id*.

argued that the Section 111(b) and (d) standards cannot even be compared due to differences in timing, compliance flexibility, and applicability.[195] If this is the case, and there is no basis for concluding that new sources are subject to more permissive standards than existing sources, then there is no basis for EPA's claim that implementation of the Section 111(d) Rule will incentivize existing EGUs to shut down and shift generation to new sources governed by Section 111(b) instead. In short, there is no reason to think that leakage will occur. Because EPA's positions in the Section 111(b) rule and the Proposed Trading Plan Rule are internally consistent, the Agency's action is arbitrary and capricious.

Even if EPA could reasonably address leakage, it has failed to establish that its proposed method for doing so in the Proposed Trading Plan Rule is rational. The Agency proposes to address leakage by creating "allowance allocation approaches…, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE."[196] EPA has included some details regarding how the set-asides will operate.[197] Nowhere in the Proposed Trading Plan Rule, however, does EPA provide an analysis demonstrating why its choices make sense, are superior to other options, or even that they will be effective at preventing leakage. In the Allowance Allocation Proposed Rule TSD ("Allocation TSD"), for instance, EPA states that "[t]he size of the set-aside is determined *by assuming* that it would incentivize all existing NGCC in the state to increase their utilization to a 60 percent capacity factor."[198] The Agency's additional analysis, described in the RIA for the Proposed Trading Plan Rule, also suffers from serious limitations.[199] As EPA acknowledges, it did not, in

[195] 80 Fed. Reg. at 64,785-87
[196] 80 Fed. Reg. at 64,978.
[197] *Id.* at 65,020-25.
[198] Allocation TSD at 7 (emphasis added).
[199] RIA at 1-32 to 1-33

fact model the mass-based scenario with the set-asides included, and its limited analysis does not consider "important aspects of power markets," like changes in relative fuel and allowance prices.[200] These are critical factors. Similarly, the Agency A's Renewable Energy (RE) Set-aside TSD (RE TSD) provides only limited analysis and explanation of EPA's reasoning as to the proposed size of the RE set-aside. Indeed, the RE TSD shows EPA has simply made a variety of assumptions about how to determine the size of the RE set-aside, including the cost of allowances and the incentives needed to make RE competitive, without analyzing whether the set-aside will in fact prevent leakage.

The Agency should take a more judicious approach. A program to address leakage should only be included if analysis demonstrates that leakage *will* occur and that it *will* result in significant overall CO_2 emission increases. Absent a demonstration that leakage will occur, inclusion of such leakage provisions is unsupported and potentially harmful.

If EPA proceeds to finalize its leakage-based set-asides, it should make several key changes to its proposal. The Agency notes in the allowance distribution section of the preamble to the Proposed Trading Plan Rule that states can submit partial plans to take over only the allowance allocation portion of a mass-based plan. EPA states that such partial plans must either address leakage through adoption of the set-asides or otherwise demonstrate that the state plan will address leakage or that leakage will not occur.[201] The Agency should provide guidance to the states as to how these demonstrations can be made and should develop "safe harbors" apart from adoption of the set-asides that will also guarantee that states have met their leakage obligation, to the extent EPA can lawfully require such provisions. Along those lines, the

[200] *Id*. at 1-33.
[201] 80 Fed. Reg. at 65,028

Agency should acknowledge that units that shut down because they reach the end of their remaining useful life are not implicated in the Agency's concept of leakage.

Finally, to earn allowances from the RE set-aside, the RE generation must satisfy EPA's qualifying RE requirements. EPA has imported its qualifying RE requirements from the rate-based model trading rules, limiting qualifying RE under the mass-based plan to the same categories of RE projects—wind, solar, geothermal power, and hydropower.[202] For the same reasons expressed above in section VII.D., EPA must provide a broader base of qualifying RE.

E. States Should Be Allowed to Take Over Allocation of Allowances While Otherwise Remaining Subject to a Federal Plan.

EPA should provide the flexibility of allowing states to take over the allocation of allowances while otherwise remaining subject to a federal plan. APPA generally supports the Agency's proposal to include safeguards against market disruption and protect reliance interests when a state seeks to take over allowance allocations after being subjected to a federal plan or seeks to replace a federal plan with a state plan.[203] However, the Agency should perform a case-by-case assessment of the potential for market disruption. States should be given the opportunity to demonstrate that state take-over of allocations will not disrupt the market or disturb reliance interests. This will provide additional flexibility to states and appropriate protection against market and reliance interest disruption.

EPA has not, however, provided a justification for its proposed requirement that states implement the CEIP program as a condition of taking over allowance allocation. The CEIP was intended to be an "optional" program providing "additional flexibility" to states.[204] Imposing a requirement that the state implement the CEIP program runs against the principles of cooperative

[202] 80 Fed. Reg. at 64,994 n.58.
[203] *Id*. at 65,027-29
[204] 80 Fed. Reg. at 64,829.

federalism and EPA's stated intent not to punish states for failing to submit a state plan. If a state chooses to submit a replacement for the federal allocation system, the Agency must allow the state broad discretion in the design of that replacement. Indeed, a state's "broad latitude to design plans that fit their unique circumstances" is one of the factors that EPA touted in the Section 111(d) Rule as supporting reliability and resource adequacy[205] and is a requirement of CAA Section 111(d). EPA has provided no rational basis for requiring states to implement the CEIP if they take over allocations. This lack of explanation in the Proposed Trading Plan Rule provides no basis for finalizing this provision. If the Agency's concern is upending reliance interests in CEIP allowances, then EPA can address those concerns by continuing to implement the CEIP directly as a separate incentive program that does not take allowances from a state's budget, as recommended in these comments.

Finally, as stated in section V.D., EPA has not properly proposed the CEIP, and thus cannot require states to implement the program. The Agency must follow proper procedure and issue an adequate proposal before anyone, including EPA, can reasonably promulgate a plan that includes the CEIP.

F. EPA's Proposal Regarding Allocation of Allowances to Units That Retire Is Unjustified and Insufficient.

For EGUs subject to mass-based plans, EPA proposes to provide only a limited number of allowances to units that do not operate for two consecutive years. After two years of non-operation, "such affected EGU will not be allocated the CO_2 allowances…for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period."[206] Allocations are recorded seven months before the start

[205] Resource Adequacy and Reliability Analysis TSD at 1.
[206] 80 Fed. Reg. at 65,067.

of each compliance period. Thus, depending on when the unit ceases operation and whether it ceases operation during a two- or three-year compliance period, a retired unit could receive allowances, under EPA's proposal, for a total of between three and five years of non-operation, inclusive of the two years of non-operation that EPA proposes to use as the basis for concluding a unit has retired. After that period, the allowances that would have been allocated to the retired EGU would be allocated to the RE set-aside.[207][208]

EPA asks for comment on the number of years for which retired units should continue to receive allowances.[209] In previous EPA rules, the Agency has taken a very different approach to the one it proposes here. Indeed, EPA has consistently allocated allowances to retired units throughout the duration of the trading program at issue. (Promulgating CAMR and explaining that "[r]etired units will continue to receive allowances indefinitely thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations"). [210] EPA's rationale for taking a different approach in the Section 111(d) context is limited. The Agency states only that it believes it has identified "a reasonable middle ground" between incentivizing retirements through allocations to retired units and removing allocations from units that "do not need allowances."[211] This is not a sufficient basis for such an important policy decision.

EPA's proposed one-size-fits all approach is certain to cause problems for certain EGUs and certain states. For that reason, APPA requests that EPA adopt an approach to allocations for retired units that mirrors its proposed approach to allocations in general: The Agency should

[207] EPA has not proposed any incentive for units that retire under a rate-based program. That approach is inequitable and unreasonable from a policy perspective. EPA should propose a crediting mechanism that provides units that retire under a rate-based program with credit equal to that provided under the mass-based program.
[208] *Id*. at 65,026-27
[209] *Id*.
[210] 70 Fed. Reg. 28,606, 26,628 (May 18, 2005)
[211] 80 Fed. Reg. at 65,026

encourage states, through partial plans or delegations of EPA authority to the states, to take over these determinations directly, and EPA should largely defer to the policy choices states make with respect to these issues.

If a state decides not to submit a partial plan of this type, EPA should, instead of promulgating its one-size-fits-all approach, consult with the state and the state's EGUs, propose a retirement allocation approach for that state that reflects the results of this consultation through notice and comment rulemaking procedures, and finalize an approach to retirement allocations that is in the best interest of the state and its EGUs, taking into account the state's projected EGU retirement and growth profile.

Finally, if EPA does ultimately adopt its one-size fits-all approach, when retired units stop receiving their allocations, it should not then allocate those allowances to the RE set-aside for the state in which the retired unit is located. As EPA notes in the Proposed Trading Plan Rule, this approach would "allow the RE set-aside to grow over time," but to what end?[212] The Agency has not provided an analysis demonstrating a benefit from increasing the size of the RE set-aside. Indeed, the point of the RE set-aside is to prevent leakage, and there is no evidence in the record that the threat of leakage will grow over time or that EPA has purposefully designed the set-aside to be too small to adequately address leakage. In fact, as discussed in section VII.D., EPA has not adequately demonstrated the need or effectiveness of its set-asides, and certainly has not made a showing that they should grow larger over time. On the other hand, when units retire, significant emission reductions will be achieved, consistent with the overall goals of the Section 111(d) Rule, and there is no reason why the overall compliance obligations

[212] *Id*.

for the remaining units should not be made at least somewhat less burdensome through the pro rata reallocation of a retired unit's allowances to the remaining affected EGUs.

IX. EPA's Model Trading Rules Do Not Adequately Reflect the Scope of State Discretion.

The CAA defines responsibilities at both state and federal levels, providing for a system of cooperative federalism in which EPA generally sets broad policy goals, like emission guidelines under Section 111(d) of the CAA, and states decide how those goals are to be implemented and applied against individual sources within their jurisdictions. EPA's model trading rules, while on the surface only an option for states to consider, raise concerns related to the CAA's division of labor between EPA and the states. Indeed, while the Agency regularly touts the flexibility available to states to craft appropriate plans to implement the Section 111(d) Rule, in the Proposed Trading Plan Rule, EPA suggests that the model trading rules are, if not compulsory, highly favored and that alternative approaches that might not receive favorable treatment from EPA. The Agency, for instance, "strongly encourages" states to adopt the model trading rules and expects states to reference these provisions in their rulemaking.[213]

Further, even where EPA acknowledges that states have the authority to deviate from the model trading rules, it seeks to require states to include the model trading rule program as a "backstop" to be implemented in the event that the state's preferred approach fails to satisfy EPA's expectations.[214] Indeed, even EPA's repeated emphasis that the model rules are "presumptively approvable" and the suggestion that deviations from the model rules may not be approved could have a chilling effect on state efforts to find creative solutions and compliance

[213] 80 Fed. Reg. at 64,973
[214] 80 Fed. Reg. 64,976.

options.[215] ("If one of the model rules is adopted by a state *without any change*, it would be presumptively approvable.") (emphasis added). These statements appear to suggest that states that do not follow the model trading rules closely will be at significant risk for having their plans disapproved.

EPA must acknowledge that states are free to modify the model rules or adopt a wholly different approach to compliance with the Section 111(d) Rule. Indeed, although many may choose to do so, states are not required to participate in a trading program at all, and the Agency cannot impose a trading program to achieve results that conflict with the limitations of CAA Section 111(d). EPA must make clear that it will defer to state policy decisions on implementation of the Section 111(d) Rule and not second-guess state strategies for achieving the goals EPA has established, even if those strategies are not the strategies it would adopt if it were charged with implementing the Section 111(d) Rule. While the Agency purports to provide states with discretion in the design of implementation plans, states will have to satisfy multiple objectives and respond to a broad range of stakeholder opinions on a cost effective path forward to attain the goals of the Section 111(d) Rule, least of which is the design on the interstate trading program.

A. EPA Should Ensure Wide Accesses to Trading Instruments.

EPA envisions a vastly expanded role for emissions trading, in the form of ERCs in a rate-based plan or emission allowances in a mass-based plan to comply with the final Section 111(d) rule. EPA has a notion that there is significant "headroom"

> i[f emission limits are set at the CO_2 emissions performance rates, affected EGUs in two of the three interconnects on average do not need to implement the building blocks to their full available extent in order to achieve their emission limits (because the performance rates for each source category are the emission

[215] 80 Fed. Reg. at 64,973

> rates achievable by that source category though the application of the building blocks in the interconnection where that achievable emission rate is the highest) providing further opportunities in those interconnects to generate surplus emission reductions that could be used as the basis for issuances of ERCs.][216]

This notion of headroom is flawed, however, as it relies on the assumption that EPA's determination of BSER in the final Section 111(d) rule relies on actions that are not within the control of an individual source and, based on these actions, sets standards of performance that cannot be achieved. Further, neither a NGCC nor coal-fired EGU is capable of meeting a 771 lb/MWh or 1,305 lb/MWh CO_2 emission rate respectively, without generating ERCs or allowances from other sources. EPA states that emissions' trading was an integral part of the BSER analysis.[217] It applies BSER on a regional basis, via the three interconnects, which then created state goals based upon partial emission reductions occurring outside of an affected EGU's own state. APPA disagrees with this methodology to support the Section 111(d) Rule's compliance obligation.

EPA points to several other emission trading programs for criteria pollutants, like the CAA Title IV Acid Rain Program, NOx Budget Trading Program, Clean Air Interstate Rule (CAIR), and Cross State Air Pollution Rule (CSAPR), as examples of trading programs widely used by the electric utility industry to meet environmental performance objectives. However, these programs have not been implemented at nearly the scale or complexity as proposed in the federal plan and model trading rules. Previous EPA-administered emission trading programs included predetermined groups of states and relied on commercially demonstrated emission control technology.[218] Participants in those EPA emission trading programs often switched fuel

[216] 80 Fed. Reg. at 64,732 (October 23, 2015).
[217] *Id*. 64,735
[218] Dallas Burtraw and Sarah Jo Szambelan, Resources for the Future, U.S. Emissions Trading Markets for SO_2 and NOx (October, 2009).

to meet an emission target instead of buying allowances or installed flue-gas desulfurization (FGD) technology. Thus, this previous behavior supports the notion that for Section 111(d) Rule compliance, utilities will discontinue operating their coal-fired plants and build new NGCC and utility-scale wind and solar resources and forego or limit their participation in an emissions trading market. The lack of a well-formed emissions trading market increases compliance costs for affected EGUs in general and in particular for public power utilities meeting the definition of a small business under SBFEFA.[219] More than 90 percent of public power utilities qualify as small businesses under SBREFA, underscoring the significance and concern small entities have regarding their ability to effectively participate in an emissions trading market.

Given the huge importance of cost-effective trading programs to Section 111(d) Rule compliance, APPA commissioned a report to evaluate the compliance burdens created for two representative public power utilities. The first illustration focused on a single-coal fired EGU that serves load in several municipalities and lacks access to other generation resources, including renewables. The second represents a mixed-resource (i.e., hydro, renewables, fossil, and energy efficiency) joint action agency that owns coal-fired generation in one state and serves load in multiple states, but not in the state in which the affected EGU is located. Both scenarios were evaluated to identify compliance gaps associated with meeting the final Section 111(d) rule's performance goals under the Proposed Rule. The analysis concludes that large-scale interstate trading will better provide individual EGUs the flexibility to determine the best compliance strategy at the lowest cost. That strategy might include operating at a lower capacity factor, developing EE programs, deploying new renewable resources, acquiring ERC or allowances, or all-of-the-above options. APPA takes no position on the appropriate allowance

[219] Small entities are defines as governments of cities, counties, towns, townships, villages, school districts, or special districts with populations of 50,000 or less.

allocation methodology a state may choose to employ. However, we offer this study as a qualitative assessment of emissions trading under certain scenarios.

B. Rate-Based Compliance Pathway for a Single Coal Fired EGU.

First we turn to the compliance gap created for a single coal fired EGU, where this facility does not have the flexibility to rely on other units and the potential for stranded costs is high.[220] The analysis first looked at a rate-based statewide goal verses a subcategorized goal and determined the ERC deficit for this EGU was greater under a subcategorized rate-based state plan. This particular EGU is located in Texas where its subcategorized rate is 1,305 lb CO_2/MWh versus its 1,042 lb CO_2/MWh statewide rate. Selecting a subcategorized rate requires less ERCs to be generated for compliance on an annual basis.[221] However, the benefits diminish when the subcategorized rate is close to the statewide rate, such the case in Montana, North Dakota, West Virginia, and Wyoming. Under the Proposed Rule, the impact to the EGU was identical to the subcategorized rate-based state plan because under either case, this EGU has no ability to generate ERCs vis á vis consumer-side EE projects.

The proposed rate-based federal plan offers no pathway for EE ERCs, creating a disincentive to deploy EE to offset CO_2 emissions from affected EGUs participating in a rate-based federal plan trading program, which is contrary to the goal of reducing CO_2 emissions. ERCs generated through EE projects, such as demand-side EE can meet the same rigorous EM&V protocols specified in the REC markets, thus including EE as a compliance path in a rate-based federal plan is appropriate. APPA believes EPA's development of a rate-based federal plan should provide equity between the treatment of EE in both a rate-based federal plan and a

[220] Comments of the Texas Municipal Power Agency (TMPA) 80 Fed. Reg.64966, EPA-HQ-OAR-2015-0199, October 23, 2015.
[221] Energy Strategies, "Compliance Scenarios under the EPA Clean Power Plan", pg. 26, December 23, 2015.

rate-based state plan, allowing for maximum compliance flexibility. EE is often regarded as the lowest cost measure compared to the deployment of new nuclear or new renewable resources. If the ability to generate ERCs from an EE project is not available in some or many state plans, market liquidity is limited, resulting in increased compliance costs and forcing the re-dispatch of NGCC generation.

Based upon this illustration, a single coal-fired EGU located in Texas would have to procure or generate approximately 14-27 million ERCs from RE or EE projects, depending on whether a state plan adopted the subcategorized or statewide-emission rate.[222] If the EGU sought to meet its compliance obligation with a renewable resource operating at a 40 percent capacity factor, then 661 MW of new renewable resources are needed to meet 2030 goals under a subcategorized performance rate federal plan.

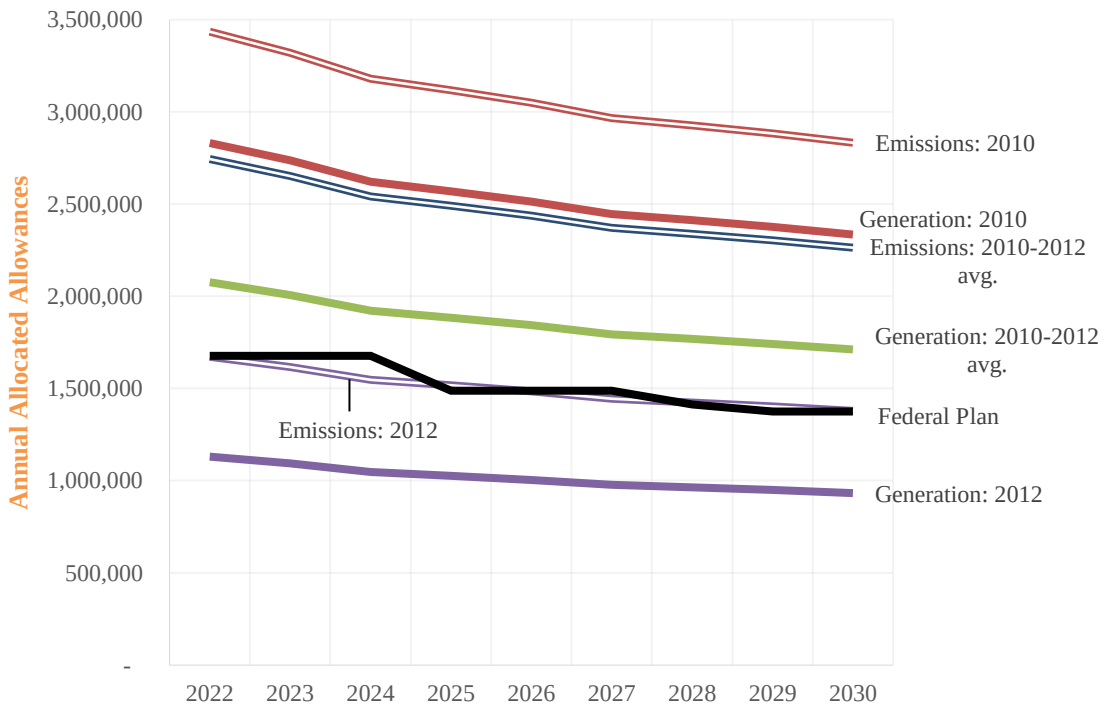
C. Mass-Based Compliance Pathway for a Single Coal Fired EGU.

Under a mass-based compliance pathway for the single coal-fired EGU, the compliance gap is best illustrated through varying allowance distribution methodologies. This particular EGU would receive the most allowances if the allocation methodology distributed allowances based upon 2010 emissions and the fewest allowances based upon 2012 generation, as noted in Figure 3.[223] Assuming the EGU continues to operate at a 75 percent capacity factor, it would require approximately 3.5 million allowances per year to operate based upon 2010 emissions levels with no set-asides, and 22 million allowances are needed if the allocation was based upon 2012 historic emissions. This wide range further shows how integral the design of the allocation methodology is to maximizing the number of allowances allocated to an EGU. Under these

[222] Energy Strategies, "APPA Compliance Scenarios under the EPA Clean Power Plan," December 23, 2015 at p. 30.
[223] *Id*. at page 34

circumstances, the EGU would have to procure allowances or reduce generation to a level equivalent to assigned allowances or a combination of the two.

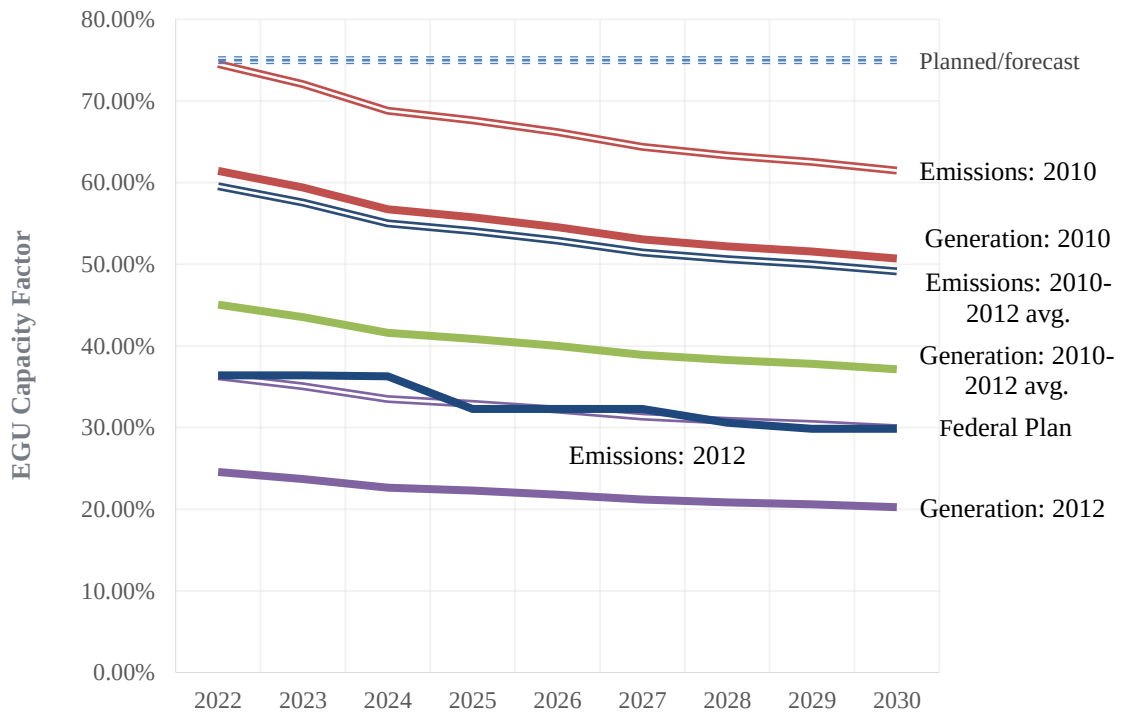
Figure 3: Impact of Varying Allowance Allocation Methods



Depending on the allocation methodology chosen, this particular EGU, and many others like it, may be forced to reduce generation in order to continue to operate at required load and within the confines of the allowances allocated to the source. The reduction in generation, as a compliance measure, is untenable for public power communities with only one based-load resource to call upon in a limited trading market. Figure 4 illustrates the impact of modeled allocation methodologies on the representative EGU's capacity factor. Here we see the reduction in generation is limited if allowances were allocated based upon 2010 emissions. The reduction in generation is more severe where emission allowances are distributed based upon 2012 operations. Allocations based upon the federal plan proposed methodology with set-asides

results in capacity factors below 30 percent in 2030. This analysis is provided to further demonstrate the compliance burden a single coal fired EGU could experience, if it only had access to allocated allowances and no other allowances were available from the market.

Figure 4: Re-dispatch as a Compliance Measure

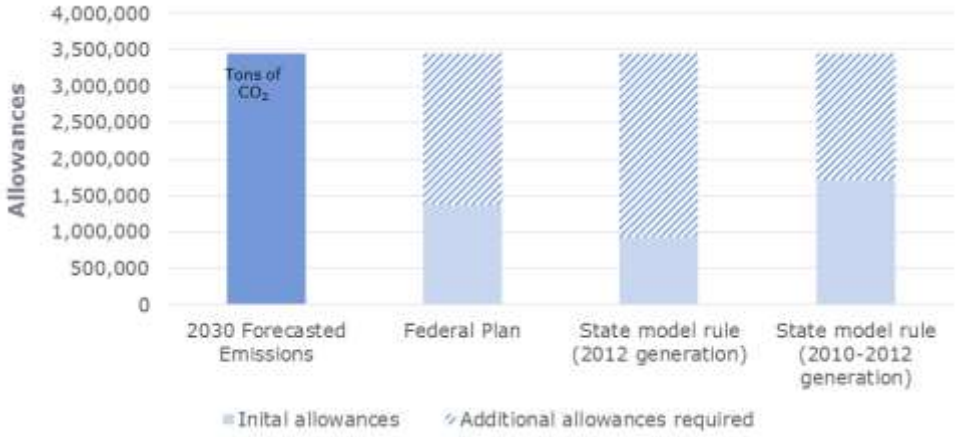


The proposed mass-based federal plan establishes prescribes allowance set-asides that reduce the amount of allowances that would be distributed to an EGU based upon its average historical generation. In the federal plan context, it is clear set-asides have an impact on a single coal-fired EGU. Figure 5 depicts that 1.4 million allowances are allocated to this representative single coal-fired EGU in 2030 based on historical average generation from 2010-2012 under a federal plan with the three set-asides. Under a state plan with no set-asides using the same basis, 1.7 million allowances are distributed to this EGU. This example assumes no set–asides under a state plan. However, a state is free to create set-asides that may be larger, smaller, or simply different than those prescribed in the proposed mass-based federal plan.

Figure 5: EGU Allowances Allocation Comparison (2030 Only)

Figure 6 illustrates the additional allowances required under three allowance distribution methodologies: a federal plan, a state plan with no set-asides based upon 2012 generation, and a state plan with no set-asides based on average 2010-2012 generation. This example highlights the impact of a set-aside can be more significant that the choice of allocation methodologies.

Figure 6: Impact of Allowance Distribution Methodologies



As mentioned in section VIII. E. and F., EPA must conduct a full notice and comment period for each state that receives a federal plan, allowing stakeholders the opportunity to

comment on set-aside design and allowance distribution methodology. APPA supports SBA's Office of Advocacy's comments calling for "EPA to re-propose a federal plan for each state that fails to submit a state plan or an approvable plan, and to develop a supplemental initial regulatory flexibility analysis."[224]

A coal plant becomes uneconomical to operate if there is no interstate trading of ERCs or allowances. Compliance for this EGU can only be achieved by other market participants and though the existence of a wide and deep emissions trading market.

D. Rate-Based Compliance Pathway for a Mixed-Resource EGU.

As noted previously, the second scenario analyzed represents a "mixed-resource" EGU with access to RE and EE compliance measures in a state other than where the affected EGU is located, thus making its ability to trade ERCs critical to meeting the state's emission goal. The mixed-resource EGU is located in Wyoming where its subcategorized rate and statewide rate are similar, thus there is limited benefit associated with adopting a statewide rate of 1,299 lb CO_2/MWh when trading pathways under a subcategorized rate state plan are considered by EPA as "trading ready."

Looking at compliance for a mixed-resource EGU through the lens of a rate-based federal plan is problematic, as it may not offer as much flexibility as required. Based upon modeling, the mixed-resource EGU's 2030 cumulative ERC requirement would be 8.6 million, under a federal plan if the EGU is unable to generate credits vis á vis EE, versus 4.5 million under a rate-based state plan. APPA calls upon EPA to provide equal treatment of EE under rate-based federal and state plans. If an EGU is able to apply its out-of-state EE and renewable resources to

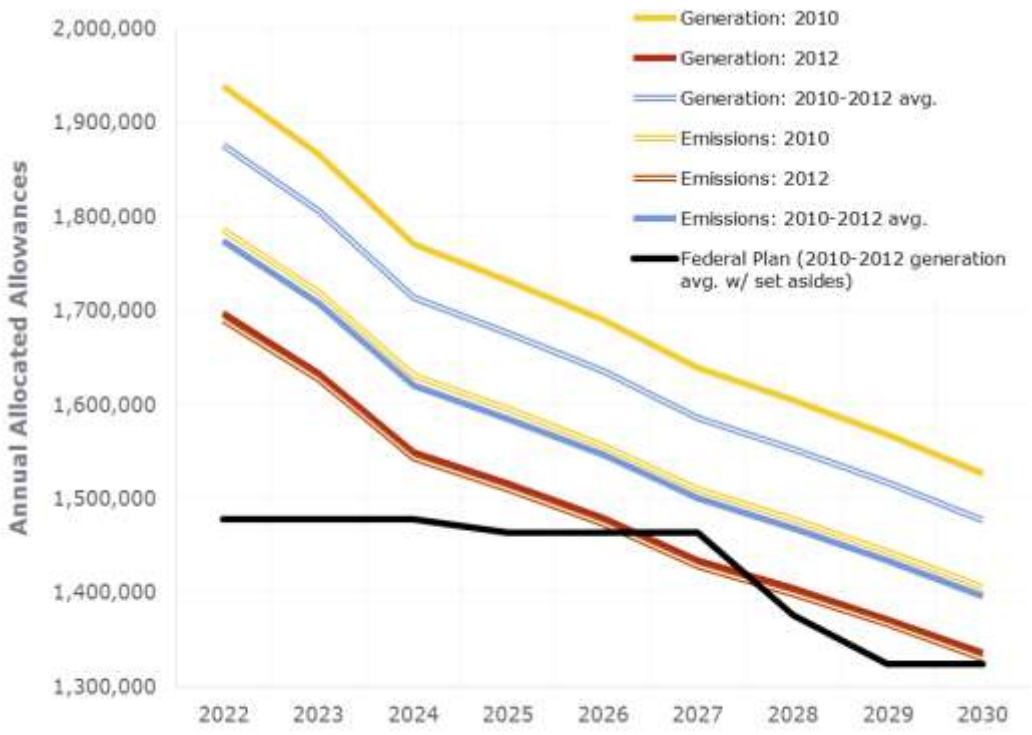
[224] SBA Office of Advocacy Comments on EPA's "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations" (Docket No. EPA–HQ– OAR–2015–0199), December 21, 2015.

an EGU's emission rate, the compliance burden is minimize while still meeting the program objective to reduce CO_2 emissions while providing flexibility.

E. Mass-Based Compliance Pathway for a Mixed-Resource EGU.

Under a mass-based compliance pathway, the mixed-resource EGU suffers many of the same challenges as a single coal-fired EGU. The proposed federal plan set-asides reduce the pool of available allowances, even in Wyoming where there is a smaller pool of out-put based allocations for NGCC. Coal units are still impacted due to the set-asides. The modeling conducted based upon the varying allowance distribution methodologies for a mix-resource EGUs shows the federal plan penalizes this EGU by creating the fewest number of allowances allocated on an annual basis (see Figure 7). The incremental allowance requirement beyond those already assigned, assuming the EGU continued operating at a 75 percent capacity factor under a federal plan is 7.3 million and approximately 4.9 million under a state plan without set-asides based upon 2010 historical generation. It should be noted that none of the state plans investigated included set-asides. However state Section 111(d) compliance plans may ultimately incorporate set-asides to address leakage or other state-driven policy decisions. If a state plan were to include set-asides, then the number of cumulative allowances required through 2030 would be understated.

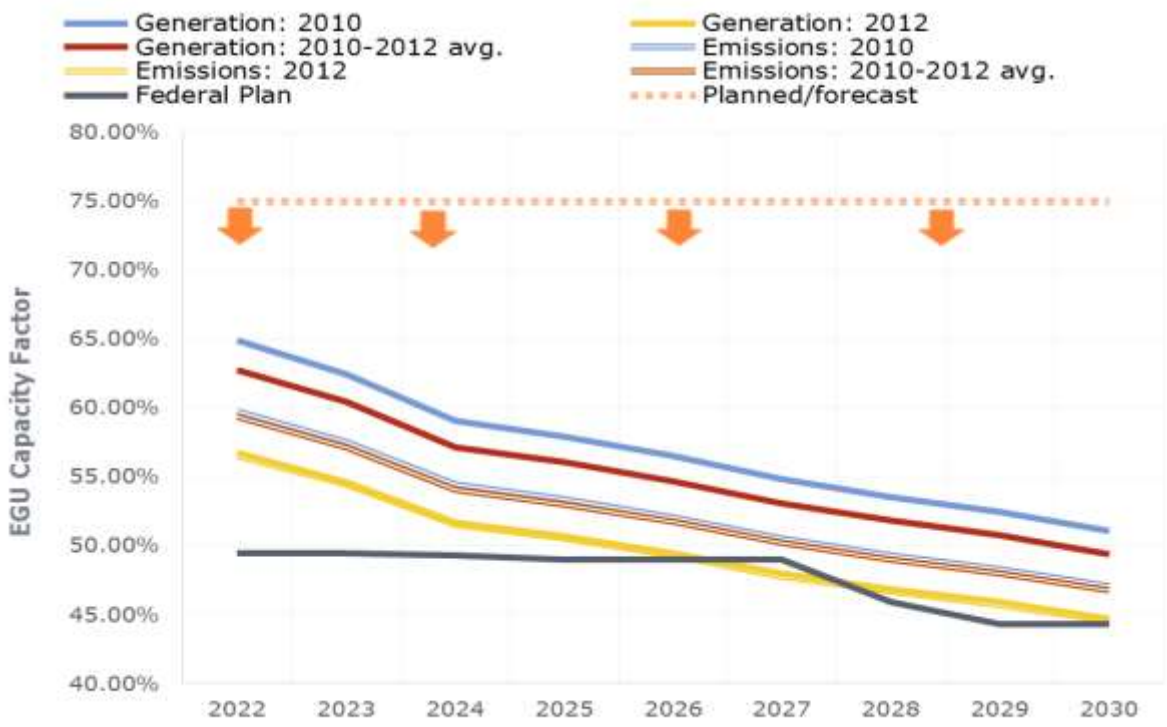
Figure 7: Impact of Varying Allowance Allocation Methods



The prospect of re-dispatching generation for a mixed-resource EGU to comply with the final Section 111(d) Rule by 2030 presents several uneconomic situations. In the 2030 timeframe, the most serve reductions in generation are required under a federal plan, and under a state model rule plan in which allowances are distributed based upon 2012 historical generation or emissions, as illustrated in Figure 8. The EGU would have to operate slightly above a 45 percent capacity factor in order for its emissions not to exceed the number of allocated allowances.[225]

[225] Energy Strategies, "APPA Compliance Scenarios under the EPA Clean Power Plan", December 23, 2015 at 54.

Figure 8: Re-Dispatch as a Compliance Measure



EPA's final Section 111(d) Rule seems to promote a mass-based trading scheme that effectuates national CO_2 resource planning of the entire electric utility sector. The decision to implement a rate- or a mass-based plan will be a seminal decision for each state that may or may not lead to an operable trading market. EPA should promulgate both a rate- and mass-based federal plan for states that fail to submit a plan or when the plan is not approvable.

X. The Implications of Other EPA Programs and Rules on Compliance with Federal and State Plans.

The unprecedented nature and expansive reach of EPA's Section 111(d) Rule and Proposed Rule does little to harmonize compliance deadlines and environmental goals of other EPA Rules and programs. One such example is the recently finalized Effluent Limitation Guidelines for Steam Electric Generating Units (ELG Rule). The ELG Rule requires compliance with new wastewater discharge limitations "as soon as possible" for FGD waste water, gasification waste water, fly ash transport water, flue gas mercury control wastewater and bottom ash transport water beginning November 1, 2018, but no later than December 31, 2023.[226] The ELG Rule was promulgated without the benefits of stakeholder feedback on the impact of the Section 111(d) Rule on the ELG Rule. The Section 111(d) Rule was still nascent when APPA filed its ELG comments. (The proposed 111(d) Rule was published in the Federal Register on June 18, 2014, more than seven months after the close of the ELG comment period. Moreover, a supplemental 111(d) rule proposal was published in November 2014, as well as a notice of data availability.) There are other federal rules which create substantive and challenges to implementing EPA's Section 111(d) Rule discussed below. APPA recommends states and affected sources seek to streamline and harmonize many of these environmental requirements in order to limit consumer impacts.

A. Implications of the New Source Review (NSR) Program on Section 111(d) Compliance Under a Federal Plan.

In its Proposed Rule, EPA recognizes the potential for new source review (NSR) consequences from implementing Section 111(d) Rule Building Block 1. However, EPA dismisses the NSR-related concerns of commenters and small entities by stating that it expects

[226] 80 Fed. Reg.67,854 (Effluent Limitation Guidelines and Standards for Steam Electric Generating Point Source Category, (November 3, 2105)

there will be "few instances" where "an NSR permit would be required" in its proposal.[227] APPA believes that EPA is underestimating the need to alleviate the conflict of interest that the NSR program creates for CO_2.

Because a state may require an affected EGU to undertake physical or operational changes to improve unit efficiency as part of its CAA Section 111(d) plan, APPA believes the EPA ultimately wants power plants to become more efficient as a way of reducing CO_2 emissions. Unfortunately, due to the unaddressed conflicts created between NSR program and the Section 111(d) Rule, generators are stuck contemplating the consequences of becoming more efficient in their operations. Efficiency improvements ultimately increase an EGU's ability to be dispatched, and therefore may result in an increase in the unit's annual emissions, causing potential NSR violations as a result of good faith compliance efforts.

If the emissions increase associated with the EGU's changes exceeds the NSR thresholds for one or more regulated NSR pollutants, the changes would trigger NSR. Further, if CO_2 emission increases exceed the NSR significance level, they too will be subject to Best Available Control Technology (BACT) review. It is therefore critical that the federal plan recognize the importance of streamlined permitting programs to accommodate NSR for major modifications at power plants for non-routine changes, including energy efficiency improvements that may result in increases in GHG emissions. Therefore, APPA urges EPA to use its discretion in the federal plan to prevent NSR from creating a disincentive for plants to make efficiency upgrades and maintain their investments in combustion and related equipment.

While APPA agrees with EPA that the U.S. Supreme Court's opinion in *UARG* v. *EPA*[228] means that "GHG-only" new sources cannot trigger NSR, significant emissions increases that

[227] 80 Fed. Reg at 64,985

result from major modifications of an EGU for other pollutants could trigger BACT review for GHG increases. Since the Supreme Court also remanded to EPA for additional rulemaking on the GHG "significance level" that will trigger GHG BACT review for other NSR-affected changes, including non-routine maintenance and energy efficiency projects, more GHG BACT review must be contemplated and is needed. For EPA's federal plan to be workable it must recognize that increases in emissions of GHGs from so-called "anyway sources" may occur. The Agency should provide for growth in NSR emissions if the overall state GHG reductions are being achieved as required by the state plan. Without addressing the complicated "anyway sources" emissions in elements of the federal plan and providing protection for EGUs undertaking efficiency improvements, there would be an absurd result of EGUs attempting to comply being penalized for improving environmental performance.

For public power entities, this is particularly important. If an entity triggers NSR, they should be given a fast-track path to compliance. This could include a special streamlined permitting process that puts the entity at the front of the queue and a process which provides streamlined BACT and permitting review for EGUs. Allowing utilities to offset increases in GHG and other emissions to legally avoid Prevention of Significant Deterioration (PSD)/NSR review should be promoted by EPA as another avenue for ensuring maintenance of a unit's EE. Similarly, internal netting of GHG and other emissions will serve an important role in preserving EE and well-maintained units. Just as EPA should ensure that states are aware of the importance of maintaining these programs in their state plans, federal plans must also include NSR provisions.

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[228] 134 S. Ct. 2427 (June 23, 2014)

1. APPA Believes EPA's Assertions Regarding NSR in the Federal Plan Are Incorrect and Should Be Reconsidered.

EPA must ensure that NSR provisions in federal plans take into account GHG increases from new and modified projects. Equally important, the Agency must ensure that EGUs that are undertaking efficiency improvements and other non-maintenance projects to preserve their investments are not penalized in the federal Section 111(d) compliance plan. APPA disagrees with EPA's assertion that most plants will not be affected by NSR under the Section 111(d) Rule, particularly since EPA is reconsidering a lower GHG significance level that will trigger BACT review than the one currently in place. (See discussion of remand of the GHG significance level pursuant to the *UARG v. EPA* decision, supra.) As stated above, NSR can be a critical permitting issue for utilities to maintain and enhance energy efficiency, maintain the reliability of newer equipment, and incentivize continued conversion of combustion equipment to newer technologies. All of these changes typically result in NOx and carbon monoxide increases, which also may result in increases in carbon monoxide and nitrogen oxides and therefore may trigger BACT review for GHGs.

In addition to retrofits of coal-fired boilers to natural gas and natural gas combined cycle-fired equipment that can trigger NSR because of increases in NOx and CO emissions, APPA is concerned that historic efficiency improvements and other non-routine maintenance may cause an increase in CO_2 emissions that could trigger GHG BACT review. Below is a chart that shows various EGU efficiency improvements that could continue to be implemented at newer cleaner combustion equipment and the alleged compliance issues raised by EPA in its enforcement actions against utilities based on these same improvements:

Table 1: Technology Assessment Modified and Existing Source Heat Rate Improvements for Existing Coal-Fired EGUs and ICI Boilers That May Require GHG-BACT Review

Efficiency Improvement Technology	Description	Reported Efficiency Increase	APPA Identified EPA Alleged Compliance Issue
Combustion Control Optimization	Adjustment of coal and air flow to optimize steam production for the generator can be done manually or through automated and/or digital software programs (and upgrades).	0.15-0.84% EGU water pressure (WP)-28 Instrumentation adds up to ~3% ICI WP- 8	EPA NSR complaints routinely assert that any change to an analogue system to adjust air flow into a boiler optimizes steam production, enabling the unit to burn more fuel, triggers NSR review because they are physical changes to the boiler and changes in the method of operation of a boiler that are not routine. EPA has alleged that such changes include software-based optimization systems and digital control systems. Sierra Club also has asserted in various other NSR actions against APPA members that program updates for existing digital controls also trigger NSR, as these also are changes in the method of operation that optimize the amount of fuel that can be burned in a unit, thus significantly increasing emissions of SO_2 and NOx.
Cooling System Heat Loss Recovery	Recovery of a portion of the heat loss from cooling water exiting the steam condenser	0.2 to 1% EGU WP 28	Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation thorough a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser. Replacement and rebuilds of condensers are generally always identified by EPA as alleged NSR violations. Replacement of the cooling tower fill has not, to our knowledge, been identified as an alleged NSR violation.
Replace/ Upgrade Burners	Older, wrongly sized, or mechanically deteriorated burners are typically inefficient. Inoperable	Up to 4-5% ICI WP – 8	From the initial November 3, 1999, NSR utility enforcement initiative action filed by U.S. Attorney General Janet Reno against eight IOUs and TVA, to the present NSR actions against utilities and nearly every other industry sector in the U.S., EPA has asserted that addition and/or

Efficiency Improvement Technology	Description	Reported Efficiency Increase	APPA Identified EPA Alleged Compliance Issue
	dampers, broken registers, or clogged nozzles will render an otherwise good burner into a poor performer. These inefficiencies result in incomplete combustion (high carbon monoxide (CO) emissions and unburned carbon) and the need for high excess air.		replacement or upgrading burners in any type of boiler resulted in a significant emissions increase from the unit requiring PSD review. http://www2.epa.gov/enforcement/coal-fired-power-plant-enforcement Eleven (11) burner upgrades and replacements were alleged to have violated NSR in the first nine utility enforcement cases. Note also that even installation of low-NOx burners, a pollution prevention device, is not exempt from NSR if it increasing the efficiency of a boiler. *See New York v. EPA, 433 F.2d 3* (D.C. Cir. 2005), cert denied.
Flue Gas Heat Recovery	It may be possible to recover heat lost when flue gas exits the boiler by installation of a condenser exchanger to heat preheat boiler feedwater.	0.3 to 1.5% EGU WP 28	EPA has routinely identified the installation of condensers to recover flue gas as a physical change to the combustion unit that increases the capacity of a boiler and triggers NSR from resulting increases in SO_2, NOx, and CO.
Air Preheaters and Reheaters	For most fossil fuel-fired heating equipment, energy efficiency can be increased by using waste heat gas recovery systems to capture and use some of the heat in the flue gas. Heat recovery equipment includes various types of heat exchangers (economizers and air heaters), typically located after the gases have passed through the steam generating sections of the	~1% per 40 degree temp. decrease up to ~ 4% ICI WP 9	Heat recovery also includes installation of air preheaters, as well as changes in design of preheaters, including baskets in a preheater. These physical changes and modifications, EPA and Sierra Club assert, are not routine changes or maintenance and thus trigger NSR because they increase or recover lost capacity from a boiler, resulting in increased emissions that trigger NSR review.

Efficiency Improvement Technology	Description	Reported Efficiency Increase	APPA Identified EPA Alleged Compliance Issue
	boiler.		
Economizers – Replacements or Re-tubing	An economizer preheats condensed feed water recycled back to the boiler tubes to the boiler enabling the boiler to heat water more efficiently, increasing output, including air emissions, as a result of increased output.	40 degree decrease in flue gas temp = ~1% ICI WP 8-9	The cost of a new economizer can exceed the cost of $2.3 million for a large boiler according to EPA's EGU and ICI Whitepapers. Replacement of portions of an economizer tubing, typically exceeds $100,000 and is not considered routine maintenance because they are neither frequent nor "like kind replacements," typically involving installation of higher grade chemical resistant coating. Economizer replacement and economizer tubing replacement are cited in nearly every complaint EPA or any citizen has ever filed against an electric utility. NSR violations for economizer installations, repairs, and replacements were alleged 37 times in the first nine NSR enforcement cases brought by EPA**.**
Feedwater Heaters and Improvements	Using other heat sources for the feedwater heater avoids the need to extract steam from the turbine allowing the steam to be used for electric power generation	Discussed on p. 34, but does not specify efficiency improvements.	Increases the output of the steam cycle, in turn increasing the output from the boiler. EPA has alleged that feedwater heater replacement and new installation are not done frequently, and boosts output or restores lost capacity, which triggers NSR review.
Cooling System Heat Loss Recovery	Recovery of a portion of the heat loss from cooling water exiting the steam condenser	0.2 to 1% EGU WP 28	Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation thorough a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser. Replacement and rebuilds of condensers are generally always identified by EPA as alleged NSR violations. Replacing the cooling tower fill has not, to our knowledge, been identified as an alleged NSR violation.

Efficiency Improvement Technology	Description	Reported Efficiency Increase	APPA Identified EPA Alleged Compliance Issue
Flue Gas Heat Recovery	Recovery of the heat lost when flue gas is sprayed with flue gas desulfurization (FGD) reagent slurry and cools	0.3 to 1.5% EGU WP 28	Recovering lost energy in the flue gas to preheat boiler feedwater via use of a condensing heat exchanger has been alleged by EPA to violate NSR because it increases potential output from the boiler.
Low-Rank Coal Drying	Drying of subbituminous and lignite coals using waste heat from flue gas and/or cooling water systems	0.1 to 0.65% EGU WP 28	"Low rank coal drying" has not nominally been alleged as an efficiency improvement that triggers NSR in enforcement actions. However, general modifications of coal handling systems to dry coal to make it easier to handle, convey, and pulverize, improving the overall efficiency, have generically been described in a number of EPA NSR complaints and EPA CAA requests for information utilized by the Agency in preparation of NSR enforcement actions.
Sootblower Optimization	Intermittent injection of high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces to maintain adequate heat transfer	0.1% to 0.65% EGU WP 28	Sootblowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer. The identified technologies include intelligent or neural-network sootblowing (i.e., sootblowing in response to real-time conditions in the boiler) and detonation sootblowing. Sootblowing has been alleged by the Sierra Club to violate state and federal opacity standards, as well as NSR for particulate.
Steam Turbine Design	Maintain mechanical and physical condition of steam turbine use of efficiently designed turbine blades and stead seals	0.84-2.6% EGU WP-28	The most notorious of the Clean Air Act NSR cases alleging PSD/NSR violations for replacement and upgrades in high pressure section of two steam turbines involved retrofit of a Detroit Edison turbine with a GE dense pack (rotor and blades). Starting with the initial complaints against Cinergy and TVA in 1999, the replacement turbine blades are alleged to violate NSR. In the TVA action, EPA experts testified that changes in

Efficiency Improvement Technology	Description	Reported Efficiency Increase	APPA Identified EPA Alleged Compliance Issue
			the composition material and/or design of turbine blades (also known as "buckets") results in increased emissions as a result of increasing the potential output from the associated boiler. They also testified that such changes are non-routine, not "like kind changes," that generally exceed $100,000 in cost. *See EPA legal analysis of NSR impacts at:* http://www.sagady.com/stuff/EPAMonroePlantBrief.pdf

Again, EPA recognizes the potential NSR consequences of implementing Section 111(d) Rule Building Block 1 in the federal plan, but states that the Agency expects there will be "few instances" where "an NSR permit would be required. Clearly these views are not shared by EPA's enforcement arm, as is evident from the Detroit Edison determination and the hundreds of projects targeted in the enforcement initiative since then. Based on the history of EPA's NSR enforcement initiative, which focused largely on efficiency improvements at existing facilities, the Agency's statement that there will be "few instances" in which Building Block 1 projects would trigger NSR prompts concern.

Even if EPA believes there will be "few instances" where an NSR permit would be required, there is no suggestion that all states or citizens share that belief. Citizen plaintiffs have been just as active as EPA in litigating NSR suits over the past fifteen years. Even when those citizen suits have lacked merit, they delay the implementation of any projects including efficiency improvement projects while the complaints are adjudicated or otherwise resolved over a period of years. Therefore NSR is an artifact of EPA's past enforcement and full attention to the attention to the issue in the proposed rulemaking signals additional considerable risk (and

expense) related to all efficiency improvements at existing EGUs. In an enforcement action filed in 2014, for example, EPA sued Oklahoma Gas & Electric Company for allegedly violating NSR even though emissions since the projects have decreased.[229] In this suit, EPA brought these claims following the very same types of upgrades it is now recommending affected EGUs implement under Building Block 1: the replacement of economizers and turbine blades and the addition of heat transfer surface in boilers. EPA should eliminate the threat of protracted NSR litigation and provide a clear statement that any upgrades necessary to implement Building Block 1 do not trigger NSR.

Because EPA's justification of the state emission goals relies on the ability of sources to implement efficiency improvement measures, and because the Agency has failed to propose any credible regulatory provisions to otherwise address this issue, EPA has failed to demonstrate the achievability of its goals as required by Section 111. To remedy this situation, EPA should provide states strong mechanisms, such as those listed in this section to ensure that NSR will not be triggered by efficiency improvements made to comply with a Section 111(d) Rule state or federal plan.

B. Exclusion of Reciprocating Internal Combustion Engines (RICE).

The Section 111(d) Rule and the Proposed Rule appropriately recognize an affected EGU is any steam generating unit (SGU), integrated gasification combined cycle (IGCC), or stationary combustion turbine (SCT) that was in operation or commenced construction as of January 8, 2014.[230] The affected EGU must serve a generator capably of selling greater than 25 MW to a utility power distribution system, having a base rating greater than 260Gj/h (250 MMBtu/h) heat input of fossil fuel, and historically has supplied more than one-third of its potential electric

[229] United States v. OG&E, No. 5:13-cv-00690 (W.D. Okla.).
[230] 80 Fed Reg. at 64,971

output and 219,00 MWh as net–electric sales on any three calendar year basis.[231] Based upon this well understood applicability criteria, it is clear reciprocating internal combustion engines (RICE) do not meet the applicability requirements of an affected EGU under the Proposed Rule. Typically, RICE units are utilized in public power utilities to supply emergency power, voltage support, and demand response all while providing reliability to the bulk power system. Therefore RICE units should be specifically excluded from CO_2 emission reduction requirements under CAA Section 111(d).

XI. Comments on Proposed Amendments to 40 C.F.R. Part 60

A. EPA's Partial Approval Authority Could Create Serious Problems for States.

APPA does not support EPA's proposal, as described in the Proposed Trading Plan Rule, to grant itself authority to partially approve state plans. APPA instead encourages EPA to adopt a more limited role for partial approvals and to adopt limited or conditional approvals to fill the gaps. As explained below, the Agency's partial plan approval, while useful in some contexts, could present significant problems given the complexity of the Section 111(d) Rule and the Proposed Trading Plan Rule.

In the Proposed Trading Plan Rule, EPA proposes to add a new subsection (h) to 40 C.F.R. § 60.27, which provides EPA with the authority to partially approve state plans. Pursuant to this provision, the Agency proposes to make use of partial approval authority in two different ways. First, EPA intends to use this authority "to accept and review a state plan that is only partial in nature, if identified by the state as such, so long as the other applicable submission requirements are met (such as demonstration of legal authority and completion of the public

[231] Id at 64,971

process)."[232] Notably, the Agency proposes to use this partial approval authority to allow states to replace the federal plan allowance-distribution provisions in the mass-based federal plan.[233] APPA believes this use of partial approval authority is appropriate.

EPA also states, however, that partial approval is "a particularly useful function when much of a state plan is approvable and the Agency and the state cannot reach resolution on only a small, severable portion of the state plan."[234] EPA states that if a state "submits what it intends to be a full state plan (rather than just a partial plan), it proposes that the approvable portion of a plan must be functionally severable from the rest of the plan."[235] EPA states that this functional severability test has two components: (1) the approvable portion of the plan must not depend on the rest of the plan (in other words, the disapproval of the remaining portion of the plan must not affect the portion that is approved) and (2) approval of the approvable portion must not alter the function of the submittal in a way that is contrary to the state's intent.[236] APPA opposes this use of the partial plan authority because it could be misapplied. In developing Section 111(d) plans, states will need to make fine-tuned trade-offs between different policy goals and state interests. Changing one small part of a plan could easily unravel key state policy decisions and impose impossible situations on individual EGUs.

To avoid these problems, EPA should instead utilize its limited approval authority or its conditional approval authority in these sorts of situations. Under a limited approval and disapproval, a state's plan would go into effect unaltered, while triggering a future deadline for eventual revision of the plan. EPA and states could use that time to negotiate a fix to whatever

[232] 80 Fed. Reg. at 65,035
[233] *Id*. at 65,027
[234] *Id*. at 65,035
[235] *Id*.
[236] *Id*. at 65,035.

purported flaw the Agency has identified. EPA could use conditional approvals in a similar manner. The deadline for new plans or plan revision under both scenarios should coincide with the beginning of the next compliance period before which a new plan can reasonably be developed and approved. This sort of approach will help to navigate the new areas that the Section 111(d) Rule has opened and provide some safeguards to states and affected EGUs as plans to implement this new and unprecedented program take shape and come into effect.

B. EPA Does Not Have Statutory Authority to Call For Plan Revisions.

EPA cannot finalize proposed 40 C.F.R. § 60.27(j), which would create in the Section 111(d) context "a mechanism for the EPA to make calls for plan revisions similar to the 'SIP-call' provisions of CAA 110(k)(5)."[237] The purpose, structure, and text of CAA Section 111(d) do not authorize a "SIP-call" type requirement.

EPA argues that Section 111(d) authorizes it to adopt the procedures provided for in Section 110. The Agency is called on in Section 111(d) to adopt procedures like those found in Section 110 with respect to the *submission* of state plans, which addresses issues like the timing and review of state submittals. It does not direct EPA to import Section 110 procedures related to plan implementation or revision, which is what the SIP-call provision constitutes. Thus, on its face, EPA has no basis for adopting a Section 110 procedure that would not be related to submittal of a Section 111(d) plan.

Moreover, a SIP-call type procedure would be especially inapposite in the Section 111(d) setting. Section 110 authorizes SIP calls because Section 110 implements the national ambient air quality standards ("NAAQS") provided for under Sections 108 and 109 of the Act. The CAA requires that the NAAQS be reviewed and, if necessary, revised at least every five years.

[237] *Id*. at 64,971

Further, a NAAQS revision has ramifications for numerous other EPA programs and the SIPs that implement them. For those reasons, a SIP-call provision has a clear purpose under Section 110. That purpose does not exist under Section 111(d). Unlike the NAAQS, Section 111(d) emission guidelines cannot be revised.[238]

Due to the significant differences between CAA Sections 110 and 111(d), it is clear why Section 110 needs a SIP-call provision and why Section 111(d) does not. EPA continually reevaluates the NAAQS, potentially changing air quality standards and consequently forcing approved SIPs to be out of date. EPA makes a determination under Section 111(d) only once, so it does not need to update SIPs on a regular basis to include revised performance standards.

C. EPA's Rules Must Provide for Proposal of Federal Plans Before Finalization of Such Plans.

As discussed previously in these comments in section IV.B, EPA must propose individual federal plans prior to finalizing them for each state. The Agency's plan to issue final federal plans without ever proposing those plans violates both the CAA's and the APA's notice requirements. As described in section IV.B, EPA clearly fails to provide notice under either standard, and thus the Proposed Trading Plan Rule does not constitute proper notice of the federal plans. For those reasons, EPA cannot amend 40 C.F.R. § 60.27.

D. EPA Has Abused Its Error Correction Authority in the Past and Should State the Limits of Its Authority Here.

Because EPA has previously misused its authority to correct errors, it should clarify in this rulemaking that its error correction authority is limited. This clarifying language should be

[238] See Comments of the Utility Air Regulatory Group on "Emissions Guidelines and Compliance Times for Municipal Solid Waste Landfills," published at 80 Fed. Reg. 52,100 (Aug. 27, 2015), EPA Docket ID No. EPA-HQ-OAR-2014-0451-0198.

added both to the preamble and the proposed regulatory text for new section 40 C.F.R. § 60.27(k).

In the Proposed Trading Plan Rule, EPA proposes to add a new section (k) to 40 C.F.R. § 60.27. This section contains no other limits or explanation for how EPA will interpret this power consistent with the CAA's limits on EPA's authority, or in a way that avoids the Agency's prior mistakes in using its error correction authority.

EPA has previously unlawfully made use of its error correction authority. For instance, in 2010 and 2011, the Agency relied on its errors correction authority to partially disapprove a Texas state implementation plan years after it had been approved on the basis that it did not regulate greenhouse gases. The case was dismissed due to lack of standing, but Judge Kavanaugh, in his dissent, reached the merits and argued persuasively that EPA had acted unlawfully.[239] This misuse of the error correction authority set out in CAA Section 110(k)(6) aptly demonstrates the problem with EPA's current proposed 40 C.F.R. § 60.27(k). Given the Agency's past use of this authority, APPA is concerned about EPA's intentions regarding its proposed error correction provision in the Section 111(d) context. With this new regulation, EPA has the opportunity to prevent previously identified problems from reoccurring and ensure that future implementation of this provision is lawful and sensible, and it should take advantage of that opportunity.

E. EPA's Revised Interpretation Regarding the Status of Modified and Reconstructed Units Is Correct.

EPA's new interpretation of the relationship between Sections 111(b) and 111(d) is correct. Previously, in the proposed Section 111(d) Rule, the Agency suggested that an existing source subject to a Section 111(d) plan would remain subject to that plan even after a

[239] *Texas v. EPA*, 726 F.3d 180, 199 (D.C. Cir. 2013).

modification or reconstruction. Although states, under Section 116, can opt to impose additional requirements on modified and reconstructed EGUs, EPA cannot require the states to regulate a unit as both a new and existing source.

The Agency reconsidered its original interpretation and published an alternative in the Proposed Trading Plan Rule.[240] EPA's revised interpretation of the CAA is correct because it is consistent with the statutory definitions in Sections 111(a)(2) and 111(a)(6). Section 111(a)(2) defines "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."[241] "Existing source" is defined in Section 111(a)(6) as "any stationary source other than a new source."[242] These terms are mutually exclusive. A source as defined by the CAA may be either a new source or an existing source, but not both. APPA acknowledges EPA's agreement regarding this matter and supports Agency's current interpretation.

XII. Conclusion

APPA respectfully submits these comments in their entirety for the Administrator's consideration. EPA should adopt APPA's recommendations in the final Trading Plan Rule. APPA's recommendations will substantially improve the Proposed Rule by providing states and affected sources with the necessary flexibility to implement the requirements of the Section 111(d) Rule in keeping with the utility industry's responsibility to provide its consumer with safe, reliable, and affordably electricity service. Thank you for your consideration of these comments on this important rulemaking. You may contact Mr. Joe Nipper

[240] 80 Fed. Reg. at 65,038-39
[241] 42 U.S.C. § 7411(a)(2)
[242] 42 U.S.C. § 7411(a)(6).

(jnipper@publicpower.org) or Ms. Carolyn Slaughter (cslaughter@publicpower.org) if there are questions regarding these comments.

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APPENDIX 1

Examples of Public Power Biomass Consumption

Lowell Light and Power is a small- to medium-sized public power utility in southwestern Michigan with approximately 2,700 electric meters. In 2008, the State of Michigan enacted the Clean, Renewable and Efficient Energy Act requiring utilities to generate 10 percent of their retail electricity sales from renewable energy resources by 2015. In 2011, after two years of study on the local potential for wind, solar, hydropower, biomass, and biogas, Lowell Light and Power released an RFP for a bio-digestion facility to be built in Lowell. Project construction began June 2014 and feedstock delivery started January 2015. The Lowell digester uses a variety of feed stocks. These include organic wastes from a local salad dressing factory, manure, and fats, oils, and greases (FOG).

In the bio-digester, a combined heat and power engine converts methane to electricity and utilizes the waste heat to maintain the temperature of the digester. The project has several tangential benefits for the city. Using organic waste in the digester cuts down on what goes into a landfill. FOG accumulate and can clog pipes and pumps both in the public sewer lines, as well as in wastewater treatment facilities. Diverting FOG from the wastewater infrastructure to anaerobic digesters prevents combined sewer overflows, which protects water quality. Partnering with local food processors (Litehouse) to reduce the cost of waste handling protects jobs and makes room for future growth. Using manure in the digester helps farmers deal with the liabilities of land-applying excess nutrients and allows for expansion in dairy operations.

The Lowell facility is the first utility scale bio-digester with this design in the United States. The facility will produce 800 kilowatts of electricity or enough energy to supply 700

homes. Power production met MISO capacity test requirements in February 2015. Continuous commercial operation of the facility began May 2015.

In Ocala, Florida, biopower and a biogenic byproduct are produced with a syngas produced by gasification of horse manure.[243] The biopower output is used to dry the manure so that it is suitable feedstock for the gasifier and the solid byproduct is used as bedding for the horses.

Manitowoc Public Utilities (MPU) owns and operates a municipal electric generating plant located in the City of Manitowoc, WI. This plant includes two existing, atmospheric pressure, circulating fluidized bed (CFB) boilers, designated as Boilers 8 and 9. Boiler 8, installed in 1990, has a maximum rated heat input capacity of 270 MMBtu per hour. Boiler 8 is permitted to fire coal, petroleum coke, fly ash, paper pellets, rubber waste derived fuels, and natural gas. Boiler 9, installed in 2004, has a nominal heat input capacity of 650 MMBtu per hour. Boiler 9 is permitted to fire coal, petroleum coke, paper pellets, and natural gas.

CFB boilers tend to be more flexible than the pulverized coal units most large Wisconsin utilities operate. However, biomass fuel must still meet certain shape requirements to be useful in boiler firing systems. In view of that, MPU prefers to use paper pellets, which are a choice fuel because they are compressed and can be easily processed into the boiler system. Interestingly, through their research with biomass fuels, Manitowoc has found corn stover to be a low Btu fuel that needs to be processed to be usable and needs to be local considering transportation costs.[244]

[243] http://issuu.com/floridahorse/docs/www.ftboa.com
[244] Conversation with Nilaksh Kothari and Tom Reed, Manitowoc Public Utilities.

Fluidized bed boilers are well adapted to burning relatively low heating value fuels, such as biomass. The renewable biomass fuels are received in a form that can be stored and handled essentially the same as the existing solid fuels used in these boilers. MPU currently processes biomass materials in the form of pellets (two sizes) and granules that are working well.

Cedar Falls Utilities (CFU) is actively researching the use of biomass fuels as an alternative to coal for a 16.5 MW generating plant. They have done a number of test burns at a stoker-fired boiler designed to burn chunks of coal. To make this type of research possible, the state Department of Natural Resources grants variances for 20 ton test burns of feedstocks not in their current permit.

Since 2004, CFU has been experimenting with various densified (cubed or pelletized) biomass products, including agricultural waste products, such as oat hulls or corn stover, and low-input, sustainable crops, such as switchgrass or multi-species prairie grass.[245] Considering their tests, CFU has encountered a few notable results. Some pellets fire unevenly, corn stover and switchgrass cubes tend to have a short shelf-life, and some are not dense enough to keep form. In addition, humidity can be a problem, and chlorine emissions may be an issue.

One of the key challenges CFU has identified beyond an optimal densification configuration for the existing stoker is the development of a biomass supply chain with a production capacity equal to or greater than the firing capacity of the boiler, which is 16 tons per hour continuously every day of the year. Behind this production capacity, a source is needed to supply the raw material needed to maintain this level of production. In terms of corn stover, this

[245] Conversation with Ed Olthoff, CFU, and http://www.cfu.net/renewable-energy/cfu-renewable-energy-initiatives.aspx.

amounts to approximately 50 square miles of corn fields, assuming two tons of raw material per acre. This would have to be harvested in a small window of opportunity in the fall after the corn is out of the fields. The ultimate challenge is the cost of the manufactured fuel, which has typically been uncompetitive with the cost of coal, and with no incentives other than the wholesale market price of electricity, biomass will not be economically viable.

The City of Redding's electric utility in California relayed two experiences. In 2006, they signed a contract with an eight MW wood biomass facility in Northern California. The project is being held up in court by an environmental group due to air quality and noise concerns. No one expected the long delay: hey had letters supporting the project from the Governor and various other elected officials. More recently, Redding began a feasibility study on a second small project at a lumber mill. The study will look at the economics of the project, cost and availability of fuel resources, and other factors. [246]

Burlington Electric Department (BED), owners of the 50 MW McNeil Generating Station in Burlington, Vermont, began burning wood chips in 1984. BED is one of the first large public power utility biomass generators. The permit contained strong forest management requirements.[247] As of 2007, about five percent of its feedstock was waste wood—shipping pallets, yard waste, and Christmas trees—supplied by local residents and businesses, 25 percent was from area manufacturers—saw mills, furniture factories, and a veneer manufacturer, and the remaining 70 percent from 30 contractors from forest residues—byproducts of the harvest for

[246] Conversation with Elizabeth Hadley, Redding Electric Utility, Redding, California.
[247] http://publicservice.vermont.gov/energy/ee_files/biomass/ee18a.htm and http://www.masslive.com/news/index.ssf/2009/10/biomass_proponents_in_western.html, Oct 17, 2009.

timber, pulp, or firewood.[248] In this case, due to a longstanding relationship with the community and strong local supplies of feedstock, the utility has minimized the significant problems associated with operating a biomass electric generation facility.

Santee Cooper, the state-owned utility in South Carolina, has found that, in general, biomass is more viable at plants less than 100 MW. Alternately, doing multiple 15 MW plants provides flexibility, spreads jobs, and provides a great for opportunity for locally available fuels production, though the plants may be higher cost.[249]

After Hurricane Hugo in 1998, Santee Cooper co-fired wood chips from fallen tree debris with coal in their boilers.[250] When the Forest Service sought applicants to thin the forest in 2004, Santee Cooper considered a long term contract to use forest thinning at its Jeffries Station in South Carolina, which would require a new handling system. They needed a lower price source of wood to cover their investment in new equipment and additional operation and maintenance costs. They were unsuccessful in their bid and their potential source chose a pulp and paper company.[251] Hence, the conclusion that large plants could take biomass from other industries; the paper industry did not like their proposed biomass plant near the Francis Marion National Forest.

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[248] Schill, Susanne Retka, "Harnessing the power of biomass," http://www.biomassmagazine.com/article.jsp?article_id=1229
[249] Conversations with Susan Jackson and Elizabeth Kress of Santee Cooper.
[250] McConnell, Lindsey, and Martha C. Monroe, University of Illinois Extension, March 12, 2010, http://www.extension.org/pages/Challenges_of_Obtaining_a_Wood_Supply
[251] McConnell.

Wyandotte Municipal Services (WMS) received a state grant to demonstrate the feasibility of co-firing biomass fuel. They chose boiler #8, a 25 MW circulating fluidized bed boiler capable of firing coal, untreated virgin wood chip waste, and tire-derived fuel. All Michigan utilities are required to meet a 10 percent renewable energy standard by 2015. The Wyandotte project "investigated the logistics of acquiring and handling various woody biomass fuels and conducted a test burn of the proposed fuel to identify any technical challenges and develop recommendations for future use. Today, WMS relies on two coal-fired boilers and sources roughly 85 percent of its power from coal. WMS is striving to diversify its generation portfolio and use of renewable energy and energy efficiency."[252] Given their timeframe, they found one supplier in the state.

Testing concluded that the densified wood cubes traveled well through the existing conveying system. Dust was an issue during the loading process, but for the purpose of the test burn, good general housekeeping was maintained to mitigate this issue. During testing, the boiler reacted well to the introduction of biomass and was capable of providing a steady 160,000 lb/hr of steam flow while burning 15 percent and 30 percent biomass by heat input.[253]

The unique aspect of Wyandotte's pilot was using up to 30 percent of heat input from biomass, in this case pellets from renewaFUEL;[254] 5-10 percent is the norm. The remaining heat input was their usual mix of 60/40 coal/tire. They experienced degradation of pellets in the pilot, advising the least handling of biomass possible to keep costs down. Whether they use biomass in the future will depend on the price of RECs.

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[252] Wyandotte Municipal Services, "Advancing Renewable Energy: Displacing Coal with Woody Biomass in Wyandotte Municipal Services #8 Boiler," draft report, July 15, 2010, p. iv and 1.
[253] Wyandotte, p. iv.
[254] RenewaFUEL, http://www.cliffsnaturalresources.com/Renewafuel/Profile/Pages/Home.aspx.

APPENDIX 2

Compliance Scenarios under the EPA Clean Power Plan

December 23, 2015

Prepared by Energy Strategies, LLC, for the
American Public Power Association

energy strategies

American Public Power Association
SEVENTY-FIVE YEARS

Disclaimer and Acknowledgement

Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, UT 84111
(801) 355-4365

American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202
(202) 467-2900

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1.0 INTRODUCTION

The American Public Power Association (APPA) is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the U.S. Collectively these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA members comprise utilities that own and operate a rich and diverse fleet of electric generating sources which will soon have to meet recently finalized carbon dioxide (CO_2) emission goals set forth under section 111(d) of the Clean Air Act. APPA commissioned this study from Energy Strategies to review the various CO_2 emissions trading schemes and their respective impact to public power utilities in the context of the final Clean Power Plan rule and proposed federal plan and model trading rules.

1.1 CLEAN POWER PLAN BACKGROUND

EPA released the final rule regulating CO_2 as a pollutant from existing power plant sources on August 3, 2015. The rule was promulgated under section 111(d) of the Clean Air Act and is known as the Clean Power Plan (CPP). Nationally, EPA predicts the state emission goals will result in 32% lower CO_2 emissions than the 2005 baseline by 2030.

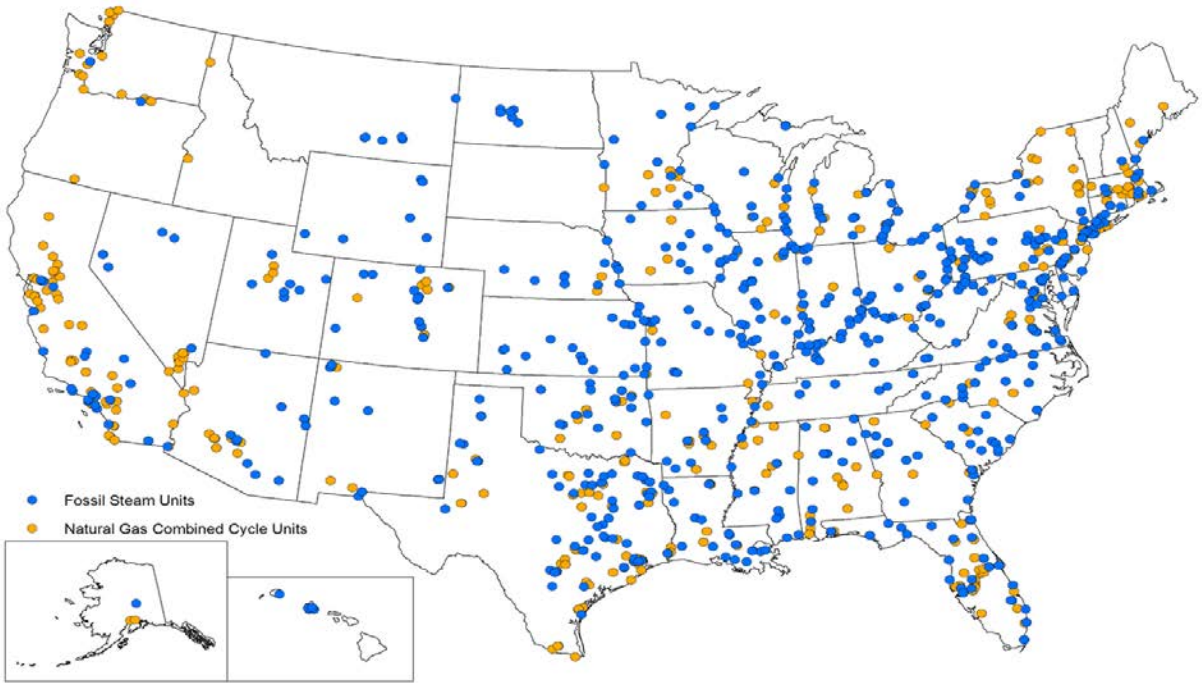
The CPP sets nationwide subcategory-specific CO_2 emission performance rates for fossil-fueled steam electric generating units and stationary combustion turbines. Together, these two types of power plants are known in the CPP as affected electric generating units (EGUs). The emission performance rates, in pounds of CO_2 per megawatt-hour (lbs CO_2/MWh) are:

- 771 lbs CO_2/MWh for stationary combustion turbines, e.g., natural gas-fired combined cycle (NGCC) units, and

- 1,305 lbs CO_2/MWh for fossil-fueled (coal, oil/gas) steam electric generating units.

The locations of the CPP affected EGUs are shown in Figure 1.

FIGURE 1: CPP AFFECTED EGUS



Source: EPA

In addition to the national performance standards for existing coal- and certain natural gas-fired power plants, the rule also established a goal for each state. While the national performance standards are expressed in terms of intensity, or a rate (pounds of CO_2 per MWh), states also have the ability to develop their compliance plans around a "capped" amount of total emissions (in annual short tons of CO_2 emissions). The two different approaches are known as rate based or mass based.

The EPA calculated the rate-based state goals by applying the national performance standards to each state's resource mix for affected EGUs. So

for those states with only natural gas-fired generation, the state goal is the same as the NGCC emissions performance rate (771 lbs CO_2/MWh). For states with only coal-fired plants, the state goal is the same as the coal-fired performance rate (1,305 lbs CO_2/MWh). Most states, of course, fall somewhere in between. Table 1 lists the statewide rates required for the final period (2030 and beyond).

TABLE 1: CLEAN POWER PLAN FINAL PERIOD STATEWIDE RATE GOALS

State	Statewide Rate Final Goal, in lbs CO_2 per Net MWh	State	Statewide Rate Final Goal, in lbs CO_2 per Net MWh
Alabama	1,018	Missouri	1,272
Arizona*	1,031	Montana	1,305
Arkansas	1,130	Nebraska	1,296
California	828	Nevada	855
Colorado	1,174	New Hampshire	858
Connecticut	786	New Jersey	812
Delaware	916	New Mexico*	1,146
Florida	919	New York	918
Georgia	1,049	North Carolina	1,136
Idaho	771	North Dakota	1,305
Illinois	1,245	Ohio	1,190
Indiana	1,242	Oklahoma	1,068
Iowa	1,283	Oregon	871
Kansas	1,293	Pennsylvania	1,095
Kentucky	1,286	Rhode Island	771
Fort Mojave Tribe	771	South Carolina	1,156
Navajo Nation	1,305	South Dakota	1,167
Uintah and Ouray	1,305	Tennessee	1,211
Louisiana	1,121	Texas	1,042
Maine	779	Utah*	1,179
Maryland	1,287	Virginia	934
Massachusetts	824	Washington	983
Michigan	1,169	West Virginia	1,305
Minnesota	1,213	Wisconsin	1,176
Mississippi	945	Wyoming	1,299

** Excludes EGUs located in Indian country within the state.*

The EPA developed the mass-based state goals by first taking the state's rate goal and multiplying it by the 2012 affected EGU hours of generation, then applying an adjustment to account for the potential for additional renewable energy (which raised the emissions cap). Table 2 lists the mass-based goals for the states for the final period (2030 and beyond).

TABLE 2: CLEAN POWER PLAN FINAL PERIOD MASS-BASED ALLOWANCE GOALS

State	Mass-Based Goal, in Short Tons CO_2	State	Mass-Based Goal, in Short Tons CO_2
Alabama	56,880,474	Missouri	55,462,884
Arizona*	30,170,750	Montana	11,303,107
Arkansas	30,322,632	Nebraska	18,272,739
California	48,410,120	Nevada	13,523,584
Colorado	29,900,397	New Hampshire	3,997,579
Connecticut	6,941,523	New Jersey	16,599,745
Delaware	4,711,825	New Mexico*	12,412,602
Florida	105,094,704	New York	31,257,429
Georgia	46,346,846	North Carolina	51,266,234
Idaho	1,492,856	North Dakota	20,883,232
Illinois	66,477,157	Ohio	73,769,803
Indiana	76,113,835	Oklahoma	40,488,199
Iowa	25,018,136	Oregon	8,118,654
Kansas	21,990,826	Pennsylvania	89,822,308
Kentucky	63,126,121	Rhode Island	3,522,225
Fort Mojave Tribe	588,519	South Carolina	25,998,968
Navajo Nation	21,700,587	South Dakota	3,539,481
Uintah and Ouray	2,263,431	Tennessee	28,348,396
Louisiana	35,427,023	Texas	189,588,842
Maine	2,073,942	Utah*	23,778,193
Maryland	14,347,628	Virginia	27,433,111
Massachusetts	12,104,747	Washington	10,739,172
Michigan	47,544,064	West Virginia	51,325,342
Minnesota	22,678,368	Wisconsin	27,986,988
Mississippi	25,304,337	Wyoming	31,634,412

** Excludes EGUs located in Indian country within the state.*

EPA's adjustment for the renewable energy potential is not large: the implied electric generation from these sources in the 2030 mass-based goals is only

112% of the 2012 electric generation. (This is effectively a 0.6% compound annual growth rate.) Without this adjustment, a mass-based goal would be automatically more stringent than a rate-based goal, because the rate-based goal allows for unlimited growth in electricity demand ("load growth") to be served by these existing EGUs without violating the standard. EPA also supplies a second mass-based goal within the rule for states wishing to include new resources ("new source complement") built after 2012.

The first interim goal period under the final rule begins in 2022. There are three interim goal periods, based on multi-year steps: 2022–2024, 2025–2027, and 2028–2029. The final goal must be achieved in every two-year compliance period beginning in 2030.

1.2 Summary of Compliance Options

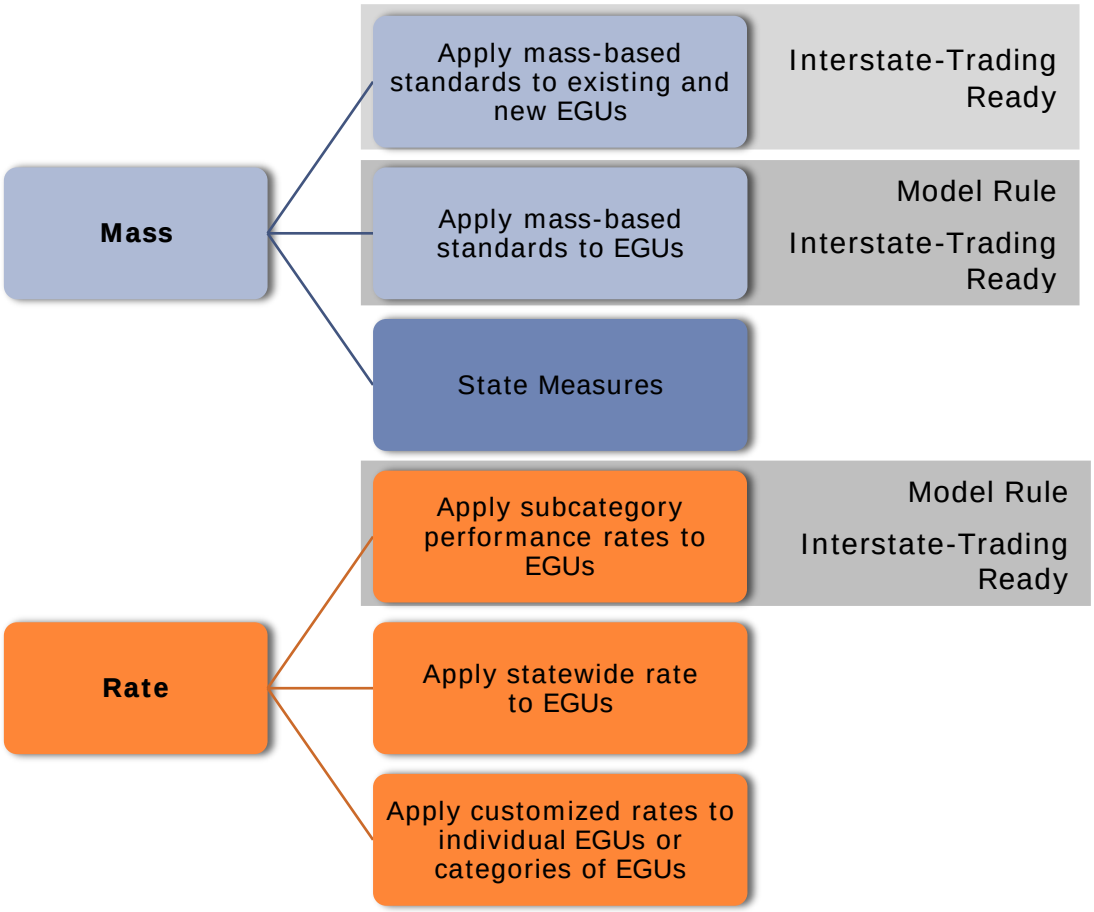
States have considerable flexibility in developing a plan to meet the standard. States will need to submit an initial plan to the EPA no later than September 2016, and a final plan no later than September 2018. If a state chooses to not submit a state plan, or if EPA does not approve the plan it submits, then a federal plan would be imposed and the state would be required to achieve the compliance requirements of the federal plan. There are essentially six pathways for states to follow in developing a state plan. Five of the plan types are "Emission Standards" plans, which would establish emission standards for a state's affected EGUs—either using a rate-based goal or a mass-based goal. The sixth pathway is a "State Measures" approach, which is only available as a mass-based plan.

States will have to consider many factors in determining which type of state plan they will file. These include: state policy goals, the need for interstate

trading, ease of compliance, ease of plan preparation, cost of compliance, and the likelihood of acceptance by EPA, among many other factors.

In Figure 2, the potential state plan pathways are illustrated. Two pathways in the figure are identified as "model rules." With the release of the final CPP, EPA also released two draft federal plans, which also (with some differences) serve as model plans that states can use as a template in developing their own plans along these pathways. EPA identifies three of the pathways as "Interstate-Trading Ready."

FIGURE 2: SIX PATHWAYS FOR STATE PLANS



There is no requirement for multi-state agreements to enable trading under these interstate-trading ready plans. The only requirement under these pathways for interstate trading is that the state elects trading (accepting

compliance instruments issued in other states for compliance by EGUs in their state, and allowing compliance instruments they issue to be used in others states), has an approved plan, and uses an EPA-administered or EPA-approved trading platform. In the draft federal plans, EPA stated it would set up and administer trading platforms for both mass- and rate-based compliance instruments. This platform will be available to states that file these trading-ready plans, as well as to states using the federal plans.

Interstate trading is possible with two of the other plans, but the state plan filing would be more onerous. For example, with the rate-based plan that uses the statewide rate goal, trading is possible but requires the filing of a multi-state plan, in which two (or more) states blend their rates (creating a new weighted-average rate based on resource mix). Thus, states would need to coordinate with other state(s) and develop a multi-state trading agreement in advance of submitting a final CPP state plan in September 2018. Interstate trading under this plan type would also be limited to states in the multi-state plan, reducing the size of the potential trading market. The other example would be states choosing the State Measures plan. These states can also elect for and design their plans to be interstate-trading ready, but there would be many hurdles for EPA approvability. Interstate trading would not be allowed if a state chooses a rate-based Emissions Standards plan with customized rates for individual or categories of its affected EGUs. *Intra*state trading is available with all the plan types.

As noted earlier, the EPA released two draft federal plans, one rate-based and one mass-based, with the final rule. Only one will be finalized as the default federal plan for states that do not file (or do not receive approval of) a state plan. Both federal plans include interstate trading.

EPA is expecting compliance primarily through the trading of compliance instruments among states, because EPA believes there will be “headroom”

for EGUs to over-comply and monetize the over-compliance through trading. States, not EPA, must authorize trading, and so trading is not required in state plans. There are references in the rule to some awkward alternatives such as bi-lateral transactions or a state giving flexibility to an owner of multiple affected EGUs, but the assumption made by EPA and the assumption made for this briefing paper is that “many, if not all” states will authorize a form of trading. This assumption is reasonable because the industry is very interconnected and familiar with trading, and the economic benefits of trading are well understood. It is critical to note that multi-state trading agreements (as with the Regional Greenhouse Gas Initiative or RGGI) are not required for interstate trading to occur. Many states will choose to file a trading-ready plan and allow the EPA to administer and track the compliance instruments, as it does with the EPA-administered SO_2/NO_X programs. All utilities and their respective state environmental regulators are already very familiar with this style of program.

States that trade compliance instruments under the CPP do not have to be adjacent or neighboring. No physical delivery of electricity to the market participant who purchases or sells the compliance instruments is required. While this enlarges the market substantially, it does potentially create challenges for utilities that serve retail load located in one state from an EGU located in a different state. These trading and compliance options are explored at length in the remainder of this briefing.

For a rate-based program, the compliance instrument would be Emission Rate Credits (ERCs), a new term developed by the EPA for the CPP. For mass-based programs, the compliance instrument would be emission allowances. Under the final rule there would be no translation between ERCs and allowances: mass-based states could only trade with other mass-based states, and rate-based states would only be able to trade with other rate-based states.

1.2.1 Rate-Based Plan Trading: Emission Reduction Credits

ERCs are tradable compliance instruments and represent a zero emission MWH. Affected EGUs would obtain ERCs to achieve compliance with the CPP. Under a rate-based state plan, EGU compliance cannot be achieved by reducing generation alone (unless a unit is shut down, in which case the rate becomes zero), although reducing generation will reduce the number of ERCs that need to be acquired.

ERCs may be created in a variety of ways, such as generating energy from new renewable energy resources, implementing energy efficiency measures, or generating new nuclear energy. Each state (or the EPA, under the federal plan) would determine the requirements for ERC creation. The draft rate-based federal plan does not allow for ERC creation through energy efficiency measures.

ERCs can also be created by generating energy from NGCC units. Since ERCs technically represent a zero-emission MWh, there is a complicated formula in the federal plan/model rule to calculate the number of ERCs created by running NGCC units. States may develop different calculations, subject to approval by the EPA. Under the federal plan/model rule, existing NGCCs earn a fraction of an ERC for every MWh they run. While this theoretically represents the re-dispatch of coal units to existing NGCC units, there is no historical basis or capacity factor requirement for existing NGCC units to begin creating these “re-dispatch” ERCs. In a state using subcategorized rates, or under a rate-based federal plan, existing NGCCs will *create* ERCs (referred to as Gas Shift or GS-ERCs in the federal plan) but these units will also *need* ERCs to comply given the typical NGCC emission rate. There is no “netting” of ERCs for NGCC compliance in the federal plan; an NGCC unit

cannot net the difference between the number of ERCs it needed (to be under the emissions performance standard) against the number of ERCs it created through "re-dispatch" or GS-ERCs. In the federal plan, GS-ERCs can only be used by coal EGUs; NGCC EGUs cannot use their own GS-ERCs or those created by other NGCCs to comply.

For a coal plant operating at the national average of 2,249 lbs CO_2/MWh, for every MWh of energy generated, it would need to acquire about 0.72 ERCs to bring its average down to 1,305 lbs CO_2/MWh. (The ERCs are added to the denominator to reduce the rate: 2,249 ÷ (1 + 0.723) = 1,305.) For an NGCC plant operating at the national average of 908 lbs CO_2/MWh, for every MWh of energy generated, the plant would create about 0.08 GS-ERCs (as defined in the federal plan) and need about .18 ERCs to comply with a standard of 771 lbs CO_2/MWh.

Under mass-based plans, EPA is concerned about "leakage" whereby compliance is achieved through a shift in generation from existing units to new units instead of applying the best system of emission reduction (BSER) to existing units. There is no corresponding concern in rate-based plans. New NGCC EGUs will not create ERCs and therefore are not incentivized to run to replace existing affected EGUs in a trading scheme. Therefore, EPA does not require states to address leakage to new EGUs in rate-based plans.

1.2.2 Mass-Based Plan Trading: Allowances

Allowances are authorizations to emit one short ton of CO_2 during the compliance period. In a mass-based system, compliance can be achieved by simply generating less (as fewer emission are created as a result), or it can be achieved by obtaining allowances from others that generated less, or not at all, and therefore had excess allowances. Compliance can also be

achieved by purchasing allowances owned by other entities (e.g., a state may allocate allowances to renewable energy projects).

As with other mass-based trading programs, in order to comply, the covered EGUs would periodically surrender allowances equal to its emissions. EGUs would obtain some initial quantity of allowances through an allocation or auction process. This distribution process is often the most controversial aspect of a cap-and-trade program. EPA has indicated that states have complete flexibility in their method of allowance distribution.

While states have this flexibility, it is worth looking closer at the distribution method in the proposed federal plan, as that forms the basis of some modeling iterations. Recall that each state's mass-based "cap" or total number of allowances by compliance period, as set in the Clean Power Plan, is based on a calculation that first multiplies the statewide rate by 2012 affected EGU hours of generation, then adds additional allowances to account for the renewable energy opportunity (see 1.1, and each state's final compliance period annual total allowances in Table 2). The choice of distribution method does not affect this cap, and states may choose any metric for the distribution of allowances up to this cap (ignoring, for example, the 2012 generation metric that EPA used to calculate the cap). EPA's allowance allocation method in the proposed federal plan would allocate most of the allowances to affected EGUs based on their average 2010–2012 historical generation, with the remaining allowances held in three "set-asides." Both these concepts, the set-asides and the metric used to allocate allowances to affected EGUs, have an impact on the compliance gap for any particular EGU, as will be seen in the modeling iterations analyzed later in this paper. Set-asides effectively reduce the overall bucket of allowances, removing a certain amount of allowances that would otherwise be allocated to the EGUs, often to achieve a policy goal. The metric used to distribute the remaining allowances in the proposed federal

plan is a three-year average of historical generation. After the set-asides, the federal plan would distribute the remaining allowances to EGUs on a pro rata basis based on their share of the state's 2010–2012 generation from affected EGUs.

The three set-asides in the federal plan are for the Clean Energy Incentive Plan (CEIP), a separate renewable energy development incentive program, and a rolling adjustment fund for updated NGCC generation. The first set-aside was designed to incentivize early action in developing renewable energy and low-income energy efficiency projects. EPA included the other two set-asides in part to address leakage to new NGCCs, that is, EPA believes this allocation methodology avoids creating an unintended incentive for new CO_2-emitting EGUs to run more. Under a mass-based system, existing NGCC units have an additional variable cost (the need to purchase allowances) that a new NGCC unit does not. By providing these units with allowances at no cost, based on historical generation, and including these set-asides, the additional variable cost for existing NGCC units is close to zero.

EPA is taking comment on using a historical emissions approach, as opposed to the historical three-year average generation approach proposed in the draft federal rule, and other potential variations in the allocation method under the federal plan.

It should be noted that the set-asides under the federal plan/model rule are substantial, and vary by state. The proposed renewable energy set-aside is a straight 5% and affects every interim period year and final goal year. The CEIP set-aside only affects the three years of the first interim period, but it ranges from less than 1% to nearly 10% of a state’s first interim goal, as it is based on each state’s final goal as a percent reduction from 2012 emissions. (California has the lowest set-aside, and Montana the highest.)

The output-based adjustment does not affect the first interim period, but would affect all subsequent periods. It varies based on the state's existing NGCC capacity, and ranges from zero (e.g., Montana, Navajo Nation) to more than 27% (e.g., Maine) as a percent of the state's final goal. The effect of the proposed output-based set-aside in the federal plan/model rule will be to reduce the pool of allowances within a state for coal-fired units and low-capacity-factor NGCCs, redistributing the allowances to existing NGCC units that operated above a 50% capacity factor in the prior compliance period.

As noted earlier, EPA has indicated each state has many options to create its own allocation process. This flexibility is provided even if the state's EGUs are regulated under a federal plan, as EPA will allow the submission of a partial plan that only addresses the allocation process. For all allocation methods, the EPA indicates the plan must address leakage to new NGCC units. States may still choose to allocate allowances using historical generation data, but not use a three-year average. States may instead use historical emissions data, which would benefit those EGUs that have historically been the largest emitters. States may also use historical heat input data, which would benefit those EGUs that historically have used the most fuel. Heat input, usually expressed in million British thermal units or MMBtu of fuel per hour, is a measure that accounts for the heating value of the fuel (in MMBtu per pound of fuel) and the feed rate of the fuel into the EGU to generate electricity (in pounds of fuel per unit of time). States may also use projected rather than historical data, choosing projected generation, heat input, or emissions. As in the federal plan, there may be different allocation methods depending on the period, with an "updating" feature. States may also allocate allowances to load-serving entities (i.e., distribution utilities) instead of affected EGUs. EPA also indicates states have the option to auction, rather than allocate allowances. In an auction, the allowances would go to those entities willing to pay the highest price for the allowances;

states could design auctions with or without price “floors” or “ceilings,” and with or without set-asides. Auction revenue could be used by states to fund programs, such as energy efficiency programs, or could be used to offset customer rate impacts, through a rebate scheme.

2.0 Scenarios and Methodology

This project is centered on the analysis of two specific scenarios, as requested by APPA. For both scenarios, trading and compliance options are considered under several different rate- and mass-based state compliance pathways, with a specific focus on the potential impacts of the two proposed federal plan options. However, the scenarios as discussed below are presented in a generic manner to help make the report useful to a wider audience of APPA members. The two scenarios and the overall methodology are described below.

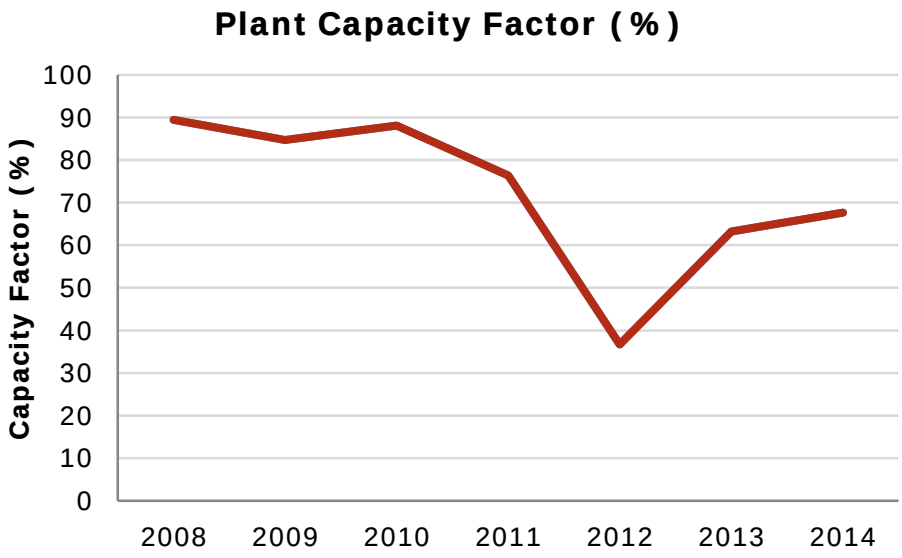
2.1 Scenario 1: Single Coal-Fired EGU

This scenario is focused on a Texas-based joint-action agency that owns one coal-fired generator that is used to serve load for several municipalities. The purpose of this scenario is to understand how a “coal-only” utility might fare under various state compliance plans, given that it owns a single EGU, lacks access to other resources (including renewables), and is the sole provider of electricity to its municipal customers.

The CPP compliance period starts in 2022 and continues through 2030, at which point EGUs must meet the final 2030 target and maintain the performance standard for each successive two-year compliance period. The most important assumptions required for assessing an EGU’s need for

allowances or ERCs during the compliance period is the EGU's forecasted generation and corresponding forecasted emissions. Since the scenarios are based on actual generators, we assumed that future generation would be in line with recent historical data, which is shown below in Figure 3 for the EGU in Scenario 1.

FIGURE 3: SCENARIO 1 EGU HISTORICAL GENERATION



The key assumptions used to calculate the future emissions from the EGU in Scenario 1 are outlined below in Table 3.

TABLE 3: SCENARIO 1 EGU SUMMARY

State	Texas
Capacity	453 MW
Fuel	Coal (subbituminous)
Emission rate (2012 – EPA)	2,320 lbs/MWh
Forecasted capacity factor	75%

Since the joint-action agency that owns the EGU in Scenario 1 does not have retail load and sells the plant's output to municipalities, the utility does not stand to gain any ERCs created from energy efficiency programs (without procuring them from others). The utility does not own any post-2012 renewable energy resources, and does not plan to construct or procure any in the near term, due to flat demand for electricity. Thus, the compliance scenarios analyzed assumes that the expected future (or base case) is one where the EGU must procure all required ERCs or allowances.

2.2 Scenario 2: Cross-State Load and EGU

In this scenario, we focus on a mixed-resource multi-state joint action agency that owns a share of an EGU located in one state and serves load, on a wholesale basis (to municipalities), in multiple states, none of them being the state where the EGU is located. This utility plans to construct some post-2012 renewable energy resources, but these resources are also not in the state where the affected EGU is located. While this utility provides only wholesale power to its customers, in this scenario we assume that those customers pass along any ERCs gained from energy efficiency programs to the utility.

The purpose of this scenario is to investigate how a mixed-resource utility would fare under various state compliance plans given that they own a single EGUs but have contracted or owned renewable energy resources in neighboring states. Unique to Scenario 2 is the interaction between neighboring state plan options. If the utility wishes to capture ERCs or allowance allocations from out-of-state renewable energy resources or energy efficiency programs to help with an in-state EGU's compliance, both states must allow interstate trading and both states must be operating under

a mass-based plan, or both states must be operating under a rate-based plan. (The only exception to this prohibition would be a renewable energy project developed in 2013 or later, operating in a mass-based state, not receiving allowances from its home state, and operating under a PPA to serve load in a rate-based state that offers ERC creation for renewable energy projects that serve load in that state.)

As in Scenario 1, we used historical generation to forecast future operations of the EGU. This information, along with other key assumptions used to calculate future emissions from the EGU, is outlined below in Figure 4 and Table 4, respectively.

FIGURE 4: SCENARIO 2 EGU HISTORICAL GENERATION

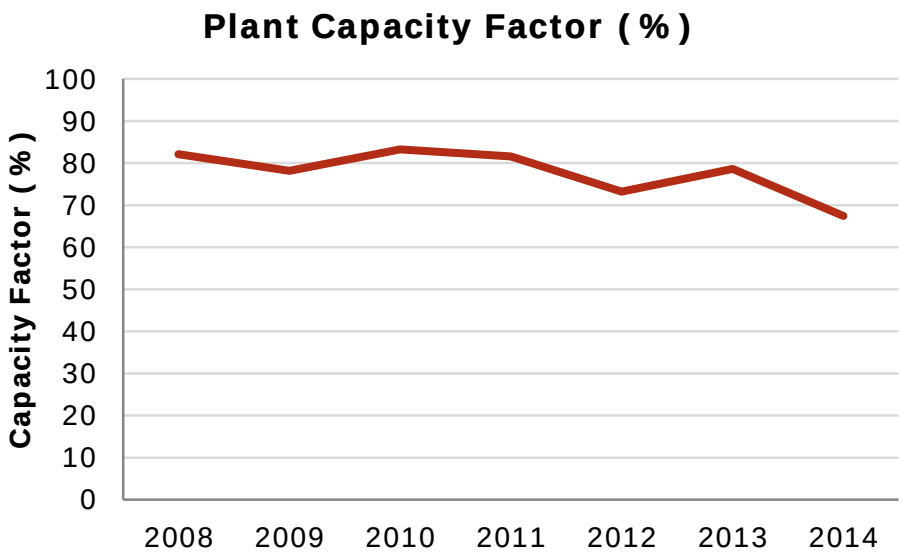


TABLE 4: SCENARIO 2 EGU SUMMARY

State	Wyoming
Capacity (owned)	282 MW
Fuel	Coal (subbituminous)
Emission rate (2012 – EPA)	2,430 lbs/MWh
Forecasted capacity factor	75%

The utility in Scenario 2 has a series of "expected actions" that are assumed to assist with EGU compliance whenever allowed by combinations of state plans. These compliance measures are summarized in Table 5, below. We assumed that a small 5 MW wind facility enters service in 2015, an incremental 32 MW hydro facility starts operation in 2018, and that an energy efficiency program saves more than 500,000 MWh between 2013 and 2030 (i.e. incremental savings from 2012). It was assumed that the utility does not have any other EGUs and that all credits from these compliance measures could be counted toward the Wyoming EGU's compliance (again, when the state-to-state trading mechanisms allowed for it).

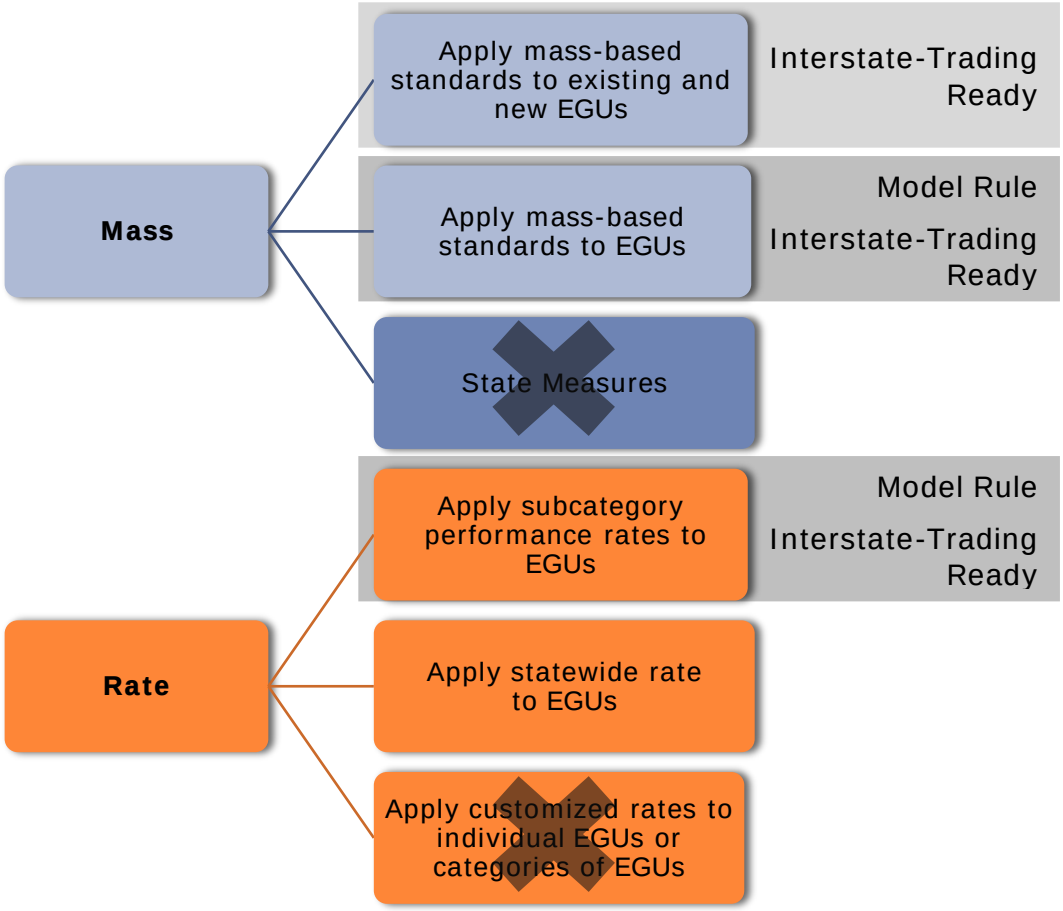
TABLE 5: SCENARIO 2 PLANNED COMPLIANCE MEASURES

New Renewable Energy (Wind)	
Location	Different state than EGU
Capacity	5 MW
In-service date	2015
Annual energy (MWh)	15,330 MWh (35% capacity factor)
New Renewable Energy (Hydro)	
Location	Different state than EGU
Capacity	32 MW
In-service date	2018
Annual energy (MWh)	178,000 MWh (63% capacity factor)
New Energy Efficiency	
Location	Different state than EGU
Capacity	NA
In-service date	Post-2012 (2013–2030)
Total energy (MWh)	555,169 MWh

2.3 Analytical Approach Used For the Scenarios

The analysis in the following section estimates the compliance gap (number of compliance instruments that will be needed for the affected EGU) and provides discussion around the potential compliance options available, including interstate or intrastate trading. For simplifying purposes, this analysis eliminates the State Measures pathway from consideration as well as a rate-based pathway that does not allow for any interstate trading, as seen in Figure 5. At this time, the remaining four pathways are those being considered by most states.

FIGURE 5: FOUR OF THE SIX PATHWAYS ARE USED IN THIS ANALYSIS



2.3.1 COMPLIANCE GAP

The compliance gap, which quantifies the number of ERCs or allowances the EGU would need to maintain forecasted operations during the compliance period, is calculated for each of the two scenarios under the four different types of plans listed in Table 6.

TABLE 6: COMPLIANCE GAP CALCULATION

	Scenario 1	***Scenario 2***
Mass	Apply mass-based standards to existing and new EGUs	Apply mass-based standards to existing and new EGUs
	Apply mass-based standards to EGUs	Apply mass-based standards to EGUs
Rate	Apply subcategory performance rates to EGUs	Apply subcategory performance rates to EGUs
	Apply statewide rate to EGUs	Apply statewide rate to EGUs

Ultimately, there were 22 models built to calculate compliance gaps, because within the two scenarios and four pathways, there were a number of permutations. For example, for Scenario 2, the compliance gap for the "apply subcategory performance rates" pathway would differ depending on whether the state followed the federal plan (which does not allow for energy efficiency) or developed its own state plan that included energy efficiency. There were more modeling runs for the mass-based pathways than the rate-based ones, primarily to study the impact of various allowance allocation methodologies. As noted earlier, EPA is allowing the states significant flexibility in allocating allowances, with the potential for set-asides, auctions,

and distributions based on a variety of metrics (historical or projected generation, emissions, or heat input). Depending on the methodology for distribution, and EGU could receive more or fewer allowances from a state, thus increasing or decreasing its compliance burden. As mentioned previously, this issue is one of the most contentious for mass-based trading programs and receives considerable attention later in this report.

In addition to the plan types listed above, we investigated the impact that state coordination would have in Scenario 2. This analysis involved calculating the compliance gap the EGU in Scenario 2 would face if the planned compliance measures listed in Table 5 were or were not available, as determined by the combination of state plans adopted by the EGU-state and the state where the compliance measures were located. For simplifying purposes, we assumed an “all or nothing” approach, meaning that the compliance measures in Scenario 2 were not parsed out into specific states and every combination of those state’s potential plans were not studied.

2.3.2 Compliance Measures

The compliance gap analysis is useful as it depicts the “burden” the EGU may face during the compliance period. However, it is difficult to translate the need for ERCs or allowances into more tangible values. Since an evaluation of the cost of compliance for each EGU was outside the scope for this project, we pursued alternative approaches to quantifying the compliance gap. Note that for Scenario 2 the quantification of this compliance gap was intended to capture the compliance burden above and beyond the planned/expected compliance measures.

Depending on whether the gap was quantified in ERCs or allowances, we employed different metrics to demonstrate potential actions the utility would need to take to “close” the compliance gap for the EGU. In the case of ERCs,

we calculated the amount (e.g., capacity in MW) of renewable energy that would have to be built or contracted during the compliance period. It was assumed that these resources would create ERCs (that would be used toward compliance) and that they would be located in a state with an interstate-trading ready rate-based plan. We quantified compliance gaps in mass-based scenarios by estimating the reduction in generation (e.g., the capacity factor that the EGU would have to re-dispatch down to) in order to achieve compliance. For this metric, we did not assume any replacement generation.

We did not combine compliance measures to estimate or quantify the compliance gap; each example provided closes the gap but may not be realistically achievable. That is, we did not create a realistic compliance "portfolio" that included some amount of reduction in generation with new renewable energy development, for example. This incremental step was outside the scope of this work for this project, which was focused on identifying how the magnitude of the compliance gaps differ across varying plans.

3.0 Analysis

3.1 Scenario 1: Single Coal-Fired EGU

For many reasons, mass-based and rate-based plans are extremely different. With few exceptions, mass states will only be able to trade with other mass states, and rate with rate. The compliance instruments are very different, with allowances coming into being the moment a state chooses a mass-based pathway, and ERCs only becoming available as entities do something—build a renewable energy project, run NGCCs more, implement

an energy efficiency project. This report therefore discusses rate and mass in separate sections, with an analysis that attempts to discuss the different merits of the two pathways in a summary section (rate or mass will be one of the most key decisions a state will make). Since there were fewer models built to show the rate-based pathways, we begin with rate.

3.1.1 Compliance Gaps (And Implications) Under a Rate-Based Pathway

Scenario **1**
Rate

To investigate the compliance gap and the implications under various rate-based pathways for the Scenario 1 EGU, we conducted three modeling iterations. We looked at the EGU under a statewide rate versus the subcategorized rates, and within the subcategorized rates pathway, we looked at both the federal plan and the model state plan. Below, we draw on the findings from this analysis to answer critical questions for the Scenario 1 EGU.

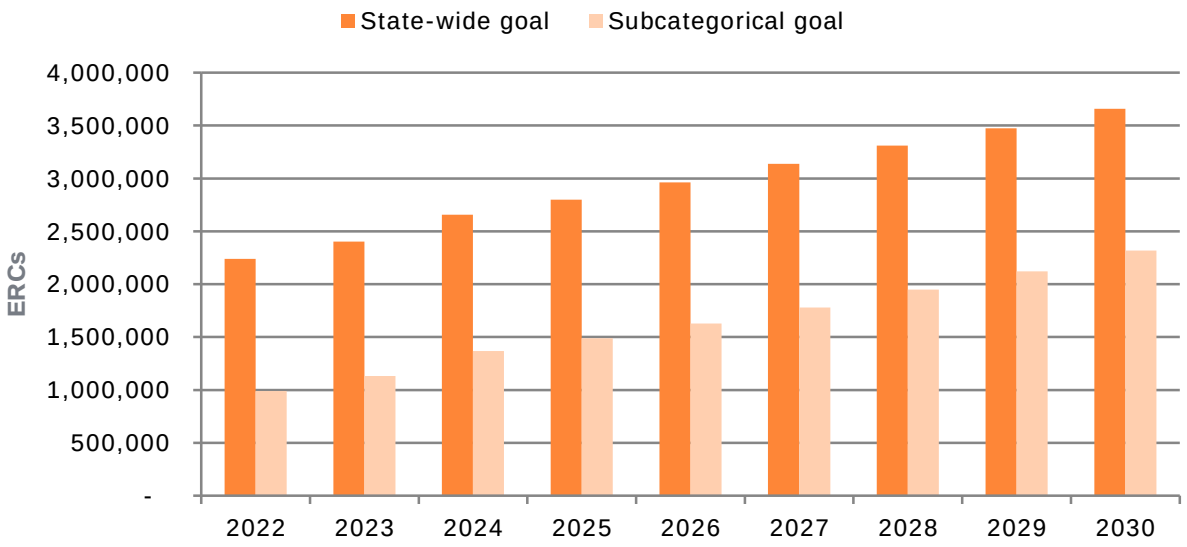
- *How does the use of the statewide goal versus the subcategorized goals impact the EGU's compliance deficit?*

Within the rate-based approach, the first major division is those states that might choose a statewide rate rather than subcategorized rates. As noted earlier, using subcategorized rates eliminates the need to create a multi-state plan for interstate trading. Using subcategorized performance rates (loosely, one for coal, one for NGCC) rather than the "blended" statewide rate allows a state to create an interstate-trading ready plan much more quickly and easily.

Because the EGU in Scenario 1 is a coal-fired unit, the ERC deficit is much higher in the statewide rate models than in the subcategorized rate models.

In this particular state (Texas), the EGU benefits from the 1,305 lbs CO_2/MWh subcategorized rate, versus this state's 1,042 lbs CO_2/MWh statewide rate. Figure 6 below illustrates the annual ERC requirement by year, with the statewide rate requirement much higher than the subcategorized requirement.

FIGURE 6: ANNUAL ERC REQUIREMENT FOR SCENARIO 1



- *How does the proposed rate-based federal plan impact the EGU?*

Both a subcategorized rate federal plan and a subcategorized rate model state plan were investigated as a part of this study. In terms of the compliance gap faced by the EGU in Scenario 1, both subcategorized rate-based plans were identical. This is because the key difference between the rate-based federal plan and potential rate-based state plans is that energy efficiency does not create ERCs in the proposed federal plan, and Scenario 1 has no direct energy efficiency opportunity.

It should be noted that if energy efficiency is not available in some or many plans, that would reduce the pool of ERCs available to purchase in interstate trading markets. If energy efficiency were not available as an ERC-creating

measure, most ERCs would be created through the re-dispatch of NGCCs and through new renewable energy projects. This could increase the cost of compliance. Since the utility in Scenario 1 does not serve retail load and it will not have direct access to energy efficiency-driven ERCs, the compliance gaps were consistent between the federal and state rate-based plans.

- *How many cumulative ERCs are needed in 2030 based on the models for Scenario 1?*

Based on assumptions described earlier in this report, we can calculate the annual ERC requirement for the EGU as being the number of ERCs that would be required to bring that EGU's effective emission rate into compliance with the scenario's particular rate-based target. The 2030 cumulative ERC requirement would be the sum of each annual requirement over the compliance period (2022–2030). The cumulative ERC requirements for Scenario 1 are provided in Table 7, below.

TABLE 7: CUMULATIVE ERC REQUIREMENTS IN 2030 FOR SCENARIO 1

Plan Type	Performance Standard	Cumulative ERC Requirements
Federal Plan	Subcategorized Performance Rates	14,776,848
State Plan	Subcategorized Performance Rates	14,776,848
	Statewide Rate	26,641,022

- *How could that many ERCs be created?*

Both the proposed federal as well as the state model rules allow EGUs to reduce their "effective" emission rate by procuring ERCs from renewable generators installed after 2012. For Scenario 1, assuming the EGU were to operate as outlined in the assumptions above, the utility would have to

either procure or generate between roughly 14 million and 27 million ERCs from renewable energy or energy efficiency projects, depending on whether the state adopted a plan using subcategory rates or statewide rates.

To demonstrate how much renewable energy infrastructure would be required to produce this level of ERCs, we calculated the amount of renewable energy capacity (in MW) that would have to be built or procured during each year of the compliance period. It was assumed the renewable energy installed in year 2022 would generate ERCs in that year, and every year in the compliance period thereafter (and some time beyond 2030). The *cumulative* amount of renewable energy capacity required to achieve 2030 compliance under each rate-based plan type is summarized in Table 8.

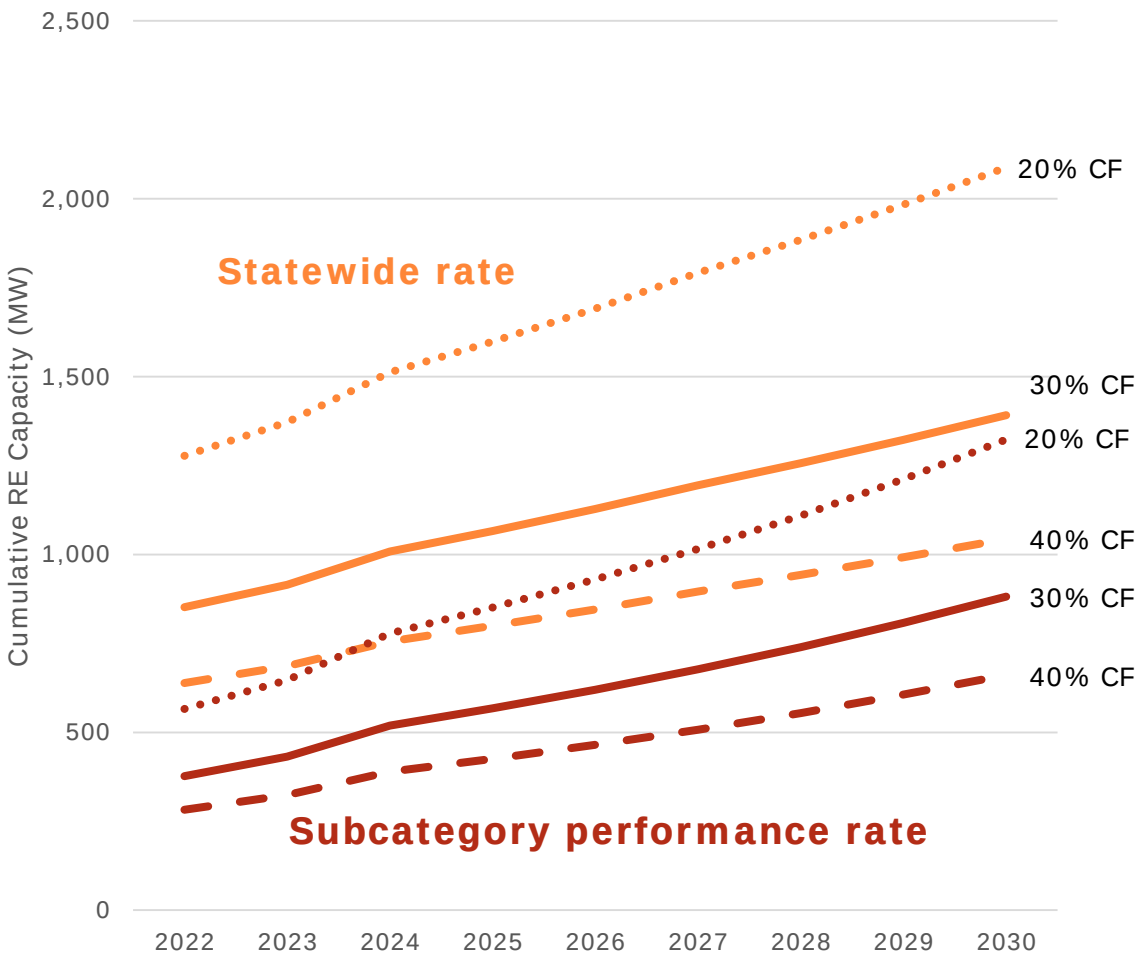
TABLE 8: CUMULATIVE RENEWABLE ENERGY CAPACITY FOR REQUIRED 2030 ERCS

Capacity Factor of Renewable Energy Resource that is Creating ERCs	**Statewide rate goal**	**Subcategory performance rates**	
		Model State Plan	**Federal Plan**
20% Capacity Factor	2,087 MW	1,323 MW	1,323 MW
30% Capacity Factor	1,392 MW	882 MW	882 MW
40% Capacity Factor	1,044 MW	661 MW	661 MW

As compared to the statewide rate goal plan, the number of ERCs required under plans with subcategorized performance rates lessens the compliance burden on the Scenario 1 EGU. If we assumed a renewable energy resource with a 40% capacity factor is the source of all compliance ERCs, the statewide rate goal requires the procurement or construction of 1,044 MW of resources, compared to 661 MW under both the model state plan and federal plan (which use subcategory performance rates).

Additionally, the "quality" of the renewable energy resource creating the ERCs required by the EGU impacts the compliance burden. This is best demonstrated in the chart depicted in Figure 7.

FIGURE 7: CUMULATIVE RENEWABLE ENERGY CAPACITY FOR REQUIRED ERCS VARYING CAPACITY FACTORS (CF)



Under both statewide and subcategorized rate-based plans, the required capacity (in MWs) for ERC-generating renewable resources decreases as the resource's capacity factor goes up. As shown, in a subcategorized performance rate plan, if 30% capacity factor resources are used to meet 2022 compliance requirements, 377 MW of resources must be procured.

However, if 40% capacity factor resources were available, then only 283 MW would need to be built or contracted. This is a "savings" of over 100 MW in the first compliance year alone. This phenomenon holds true for statewide rates, as well as across the compliance period. Note that the slope of the 30% capacity factor line is steeper than that of the 40% capacity factor line. This is because, after the initial compliance year, the required MW capacity of renewable resources to maintain compliance from 2023–2030 is less when higher quality resources are used. For instance, under the subcategorized performance rate plans, procuring 30% capacity factor resources requires 505 additional MWs between 2023 and 2030, while 40% capacity factor resource reduce this incremental compliance burden to 378 MW. This is simply a function of the ERCs being tied to energy production (MWh).

In the analysis described above, the amount (MW) of cumulative installed renewable energy capacity is directly driven by the assumed capacity factor. A higher capacity factor will result in less installed renewable energy, while a lower capacity factor resource will require more. For our analysis, we referenced capacity factor data collected by the National Renewable Energy Laboratory[1] and the Department of Energy.[2] Based on a review of that national data and the nature of this analysis, we feel that the 20%, 30%, and 40% capacity factors are representative of a wide range of resource types and geographic locations.

- *Is there a way other than renewable energy projects to create ERCs?*

Yes. Under the federal plan, ERCs can be created through both renewable energy generation and the re-dispatch of existing NGCC units. Under state plans, there may be additional ways to create ERCs, for example, through energy efficiency projects. For both state and federal rate-based plans, EPA

[1] http://www.nrel.gov/analysis/tech_cap_factor.html
[2] http://energy.gov/eere/wind/downloads/2014-wind-technologies-market-report

envisions a substantial interstate trading market. For purposes of this analysis, renewable energy development was used to provide context for the magnitude of the compliance gap. The re-dispatch of NGCC may create substantial ERCs, but NGCC units will also need ERCs for compliance in states with subcategorized rate plans. Under the proposed federal plan, a partial ERC is created for every hour an existing NGCC unit runs, but running that unit will also create a need for compliance ERCs based on the unit's emissions rate. Because of the flexibility in the CPP for states, and so much detail around ERC creation still yet to be determined in state plans, the renewable energy development used in this analysis is likely the best way at this time to provide context for a compliance gap in a rate-based pathway.

3.1.2 Compliance Gaps (And Implications) Under a Mass-Based Pathway

Scenario **1**
Mass

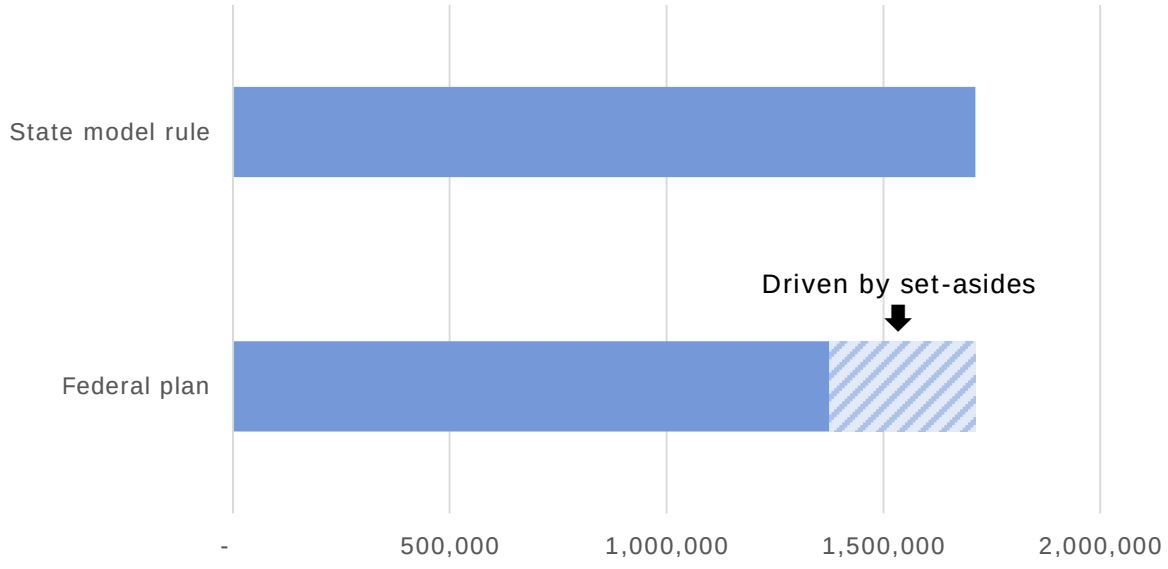
To investigate the impacts of various mass-based pathways on the EGU in Scenario 1, we conducted seven modeling iterations, each featuring various combinations of assumptions emulating both the federal mass-based plan as well as the state model trading rules (with various allowance allocation methodologies). Below, we draw on the findings from this analysis to answer critical questions related to the compliance burden and compliance options for the Scenario 1 EGU under these different mass-based plan types.

- *How does the draft federal mass-based plan (which states may use as a template for state mass-based plans) impact the utility?*

As explained in section 1.2.2, the proposed federal mass-based plan includes various set-asides that reduce the amount of allowances that would be distributed to the affected EGUs based on historical generation. These set-

asides include a set-aside for the CEIP (from the first interim compliance period only), a set-aside to incentivize the development of renewable energy (5% from all periods), and a set-aside to re-distribute allowances based on an output-based adjustment (OBA) that effectively moves allowances from coal units to NGCC units. For the Scenario 1 EGU, the impact of these set-asides is substantial, with about 1.4 million allowances distributed to this EGU in 2030 under a federal plan with the set-asides, and about 1.7 million if there were no set-asides, as illustrated in Figure 8. This example uses the same allocation basis (historical average generation 2010–2012), with the key difference being the use of set-asides. Note that states may create set-asides, especially if they are attempting to address the leakage issue as required by EPA, and the set-asides may be larger or smaller or simply different than the methodology used in the federal plan. This example, however, assumes no set-asides for the state model rule.

FIGURE 8: SCENARIO 1 EGU ALLOWANCE ALLOCATION COMPARISON (2030 ONLY)



The set-asides vary substantially by state and by compliance period. For example, Montana has no NGCC units, so there is no output-based adjustment set-aside, and the final compliance periods therefore have only

the 5% renewable energy set-aside removed from the allowance pool. Nevada, on the other hand, has 17.2% of its final compliance period allowances set-aside for the output-based adjustment, as well as the 5% for renewable energy. See Appendix 1 for look at the set-aside allowances in each compliance period for each state.

- *Assuming a state creates an allowance distribution method different from the proposed federal plan, how do the different allowance distribution methods impact the EGU?*

The method in which states choose to distribute allowances to affected EGUs (or other parties) may have a significant impact on the compliance burden faced by EGUs. To demonstrate this, we calculated the number of allowances our Scenario 1 EGU would receive using several different methods:

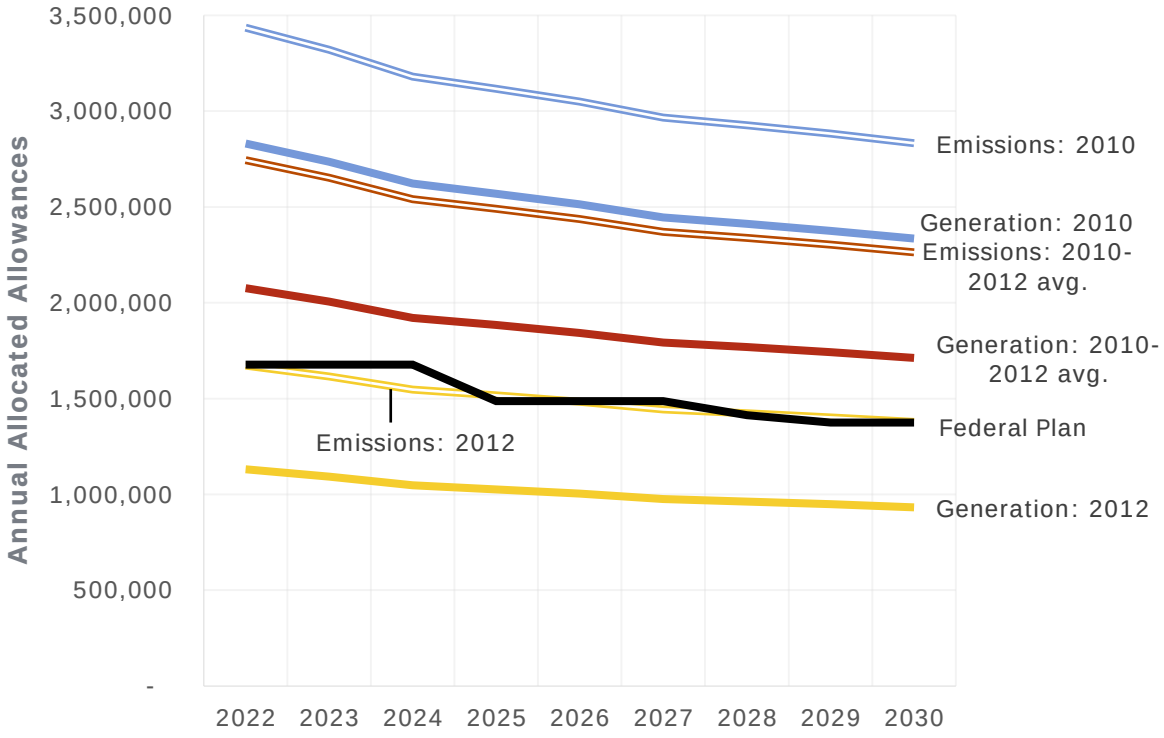
- Federal plan, which uses 2010—2012 historical generation as a baseline for allocation, and has required set-asides
- Three sample state plans, using historical generation with different baselines, and no set-asides
  - 2010 only baseline
  - 2012 only baseline
  - 2010–2012 average baseline
- Three sample state plans, using historical CO_2 emissions with different baselines, and no set-asides
  - 2010 only baseline
  - 2012 only baseline
  - 2010–2012 average baseline

For each of these methods, the number of annual allowances allocated to the Scenario 1 EGU in each year of the compliance period is presented in Figure 9. As seen in the figure, this EGU would receive the most allowances if it were allocated allowances based on 2010 emissions (the top line) and

the fewest allowances if it were allocated allowances based on 2012 generation (the bottom line). The total number of allowances available to all EGUs located in the state does not change in any of the modeling iterations, as that number was set in the CPP by compliance period (see Table 2). It is only the distribution of the allowances to the EGU that change in the modeling iterations.

With our assumed future capacity factor of 75%, the generator would require approximately 3.5 million allowances per year to operate at this level of output (assuming no other improvements to the generator's emission rate). With this in mind, it is worth noting that none of the allocation methods investigated result in compliance for the EGU, that is, even the highest allowance allocation amount modeled quickly falls from 3.4 million to 2.8 million in 2030. The generator would have to either reduce generation to the level commensurate with assigned allowances, procure additional allowances from the market, or some combination of the two.

FIGURE 9: IMPACT OF VARYING ALLOWANCE ALLOCATION METHODS

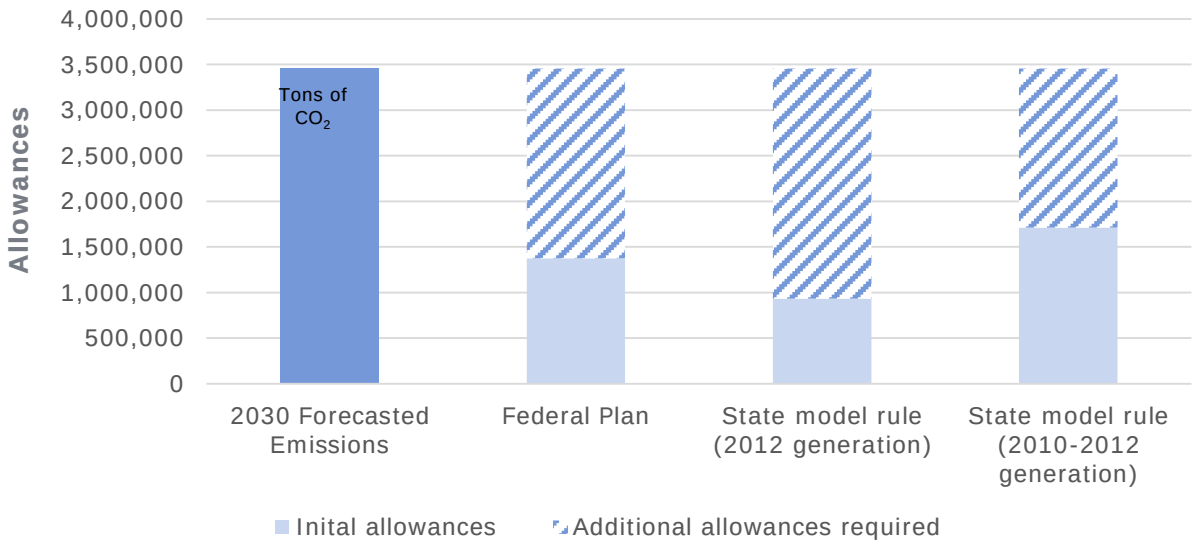


If we assume that the generator will continue to operate at the 75% capacity factor forecasted in the study, it is advantageous to the utility in Scenario 1 to minimize the number of allowances that must be procured from the market. Stated another way, the utility will benefit from the allocation methodology that maximizes the number of allowances allocated to the EGU. In reviewing the data provided above, we can see that methods using emissions or generation (MWh) as the basis for allocations based on 2010 operations result in the most allowances assigned to the EGU. This is explained by the relatively high capacity factor the EGU operated at in 2010 as compared to other years. In 2010, the EGU generated electricity at a capacity factor of 91%, which resulted in this EGU making up a larger portion of Texas's total energy, which in turn resulted in the allocation of more allowances.

The year 2012 provides a strong contrast with 2010 in terms of the unit's operation. During that year, it operated at a 38% capacity factor. This accounts for the relatively low number of allowances available for distribution to the EGU under both emissions- and generation-based approaches (using 2012 as the base year data).

Figure 10 below illustrates the gap ("additional allowances required") under three different allowance allocation methodologies: the federal plan, a state plan with no set-asides based on 2012 generation, and a state plan with no set-asides based on average 2010–2012 generation.

FIGURE 10: IMPACT OF ALLOWANCE DISTRIBUTION METHODOLOGIES



Only the federal plan assumes set-asides; the other allowance distribution methods assume full allocation of allowances with no set-aside. The impact of set-asides can be more significant than the choice of allocation metric (e.g., emissions versus generation).

States will have the option to auction allowances, with or without set-asides, as well as distributing them at no cost. Modeling the potential impact of an

auction, with all the possible permutations, is beyond the scope of this project.

- *What is the range of cumulative allowance requirements needed through 2030 based on the modeling analysis?*

The total number of cumulative allowances needed for compliance through 2030 falls within a wide range, with the lowest number (3.4 million) needed if allowances were allocated based on 2010 emissions with no set-asides, and the highest number (22 million) needed if allowances were allocated based on 2012 historic generation. Note that many state plans are likely to have set-asides, as that might be a way for states to address leakage, a requirement for an EPA-approvable state plan. Table 9 summarizes the cumulative allowance requirements.

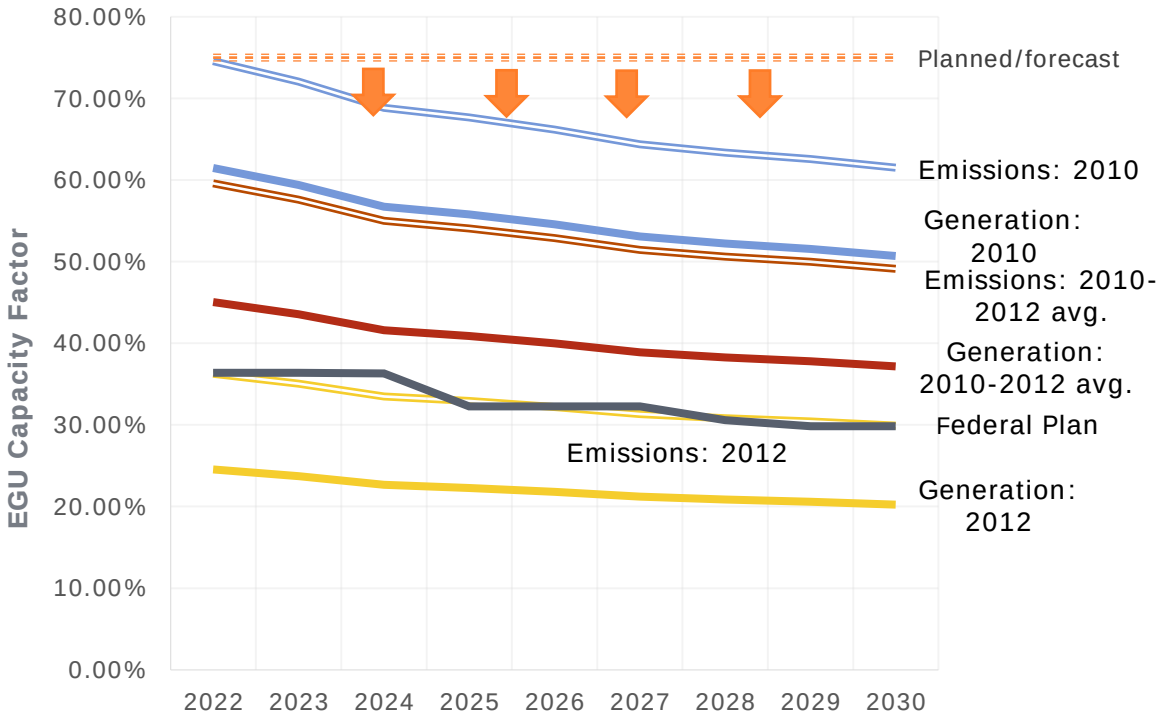
TABLE 9: CUMULATIVE ALLOWANCE REQUIREMENTS THROUGH 2030 FOR VARIOUS ALLOCATION METHODOLOGIES

Plan Type	Includes set-asides?	Allocation Metric	Baseline for Allocation Metric	Cumulative Allowance Requirements
Federal	Yes	Historical Generation	2010–2012 Average	17,466,667
State	No	Historical Generation	2010–2012 Average	14,377,646
			2012	22,000,949
			2010	8,279,605
		Historical Emissions	2010–2012 Average	8,979,533
			2012	17,639,402
			2010	3,411,854

- *How could the EGU be re-dispatched to operate within the allowance allocations?*

Under a mass-based plan, EGUs will have to "retire" one allocated or purchased allowance for each short ton of CO_2 emitted. Thus, one way to achieve compliance in a mass-based plan is to reduce generation such that emissions from the EGU do not exceed the number of allowances available to the EGU. Figure 11 illustrates the implications of this reduction in generation as a compliance measure, with the reduction in capacity factor from the planned 75% for each allowance allocation methodology that was modeled. As with the compliance gap graph, the most severe reduction in capacity factor (down to 20% in 2030) would occur if allowances were distributed based on 2012 generation. This analysis is provided for context of the compliance gap, and should not be interpreted as a credible compliance measure.

FIGURE 11: REDISPATCH AS COMPLIANCE MEASURE



This re-dispatch analysis assumes the EGU only has access to allocated allowances and no other allowances are available from the market, and represents the reduction in generation from historical and planned values that would allow the generation to become CPP compliant.

The reduction in generation is minimized if allowances are distributed under a methodology that uses 2010 data. Re-dispatch is much more severe under scenarios where emission allowances are distributed based on 2012 operations. The federal plan methodology, because of the set-asides, also results in a very drastic re-dispatch. Both of these situations result in 2030 capacity factors below 30%.

The EPA envisions an interstate trading market for allowances. If this EGU could not access that market (because the state in which the EGU is located does not choose interstate trading, for example), the EGU could only turn to the intrastate market. If there were no allowances available intrastate, the situation for the EGU could be dire. Without a complete analysis it is difficult to predict, but given the operations and maintenance (O&M) and fixed costs requirements for an EGU such as the one featured in Scenario 1, it is unlikely that continued operation of the generator at such a low capacity factor would be economical.

3.1.3 Summary and Key Issues: Scenario 1

From the three rate-based modeling iterations for the EGU in this scenario, it's clear that this coal plant benefits from subcategorized performance rates, rather than the statewide rate, in having a lower target. (This is primarily due to the spread between the subcategorized performance rates and this particular state's statewide rate; in states with a smaller spread, it would have less effect.) In addition, states with plans based on subcategorized performance rates rather than statewide rates are able to pursue interstate

trading more easily, without the need for a multi-state plan trading agreement and filing. In a rate-based world, the federal plan had no direct impact on this EGU because this scenario did not have ERCs from energy efficiency directly available to it. The amount of renewable energy capacity that will need to be developed to enable EGUs to comply with this rule will be substantial, although it is unlikely a single compliance measure would be pursued.

From the seven mass-based modeling iterations, it is clear that the set-asides in the federal plan have an impact on the compliance gap for the EGU in this scenario, but some of this effect is masked by the very different operational rates in different years. For this particular EGU, the performance year that determines the allocation distribution matters quite a bit, because the utilization was varied between 2010 and 2012. Distributed allowances under any methodology are unlikely to allow EGUs to run as they have historically, because by design, the CPP will reduce emissions by approximately 32% from 2005 levels nationally by 2030. The reduction in utilization implied by some of the modeled compliance gaps could result in an uneconomic situation for this EGU if intrastate or interstate allowance trading were not available.

The risk of a coal-fired asset becoming uneconomical to operate is more likely if there is no interstate trading of ERCs or allowances. This does not mean the risk disappears if there is interstate trading. Because of the flexibility that EPA is providing the states, it is not possible to realistically model the way trading will work or the cost of compliance instruments at this time.

This particular EGU does not have easy access to “excess” compliance instruments to allow it to run at historical levels. Additional compliance instruments may be available in interstate or intrastate trading markets at a

cost, and the number and cost of these compliance instruments would be determined by a number of factors. For example, some states have significant renewable energy potential, and may generate ERCs from this energy, or this renewable energy may displace fossil-fueled energy to the point that some EGUs have excess allowances. States may have robust energy efficiency performance standards, and those states may allow ERC creation from those programs, or, again, it may reduce the need for fossil-fueled energy such that there are excess allowances. Other states may have retiring EGUs, and those EGUs may have allowances they do not need that could be sold to other EGUs. In some states, excess NGCC capacity may lead to significant re-dispatch, and creation of GS-ERCs. This re-dispatch, because of the lower emission rates of NGCCs, could also free up allowances.

One of the most critical decisions a state will make is whether to pursue a rate-based or mass-based approach. A mass-based approach has several advantages over a rate-based approach from a regulatory perspective. Compliance is measured at the smokestack and this is more familiar to state and federal environmental regulators. A mass-based approach would be easier for states to administer, allows for easier compliance if there are retiring EGUs in the state, and reflects the benefits of energy efficiency programs and renewable energy projects without the need to directly incorporate them (with new administrative procedures) into the state's CPP filing. EPA also points out in its nationwide illustrative analysis that mass-based approaches are significantly more economic. EPA is fairly explicit in its preference for mass-based plans that include a market-based trading program.

In contrast, a rate-based plan will generally be more complex, with more administrative burden. The need to "create" compliance instruments (with attendant measurement and verification requirements) is a key difference

from the mass-based approaches, under which the compliance instruments (allowances) come into being as soon as that pathway is chosen. The rate-based compliance instruments (ERCs) must be created through some action, such as deploying a new energy efficiency program, generating new renewable energy, or building new nuclear capacity. Of course, because of the very different nature of rate- and mass-based approaches, there are naturally some advantages to a rate-based plan. One is the ability to serve unlimited growth from existing resources while staying in compliance (because compliance is intensity based, in an emissions rate per MWh). Also, for those states with nuclear generation under construction, the ability to create vast numbers of compliance instruments (ERCs) from that new nuclear generation would be an advantage under a rate-based approach.

Each state must also consider reliability in their plans. For example, states must show that they have considered reliability in developing their plans through coordination and consultation with the proper reliability and/or planning agencies. The states also have the ability to amend their plans, either temporarily or on a long-term basis, in the event that reliability challenges arise. The shorter and more immediate amendments to state plans are known as the “reliability safety valve,” for which EPA can grant a state a 90-day period to exceed carbon limits during reliability emergencies. EPA believes reliability is most at risk when a specific EGU has a required performance target and no access to trading markets for compliance instruments. Because the proposed federal plans include interstate trading, EPA does not believe any additional evaluation of reliability is needed.

Compliance for the EGU in Scenario 1, as demonstrated by this analysis, may be best achieved through the actions of other players and the existence of robust interstate trading markets for compliance instruments. While this EGU did not have any compliance measure opportunities within the same corporate structure, the Scenario 2 EGU does. We now turn to that scenario.

3.2 Scenario 2: Cross-State Load and EGU

As noted in the introduction to Scenario 1 analysis, mass-based plans and rate-based plans are very different. As in Scenario 1, we will discuss the two plan types in different sections. Unique to Scenario 2, however, is the more immediate need for interstate trading. The EGU in Scenario 2 has, theoretically, access to both renewable energy and energy efficiency as compliance measures. It is theoretical, because as noted earlier, the CPP is not utility regulation that is designed to consider resources or load that cross state lines. The CPP will regulate the EGU based on the location of the EGU. The availability of out-of-state compliance measures to the EGU will depend in large part on whether states file plans that are compatible for trading. Table 10 shows the combination of state plans that would allow for trading or transfer of allowances or ERCs. State A represents the location of the EGU, and State B is the location of the potential compliance measures. It is assumed that a state filing the first three plan types would file interstate trading-ready plans. (The main requirements for an interstate trading-ready plan are the election to trade, EPA approval of the plan, and the use of an EPA-administered or EPA-approved trading platform.)

As noted previously, states are generally restricted to only trade with states on the same plan type, that is, mass with mass, and rate with rate. EPA notes extensively in the CPP that states and utilities already have experience trading under mass-based regulations.

TABLE 10: STATE PLAN COMBINATIONS THAT ALLOW FOR COMPLIANCE INSTRUMENT TRADING

			State A Plan (EGU state)			
			Mass		**Rate**	
			Existing Units	Existing Units + New Source Complement	Subcategorized Rates	Statewide Goal
State B Plan (Load state, or RE state)	**Mass**	Existing Units	Yes	Yes	No*	No
		Existing Units + New Source Complement	Yes	Yes	No*	No
	Rate	Sub-categorized Rates	No	No	Yes	No
		Statewide Goal	No	No	No	Only if States A & B file a multi-state plan

** The one exception would be if State A allowed for the creation of ERCs for out-of-state renewable energy projects, developed 2013 and later, that served load in its state (e.g., through a Power Purchase Agreement). State B could not allocate allowances to the renewable energy project.*

The analysis that follows, first discussing rate and then mass for the EGU in Scenario 2, assumes that if trading or transfer of compliance instruments were allowed, the EGU would take advantage of it to reduce the compliance gap for the EGU.

3.2.1 Compliance Gaps (And Implications) Under a Rate-Based Pathway

Scenario **2**
Rate

As with the EGU in Scenario 1, the compliance gap and the implications were investigated under various rate-based pathways. We evaluated four modeling iterations of rate-based pathways for this scenario, as the element of trading was introduced. The statewide rate and subcategorized rates were analyzed. Within the subcategorized rates, the difference between the federal plan and a model state plan were analyzed. The critical questions for the Scenario 2 EGU follow, with answers again drawn from the modeling.

- *How does the use of the statewide goal versus the subcategorized goals impact the EGU's compliance deficit?*

The EGU for this scenario is located in a state (Wyoming) in which the statewide rate and the subcategorized rate for coal units are very similar. This is because this state has few existing NGCC units. This EGU gains little benefit from the 1,305 lbs CO_2/MWh subcategorized rate in a state with a 1,299 lbs CO_2/MWh statewide rate.

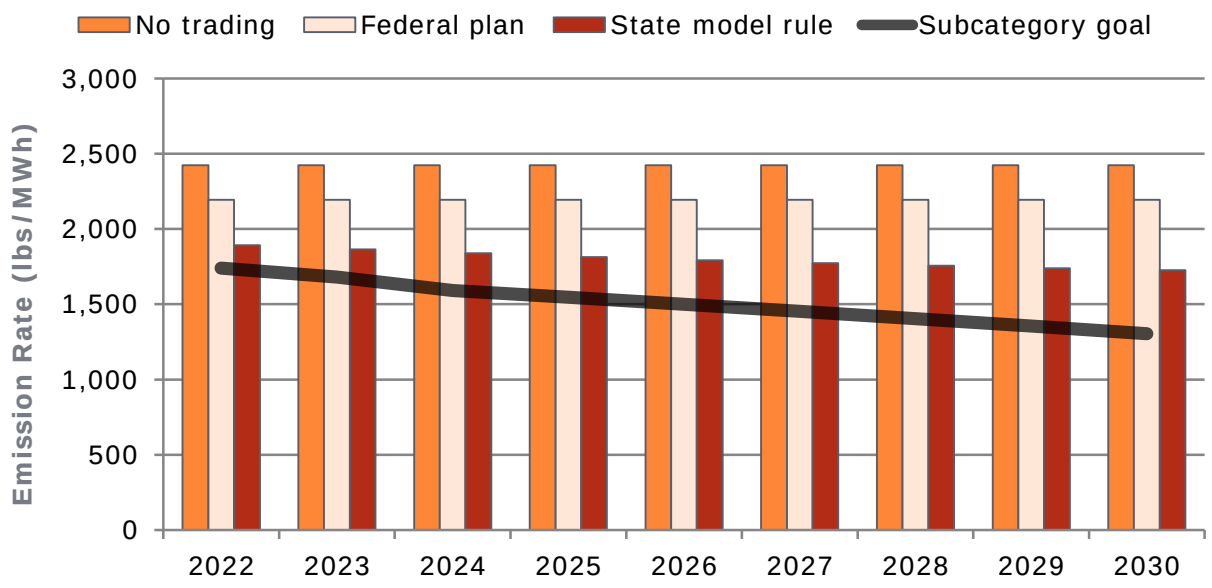
- *How does the proposed federal plan (which is a subcategorized rate plan) impact compliance of the EGU, versus a* state *subcategorized rate plan?*

Both a subcategorized rate federal plan and a subcategorized rate model state plan were investigated in Scenario 2. Recall that the key difference between the proposed rate-based federal plan and potential rate-based state plans is that energy efficiency cannot create ERCs in the proposed federal plan. Because the utility in Scenario 2 has the opportunity through energy efficiency to gain ERCs (assuming state plan compatibility), the modeling for

the rate-based federal plan shows a larger compliance gap than the modeling for the state rate-based plan.

The finding described above is demonstrated in Figure 12, in which the effective emission rates for the EGU are presented for three state plan types. The subcategory rate goal that would be used under each type is also provided (black line). If the bar for the EGU is above the goal, then that can be interpreted to mean the EGU is not in compliance and it would need additional ERCs to further reduce its effective emission rate.

FIGURE 12: COMPARING EFFECTIVE EMISSION RATES UNDER SUBCATEGORY PLANS



Using this platform for comparison, the analysis shows that the EGU would be worst off under a state plan that does not allow trading. Under this type of plan, it would not have access to the energy efficiency and renewable energy ERCs generated in other states. The federal plan only takes advantage of a portion of those ERCs—namely those generated by renewable energy, because ERCs cannot be created through energy efficiency under a federal plan. Because of this, the EGU's effective emission

rate under this plan is slightly lower, and its compliance gap slightly less, than under the "no trading" modeling iteration. Finally, if a state model rule allowed trading of ERCs from energy efficiency as well as renewable energy (and those states in which the ERCs were generated did similarly), then the EGU is able to take full advantage of these credits, and it sees its lowest effective emission rate, and smallest compliance gap, of the three cases.

- *How many cumulative ERCs are needed in 2030 based on the models for Scenario 2?*

Based on assumptions described earlier in this report, we can calculate the annual ERC requirement for the EGU. The requirement is the number of ERCs that would be required to bring that EGU's effective emissions rate into compliance with the modeled plans particular rate-based target. The 2030 cumulative ERC requirement would be the sum of each annual value over the compliance period (2022–2030). The cumulative ERC requirements for Scenario 2 are provided in Table 11.

TABLE 11: CUMULATIVE ERC REQUIREMENTS IN 2030 FOR SCENARIO 2

Plan Type	Performance Standard	Interstate Trading?	Cumulative ERC Requirements
Federal Plan	Subcategorized Performance Rates	Yes	8,586,414
State Plan	Subcategorized Performance Rates	Yes	4,529,735
		No	10,326,468
	Statewide Rate	No	10,462,181

The cumulative ERC analysis supports the same conclusion that we observed when reviewing the effective emission rates of the EGU under different plan types (Figure 12). Plans that allow interstate trading reduce the compliance burden faced by the EGU. In instances when the utility is able to apply all of

its out-of-state energy efficiency and renewable energy ERCs to the EGU's effective emission rate, the compliance burden is minimized.

- *How could that many ERCs be created?*

As noted in the discussion for Scenario 1, EGUs can reduce their effective emission rate by procuring ERCs from renewable generation projects installed after 2012. For Scenario 2, we calculated the total capacity of incremental renewable energy resources that would have to be built or procured for the EGU to operate at its forecasted output (75% capacity factor) throughout the compliance period under the various plan options. The results of this analysis are summarized in Table 12.

TABLE 12: CUMULATIVE RENEWABLE ENERGY CAPACITY REQUIRED FOR 2030 ERCS

Capacity Factor of Renewable Energy Resource that is Creating ERCs	**Statewide rate goal**	**Subcategory performance rates**		
	No trading	**Model State Plan, No trading**	**Model State Plan**	**Federal Plan**
20% Capacity Factor	914 MW	905 MW	478 MW	795 MW
30% Capacity Factor	609 MW	603 MW	318 MW	530 MW
40% Capacity Factor	457 MW	452 MW	239 MW	397 MW

This information simply recasts the findings above about ERCs and emission rates in a more approachable metric. If the utility decided they wanted to operate the plant at the assumed 75% capacity factor, they would have to either build or procure between 239 MW and 457 MW of 40% capacity factor renewable resources by 2030 in order to generate enough ERCs for compliance. The plan types that allow for interstate trading, as discussed above, result in less renewable resources having to be built (or contracted).

3.2.2 Compliance Gaps (And Implications) Under a Mass-Based Pathway

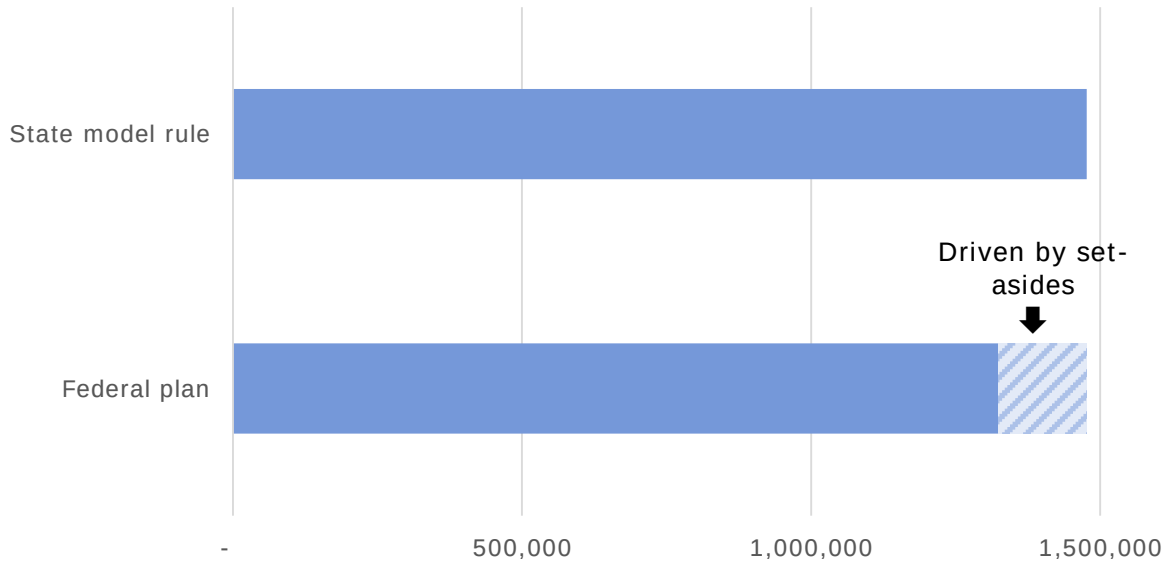
Scenario **2**
Mass

Eight modeling iterations were used to analyze the impacts of various mass-based pathways on the EGU in Scenario 2. The different models, as in Scenario 1, tried to capture various allowance allocation schemes, as well as modeling the federal mass-based plan (with its prescribed allowance allocation). We again use the results to answer critical questions for the mass-based compliance pathways for the EGU in this scenario.

- *How does the draft federal mass-based plan (which states may use as a template for state mass-based plans) impact the utility?*

The impact of the federal plan, with its prescribed set-asides, is small in Wyoming. This is because the set-aside for the output-based adjustment is smaller than in many states. NGCC units within a state determine the size of the output-based-adjustment set-aside, and since Wyoming is overwhelmingly coal-fired for its affected EGUs, this set-aside is therefore small. Figure 13 shows the impact of the set-aside for the EGU in this scenario.

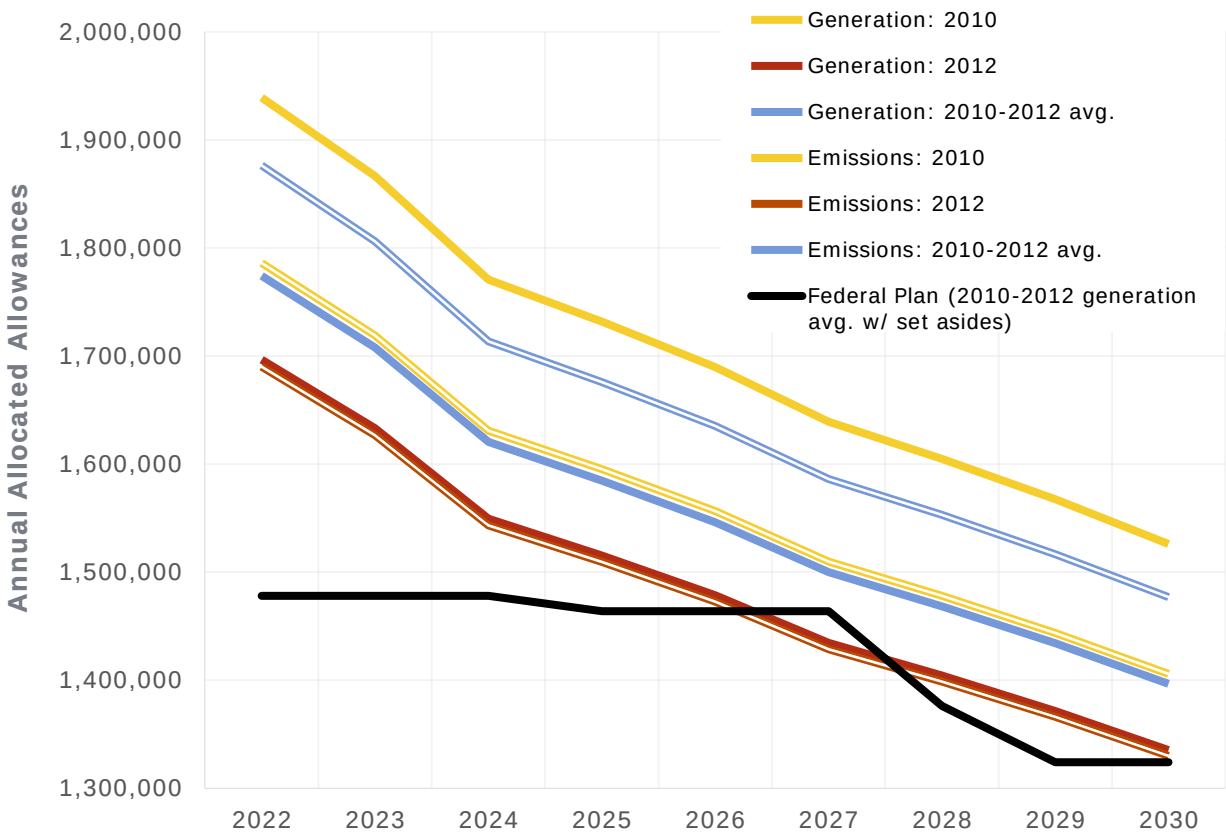
FIGURE 13: SCENARIO 2 EGU ALLOWANCE ALLOCATION COMPARISON (2030 ONLY)



- *Assuming a state creates an allowance distribution method different from the proposed federal plan, how do the different allowance distribution methods impact the EGU?*

Unlike the EGU in Scenario 1, the capacity factor and emissions did not vary significantly from 2010 to 2012. The range of allowances needed to comply is much narrower (as will be seen clearly when cumulative allowance requirements are presented in the next section). The federal plan, with its prescribed set-asides, has a more noticeable impact on this EGU, even though the output-based-adjustment set-aside is small in Wyoming. Because there is less variability in operations year to year for this EGU, the impact of *any* set-aside is more apparent. The federal plan (black line, near bottom) reduces the number of allowances available for allocation to this EGU, thus creating the largest compliance gap.

FIGURE 14: IMPACT OF VARYING ALLOWANCE ALLOCATIONS METHODS (SCENARIO 2)



- *What is the range of cumulative allowance requirements needed for compliance through 2030?*

The range of cumulative allowances needed during the compliance period varies across the different plan types and allowance allocation methods. In Table 13, we summarize the cumulative allowance requirements (through 2030) for the EGU under a number of different state plans. Assuming the generator continued to operate at a 75% capacity factor, the cumulative allowance requirement represents the number of allowances that would need to be procured *beyond* those already assigned to the generator via the various allocation methodologies. The cumulative allowance requirement was greatest (7.3 million) under the Federal Plan because the overall bucket of

allowances under that plan type is reduced by the set-asides. Because of this, the generator starts with fewer allowances and must procure more *incremental* allowances to maintain the same operation. The lowest number (4.9 million) of incremental allowances required for continued operation at a 75% capacity factor would be under a state model rule where allowances are assigned based on 2010 historical generation. Distributing allowances via 2010 historical generation benefits the EGU because it operated at a relatively high 83% capacity factor in 2010, meaning that it made up a larger proportion of the state's generation and thus was assigned a larger portion of allowances.

TABLE 12: CUMULATIVE ALLOWANCE REQUIREMENTS THROUGH 2030 FOR VARIOUS ALLOCATION METHODOLOGIES

Plan Type	Includes set-asides?	Allocation Metric	Baseline for Allocation Metric	Cumulative Allowance Requirements
Federal	Yes	Historical Generation	2010–2012 Average	7,338,444
State	No	Historical Generation	2010–2012 Average	5,348,368
			2012	6,769,087
			2010	4,852,828
		Historical Emissions	2010–2012 Average	6,155,477
			2012	6,822,905
			2010	6,063,235
		Auction (approximated)	New source complement	6,467,373

It is worth noting that aside from the federal plan, none of the plans investigated included set-asides. States may ultimately decide to use set-asides as a means to address leakage or for other policy-related reasons. If this were to happen, the allowance requirements in Table 12 would be understated, since the state-mandated set-asides would presumably reduce

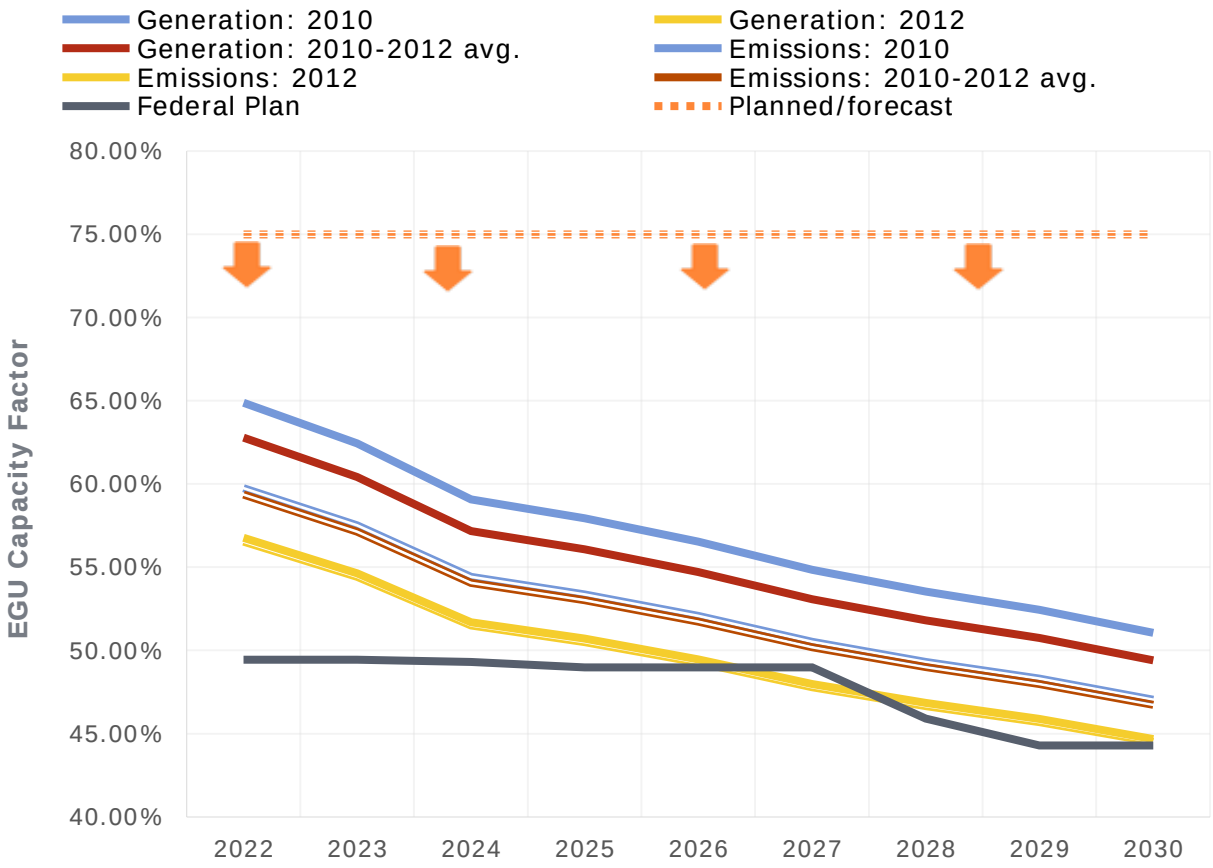
the size of the bucket for allowance distribution, thereby requiring the EGU in Scenario 2 to procure allowances in excess of what is presented here.

- *How could the EGU be re-dispatched to operate within the allowance allocations?*

In Scenario 2, we make the assumption that the EGU desires to continue operation at a 75% capacity factor throughout the compliance period. In the analysis discussed above, we reviewed the number of allowances that would have to be procured across the compliance period in order to allow for such operation (since EGU's must "retire" one allowance for each short ton of CO_2 emitted). However, an alternative approach towards compliance would be for the utility to reduce generation from the EGU such that its emissions do not exceed the number of allowances allocated to the unit under the various plans. This approach was used in the Scenario 1 analysis, and is investigated for Scenario 2 here.

Figure 15 shows the reduction in the EGU's generation (from the planned 75%) that would be required for the generator to reach compliance under each plan type and allocation methodology studied. Looking at the 2030 timeframe, the most severe reductions in output from the generator are required under the federal plan and under a state model rule plan in which allowances are distributed based on 2012 historical generation or emissions. In all three instances, the generator would need to operate slightly below a 45% capacity factor in order to have its emissions not exceed the number of assigned allowances.

FIGURE 15: REDISPATCH AS COMPLIANCE MEASURES



Regardless of the plan type (state versus federal) or allocation methodology, none of the re-dispatch solutions look attractive to the EGU. Even in the best case, in which the generator receives its allowance under a state plan using 2010 generation as the allocation method, the capacity factor at which the EGU needs to operate in order to be in compliance still approaches 50% by 2030.

Importantly, this analysis gives context to the compliance gap and is likely not a credible compliance measure on its own for this EGU. The chart also assumes the EGU only has access to *allocated* allowances. If the EGU was able to procure allowances from the market, in addition to those it is allocated, the forecasted capacity factor of the EGU could be maintained (at

some cost, of course). Given that EPA has openly supported an interstate trading market for allowances, a compliance option that involves maintaining the forecasted capacity factor through procured allowances is possible unless the state in which the EGU is located chose not to pursue interstate trading and the intrastate market did not have sufficient excess allowances.

- *How does the new source complement impact the EGU in Scenario 2?*

The EPA's final rule includes a "new source complement" for each state, which is an EPA-calculated *incremental* budget of emission allowances that would be added to the state's original allowance budget if new sources are included in the state compliance plan. The approach is intended to address the risk of "leakage" from existing NGCC's to new fossil units.

There are a number of challenges associated with modeling the potential impacts of the new source complement. First, there are many methods through which allowances might be distributed under a state plan regulating emissions from both new and existing EGUs. Many of these methods are dependent on the observed (i.e., output-based) or forecasted generation, which is difficult to estimate. Alternatively, the state could attempt to create a plan where allowances are auctioned to generators, which is also equally difficult to model and anticipate (and outside the scope of this work). Lastly, since new resources would presumably receive some of the state allowances, the number and capacity of new EGUs could impact the number of allowances received by existing EGUs.

These issues notwithstanding, we attempted to estimate the impacts of a new source complement plan on the EGU in Scenario 2 by relying on the following data and methodologies:

- Existing EGUs and their forecasted generation and emissions for the compliance period were gathered from public sources such as utility Integrated Resource Plans;
- New EGUs and their forecasted generation and corresponding emissions were also gathered from public sources;
- The state mass allocation "bucket" was increased commensurate with the new source complement in the Clean Power Plan Final Rule Technical Documents (about 11.3 million *additional* allowances for Wyoming); and
- The state allowances were distributed to both new and existing EGUs in proportion to their forecasted generation.

By following these steps, we allocated allowances to the EGU (and all other EGUs in the state). Forecasted generation was used to assign the allowances because of two main drivers: (1) using historical data would not be practical since new EGUs would not receive any allowances under such an approach; and (2) absent more advanced cost-of-compliance and market simulation modeling, we felt that forecasted generation most closely emulated an auction for the allowances, which we feel is a plausible distribution method for such a plan. Conceptually, if an EGU owner was forecasting the unit to operate more (or less), they would attempt to procure emission allowances roughly in line with that generation forecast.

The EGU's cumulative allowance requirement under the modeled new source complement type plan is just over 6.4 million, as shown in Table 13 (page 52). The table also lets us compare that result with the several other different plan types. Based on our methodology, the EGU would fare better under a new source complement plan than it would under the federal plan (7.3 million allowances needed). It would also require fewer allowances over the 2022–2030 compliance period than a state model rule plan that distributes allowances using 2012 generation or 2012 emissions and has no

set-asides. However, a state model rule plan that has no set-asides and that distributes allowances using either 2010–2012 average generation or 2010 generation will have a lower compliance burden than the new source complement plan. The difference in cumulative allowance requirements is not substantial in many of these runs, indicating that, as modeled for this particular EGU, the pathway of mass-based with new source complement does not stand out as particularly harmful or beneficial in this scenario.

This comparison of cumulative allowance requirements as shown in Table 13, and the relative position of the modeled new source complement plan, is subject to a number of key variables. Perhaps most importantly is the way the 11.3 million new source complement allowances would be divided up based on forecasted generation. For instance, if a generator were to retire in our modeling, its allowances would essentially be “freed up” and those units whose forecasted energy increased after their retirement would get a larger portion of those allowances.

As demonstrated, modeling of the new source complement is complex and many of the nuances of its implementation will be left up to the states to initially propose to the EPA. Thus, the modeling of the new source complement plan type is directional in nature as we did not investigate every potential state plan type that might involve the new source complement.

The lack of clear modeling direction is partly driven by the fact that the EPA does not feel that they have the authority to regulate new EGUs under Section 111(d). Thus, the proposed federal plan does not include the new source complement. While states may have to pass a number of state laws to enable this type of plan, it does appear to organize and streamline the regulatory process for new and existing EGUs.

3.2.3 Summary and Key Issues: Scenario 2

One of the key differences between Scenario 1 and Scenario 2 is the opportunity for the EGU in Scenario 2 to take advantage of renewable energy built after 2012 and energy efficiency savings as part of its compliance strategy. This opportunity will be dependent on the decisions by various states about compliance pathways and whether to include interstate trading. As seen in the modeling iterations, the availability of interstate trading to take advantage of these opportunities consistently benefits the EGU's ability to comply. Recall that interstate trading is easiest with mass-based plans (either with or without the new source complement) and subcategorized rate-based plans. With these plan types, there is no need for multi-state trading plans or compliance filings. States need only indicate they will accept compliance instruments from other states, will allow their compliance instruments to be used in other states, use an EPA-approved or EPA-administered trading platform, and have an approved plan.

From the compliance analysis conducted for the EGU in this scenario, some conclusions may be drawn. The benefits were not as great to the EGU if the state were to adopt subcategorized performance rates rather than a statewide rate. This is because the spread between the statewide rate and the subcategorized rate for a coal plant is quite narrow in Wyoming. The difference in cumulative ERC requirements between a statewide-rate plan and a subcategorized-rate plan is small (10.5 million ERCs versus 10.3 million, as seen in Table 11 on page 47). However, there is still the inherent value in the ease of interstate trading with the subcategorized rate pathway.

The modeling of the federal rate-based plan demonstrated how the inability to count energy efficiency-derived ERCs increased the EGU's compliance requirements. The difference in cumulative ERC requirements is substantial: 8.6 million ERCs would be required if this EGU could not credit energy

efficiency ERCs towards compliance versus 4.5 million ERCs, if it could (as seen in Table 11 on page 47). More broadly, the lack of ERCs generated through energy efficiency programs would reduce the pool of compliance ERCs and likely increase their costs.

Turning to the eight mass-based model iterations, many of the conclusions are centered on the impact of the set-asides and the distribution methodology for the allowances. The modeling clearly showed the impact of the proposed federal plan set-asides, in reducing the pool of allowances to be distributed to EGUs. This is true even in Wyoming, where the NGCC output-based adjustment is small due to the dominance of coal-fired units. While some NGCC units might receive additional allowances from the output-based-adjustment set-aside, coal units, under the proposed federal plan, would clearly be negatively impacted from these set-asides. Because the operational history of this EGU did not vary as significantly as the one in Scenario 1 in the years 2010–2012, the compliance gap analysis showed a smaller impact from the allowance distribution metric than from set-asides. If the modeling had included an EGU with little change in operational history but located in a state with greater set-asides, the impact would be even more pronounced. As has been noted previously, the allocation method (including the use of set-asides) that a state chooses can be very controversial, and can have a significant impact on the compliance gap, and costs, for an EGU.

The illustrative compliance strategy of operating at a lower capacity factor was particularly severe in Scenario 2, with the best case requiring the EGU to operate close to a 50% capacity factor in order to comply with the CPP performance standard by 2030. This again reinforces the need for interstate trading. Interstate trading provides EGUs with more compliance flexibility and will generally allow for lower-cost compliance at the state level.

However, interstate trading does not necessarily mean a favorable economic outcome or operational performance for any one particular EGU.

As noted earlier, a state's decision to pursue a rate-based compliance pathway versus a mass-based one will be critical. For the EGU in this scenario, under a rate-based pathway, renewable energy and the energy efficiency program could translate directly into the creation of ERCs. Under a mass-based pathway, the impact is indirect: theoretically, the generator runs less as it is displaced by renewable energy and demand is lower due to energy efficiency savings. The indirect impacts of renewable energy and energy efficiency would be seen "at the smokestack," but would not necessarily be directly involved in a CPP compliance plan if the renewable energy, or the energy efficiency program, were in a mass-based state. While there are nearly endless permutations of compliance situations in which load, renewable energy, and EGUs are located in various states and governed by different plans, it is critical to remember that compliance for an EGU is governed by the physical location of that EGU.

As discussed earlier in this paper, states have the option to participate in the CEIP, which provides additional incentive for early investments during 2020 and 2021 in clean energy (wind and solar) and energy efficiency in low-income communities. A state would grant qualifying projects "early action credits" in the form of either allowances or ERCs. The EPA would match the credits (up to a limit of 300 million tons of CO2 if all states participate), and the qualifying projects receiving the ERCs or allowances would be able to trade these credits with EGUs during the first compliance period (2022-2024). For the purposes of this analysis, one of the most important traits of the CEIP is that allowances and ERCs "granted" by the states to qualified early action projects come from the pool of allowances or future ERCs that would be distributed during the 2022-2024 timeframe. Any state that participates in the CEIP will have this set-aside from the first compliance

period pool of allowances, or, in the case of rate-based states, will have to determine how to "reduce" the awardable ERCs from the first compliance period to maintain compliance stringency. Thus, to some companies that own affected EGUs but do not pursue early action projects, the CEIP reduces the pool of compliance instruments in the first interim compliance period and could change the compliance picture for the EGU.

Compliance for the EGU in Scenario 2, just as with the EGU in the first Scenario, may be best achieved through the actions of other players and the acquisition of compliance instruments. The energy efficiency opportunity for this EGU is particularly strong, however, and whether that translates to running the EGU less (indirect impact on compliance in a mass-based pathway) and/or the creation of ERCs (direct impact through the creation of compliance instruments in a rate-based pathway) will depend on the choices made by the states in which the EGU and the load are located.

4.0 CONCLUSIONS

APPA members are interested in better understanding how various CO_2 emissions trading schemes might enable compliance under the Clean Power Plan rule. With the release of the proposed federal plan and model trading rules, various models can be constructed for specific EGUs or states. APPA commissioned this study to review two specific scenarios within this context. The manner in which an individual EGU will comply with the Clean Power Plan, because of the flexibility that EPA left to the states, is still largely indeterminable. It is important to note that the compliance obligation in almost all cases will fall to the EGU. And the state in which that EGU is located will decide the potential compliance options. The first major decision a state will make will be whether to pursue a rate- or a mass-based pathway.

Rate versus mass

It is critical that EGUs evaluate whether they are better off under a rate- or mass-based plan because, as shown by this analysis, the implementation of each can and will have a dramatically different impact on an EGU's ability to comply with the CPP. Mass-based approaches are familiar to the industry, easy to administer, and often considered more economic from a national perspective. However, there are concerns about how growth would be addressed in mass-based plans, and the confusion of preventing leakage to new sources could be a challenge in some states. Alternatively, rate-based plans would be more complex, "new" to the industry (and not well understood), while also having significant administrative burden.

Under rate-based pathways, action is required to generate compliance instruments: either the deployment of an energy efficiency program, or the procurement/development of new renewable energy or nuclear resources. The availability (and cost) of compliance instruments is therefore very dependent on these specific actions. In contrast, mass-based pathways will demonstrate compliance "at the smokestack," and the impact of renewable energy and energy efficiency will be indirect, as EGUs (in general) run less.

Of course, another critical issue when considering rate versus mass is the compliance pathway that other states choose. Since mass will trade with mass, and rate with rate, the number of states choosing a mass- or rate-based compliance approach will determine the liquidity of the market for compliance instruments and impact the cost of those compliance instruments. There is a risk of higher compliance costs for an EGU being located in one of a handful of rate-based states if most of the nation chooses mass.

Interstate trading

As noted throughout this analysis, large-scale interstate trading will provide individual EGUs the flexibility to determine the best compliance strategy. This strategy might include operating at a lower capacity factor, developing energy efficiency programs, contracting or developing new renewable energy, acquiring compliance instruments, or some combination of the above. Without interstate trading to make compliance instruments available broadly, each EGU is forced into a narrower set of potentially higher-cost choices for compliance. States that choose not to pursue interstate trading—effectively "withholding" their compliance instruments from the market—affect the liquidity and price of the compliance instruments in other states.

Interstate trading will also reduce the impact of the CPP on reliability. While there is nothing in the CPP that ensures must-run plants will also be economic, the availability of compliance instruments from a liquid market at least ensures that EGUs will not face shutdown or operating at a lower capacity factor as their *only* compliance strategy.

Compared to the draft CPP, the final CPP is more amenable to trading as a compliance strategy. EPA has indicated it will administer trading programs for both mass- and rate-based plans. There is no need for states to form multi-state trading agreements or tracking and trading platforms, unless they choose the statewide rate pathway.

Rate-based pathways: subcategorized vs. statewide rate-based plans

For any particular EGU, a preference for a statewide rate versus a subcategorized rate, if the state pursued a rate-based compliance pathway, will be determined by the spread between these two rates in the EGU's state. The compliance gap is inherently lower if a coal-fired EGU must only achieve a "coal" subcategorized rate, but this preference diminishes if the

statewide rate is very close to that rate anyway (as it is in Montana, North Dakota, West Virginia, and Wyoming; see Table 1). However, in instances where the statewide rate and the subcategorized rate are similar, a subcategorized rate plan may ultimate ease the EGU's compliance burden because this plan type would allow EGUs to pursue interstate ERC trading more easily. With more options and sources for ERCs, the ultimate cost borne by the EGU could come down.

Rate-based pathways: federal plan versus state model plan

A primary difference between the federal subcategorized-rate plan and a model state subcategorized-rate plan is the exclusion of energy efficiency. Any state complying under a federal plan would not be able to turn the impacts of their energy efficiency programs into compliance instruments, which could be a significant disadvantage. If a state chooses to submit a state plan under a rate-based pathway, then EGUs would benefit if those state plans include issuing compliance instruments for the savings resulting from energy efficiency. That is, it would improve the liquidity of the ERC market and lower ERC costs if states choose to include energy efficiency. As was clearly seen in Scenario 2, the potential for energy efficiency as a compliance measure is substantial. Energy efficiency is also usually regarded as a low-cost measure, especially compared to the deployment of new nuclear or new renewable energy.

Mass-based pathways: allocation methods

As noted throughout this analysis, the allocation of allowances has important implications for the ability of EGUs to comply with the CPP. EPA has stated it views allocation as an "asset distribution" issue and gives broad flexibility to the states in choosing a methodology. For the methods explored in this paper, the inclusion of set-asides and the method of distribution can significantly change the compliance gap, and subsequently, the compliance

costs. An auction method, whereby no allowances (or only a few) were distributed without cost to EGUs, would of course significantly affect the compliance costs for EGUs.

Mass-based pathways: the federal mass-based plan

The advantage of the federal plan's methodology for allowance allocation is that if a state chooses it, the plan would be presumptively approvable, and the state could sidestep the policy decisions and negotiations with the many stakeholders that would otherwise be required to develop its own methodology. We believe few states will choose to adopt the federal plan/model rule's distribution methodology exactly as written. Most important for the vast majority of EGUs will be whether a state auctions or freely distributes allowances. The second most important issue will be the size and manner of set-asides, especially for coal units (which would likely have no opportunity to "earn back" output-based-adjustment allowances). Lastly, each EGU should be familiar with its operational history and the potential impact of the different metrics a state could choose to allocate allowances (e.g., emissions, generation, multi-year averages or a single year).

Mass-based pathways: the new source complement pathway

The flexibility given to the states is most apparent when trying to model a mass-based pathway that includes the new source complement. Under this pathway, states may choose not only the allocation method (with an auction being a possibility) but also the size of the bucket (the number of total allowances). The modeling iterations under Scenario 2 for this pathway showed it to be "middle of the pack." That is, if the modeling is used as a directional indicator, there is no reason to believe that an EGU would distinctly benefit or be harmed by the New Source Complement pathway,

compared to other mass-based pathways, if reasonable assumptions are used for all the variables.

The Clean Power Plan represents the EPA's initial effort to regulate carbon emissions from the U.S. electric sector. The implications are wide-ranging and pervasive for the sector as a whole – and especially for EGUs. As states and their stakeholders grapple with the complexities of the various plan types, attempting to optimize economic, political, and environmental outcomes, EGUs should thoroughly consider their advocacy options and develop detailed strategies such that they can provide meaningful input and guidance into these critical state decision-making processes, which will unfold over the coming months and years.

5.0 Appendix 1

APPENDIX 1

Propsoed Federal Plan Set-Asides Allowances in Each Compliance Period

Alabama

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	66,164,470	3,122,306		3,308,224	9.72
Interim Phase 2	60,918,973	0	4,185,496	3,045,949	11.87
Interim Phase 3	58,215,989	0	4,185,496	2,910,799	12.19
Final	**56,880,474**	**0**	**4,185,496**	**2,844,024**	12.36

Arizona

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	35,189,232	1,719,618		1,759,462	9.89
Interim Phase 2	32,371,942	0	4,197,813	1,618,597	17.97
Interim Phase 3	30,906,226	0	4,197,813	1,545,311	18.58
Final	**30,170,750**	**0**	**4,197,813**	**1,508,538**	18.91

Arkansas

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	36,032,671	2,187,230		1,801,634	11.07
Interim Phase 2	32,953,521	0	2,102,538	1,647,676	11.38
Interim Phase 3	31,253,744	0	2,102,538	1,562,687	11.73
Final	**30,322,632**	**0**	**2,102,538**	**1,516,132**	11.93

California

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	53,500,107	218,846		2,675,005	5.41
Interim Phase 2	50,080,840	0	8,458,604	2,504,042	21.89
Interim Phase 3	48,736,877	0	8,458,604	2,436,844	22.36
Final	**48,410,120**	**0**	**8,458,604**	**2,420,506**	22.47

Colorado

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	35,758,322	2,223,192		1,789,266	11.22
Interim Phase 2	32,654,483	0	1,348,187	1,632,724	9.13
Interim Phase 3	30,891,824	0	1,348,187	1,544,591	9.36
Final	**29,900,397**	**0**	**1,348,187**	**1,495,020**	9.51

Connecticut

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mas budget
Interim Phase 1	7,555,787	69,415		377,789	5.92
Interim Phase 2	7,108,466	0	1,090,811	355,423	20.35
Interim Phase 3	6,955,080	0	1,090,811	347,754	20.68
Final	**6,941,523**	**0**	**1,090,811**	**347,076**	20.71

APPENDIX 1

Propsoed Federal Plan Set-Asides Allowances in Each Compliance Period

Delware

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	5,348,363	138,392		267,418	7.59
Interim Phase 2	4,963,102	0	649,190	248,155	18.08
Interim Phase 3	4,784,280	0	649,190	239,214	18.57
Final	**4,711,825**	**0**	**649,190**	**235,591**	18.78

Florida

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	119,380,477	3,230,248		5,969,024	7.71
Interim Phase 2	110,754,683	0	12,102,688	5,537,734	15.93
Interim Phase 3	106,736,177	0	12,102,688	5,336,809	16.34
Final	**105,094,704**	**0**	**12,102,688**	**5,254,735**	16.52

Georgia

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	54,258,931	2,755,623		2,712,897	10.08
Interim Phase 2	49,855,082	0	3,563,104	2,492,754	12.15
Interim Phase 3	47,534,817	0	3,563,104	2,376,741	12.50
Final	**46,346,846**	**0**	**3,563,104**	**2,317,342**	12.69

Idaho

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	1,615,518	14,929		80,776	5.92
Interim Phase 2	1,522,826	0	246,638	76,141	21.20
Interim Phase 3	1,493,052	0	246,638	74,653	21.52
Final	**1,492,856**	**0**	**246,638**	**74,643**	21.52

Illinois

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	80,396,108	5,968,721		4,019,805	12.42
Interim Phase 2	73,124,936	0	1,598,615	3,656,247	7.19
Interim Phase 3	68,921,937	0	1,598,615	3,446,097	7.32
Final	**66,477,157**	**0**	**1,598,615**	**3,323,858**	7.40

Indiana

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	92,010,787	5,754,076		4,600,539	11.25
Interim Phase 2	83,700,336	0	1,106,150	4,185,017	6.32
Interim Phase 3	78,901,574	0	1,106,150	3,945,079	6.40
Final	**76,113,835**	**0**	**1,106,150**	**3,805,692**	6.45

APPENDIX 1

Propsoed Federal Plan Set-Asides Allowances in Each Compliance Period

Iowa

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	30,408,352	2,191,183		1,520,418	12.21
Interim Phase 2	27,615,429	0	492,510	1,380,771	6.78
Interim Phase 3	25,981,975	0	492,510	1,299,099	6.90
Final	**25,018,136**	**0**	**492,510**	**1,250,907**	6.97

Kansas

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	26,763,719	2,115,630		1,338,186	12.90
Interim Phase 2	24,295,773	0	62,257	1,214,789	5.26
Interim Phase 3	22,848,095	0	62,257	1,142,405	5.27
Final	**21,990,826**	**0**	**62,257**	**1,099,541**	5.28

Kentucky

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	76,757,356	4,952,862		3,837,868	11.45
Interim Phase 2	69,698,851	0	288,730	3,484,943	5.41
Interim Phase 3	65,566,898	0	288,730	3,278,345	5.44
Final	**63,126,121**	**0**	**288,730**	**3,156,306**	5.46

Fort Mojave Tribe

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	636,876	5,885		31,844	5.92
Interim Phase 2	600,334	0	248,127	30,017	46.33
Interim Phase 3	588,596	0	248,127	29,430	47.16
Final	**588,519**	**0**	**248,127**	**29,426**	47.16

Navajo Nation

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	26,449,393	1,623,066		1,322,470	11.14
Interim Phase 2	23,999,556	0	-	1,199,978	5.00
Interim Phase 3	22,557,749	0	-	1,127,887	5.00
Final	**21,700,587**	**0**	-	**1,085,029**	5.00

Uintah & Ouray Reservation

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	2,758,744	175,509		137,937	11.36
Interim Phase 2	2,503,220	0	-	125,161	5.00
Interim Phase 3	2,352,835	0	-	117,642	5.00
Final	**2,263,431**	**0**	-	**113,172**	5.00

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Louisiana

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	42,035,202	1,497,428		2,101,760	8.56
Interim Phase 2	38,461,163	0	2,207,879	1,923,058	10.74
Interim Phase 3	36,496,707	0	2,207,879	1,824,835	11.05
Final	**35,427,023**	**0**	**2,207,879**	**1,771,351**	11.23

Maine

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	2,251,173	20,739		112,559	5.92
Interim Phase 2	2,119,865	0	563,925	105,993	31.60
Interim Phase 3	2,076,179	0	563,925	103,809	32.16
Final	**2,073,942**	**0**	**563,925**	**103,697**	32.19

Maryland

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	17,447,354	972,775		872,368	10.58
Interim Phase 2	15,842,485	0	103,762	792,124	5.65
Interim Phase 3	14,902,826	0	103,762	745,141	5.70
Final	**14,347,628**	**0**	**103,762**	**717,381**	5.72

Massachusetts

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	13,360,735	170,471		668,037	6.28
Interim Phase 2	12,511,985	0	2,439,991	625,599	24.50
Interim Phase 3	12,181,628	0	2,439,991	609,081	25.03
Final	**12,104,747**	**0**	**2,439,991**	**605,237**	25.16

Michigan

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	56,854,256	3,727,861		2,842,713	11.56
Interim Phase 2	51,893,556	0	2,105,786	2,594,678	9.06
Interim Phase 3	49,106,884	0	2,105,786	2,455,344	9.29
Final	**47,544,064**	**0**	**2,105,786**	**2,377,203**	9.43

Minnesota

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	27,303,150	2,002,903		1,365,158	12.34
Interim Phase 2	24,868,570	0	909,724	1,243,429	8.66
Interim Phase 3	23,476,788	0	909,724	1,173,839	8.87
Final	**22,678,368**	**0**	**909,724**	**1,133,918**	9.01

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Mississippi

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	28,940,675	357,307		1,447,034	6.23
Interim Phase 2	26,790,683	0	3,132,671	1,339,534	16.69
Interim Phase 3	25,756,215	0	3,132,671	1,287,811	17.16
Final	**25,304,337**	**0**	**3,132,671**	**1,265,217**	17.38

Missouri

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	67,312,915	3,771,322		3,365,646	10.60
Interim Phase 2	61,158,279	0	815,210	3,057,914	6.33
Interim Phase 3	57,570,942	0	815,210	2,878,547	6.42
Final	**55,462,884**	**0**	**815,210**	**2,773,144**	6.47

Montana

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	13,776,601	1,310,344		688,830	14.51
Interim Phase 2	12,500,563	0	-	625,028	5.00
Interim Phase 3	11,749,574	0	-	587,479	5.00
Final	**11,303,107**	**0**	-	**565,155**	5.00

Nebraska

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	22,246,365	1,481,695		1,112,318	11.66
Interim Phase 2	20,192,820	0	144,635	1,009,641	5.72
Interim Phase 3	18,987,285	0	144,635	949,364	5.76
Final	**18,272,739**	**0**	**144,635**	**913,637**	5.79

Nevada

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	15,076,534	336,288		753,827	7.23
Interim Phase 2	14,072,636	0	2,326,529	703,632	21.53
Interim Phase 3	13,652,612	0	2,326,529	682,631	22.04
Final	**13,523,584**	**0**	**2,326,529**	**676,179**	22.20

New Hampshire

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	4,461,569	107,798		223,078	7.42
Interim Phase 2	4,162,981	0	542,721	208,149	18.04
Interim Phase 3	4,037,142	0	542,721	201,857	18.44
Final	**3,997,579**	**0**	**542,721**	**199,879**	18.58

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New Jersey

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	18,241,502	446,005		912,075	7.45
Interim Phase 2	17,107,548	0	3,413,100	855,377	24.95
Interim Phase 3	16,681,949	0	3,413,100	834,097	25.46
Final	**16,599,745**	**0**	**3,413,100**	**829,987**	25.56

New Mexico

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	14,789,981	823,049		739,499	10.56
Interim Phase 2	13,514,670	0	627,085	675,734	9.64
Interim Phase 3	12,805,266	0	627,085	640,263	9.90
Final	**12,412,602**	**0**	**627,085**	**620,630**	10.05

New York

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	35,493,488	557,771		1,774,674	6.57
Interim Phase 2	32,932,763	0	3,815,381	1,646,638	16.59
Interim Phase 3	31,741,940	0	3,815,381	1,587,097	17.02
Final	**31,257,429**	**0**	**3,815,381**	**1,562,871**	17.21

North Carolina

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	60,985,831	2,674,590		3,048,792	9.38
Interim Phase 2	55,749,239	0	2,120,178	2,787,462	8.80
Interim Phase 3	52,856,495	0	2,120,178	2,642,825	9.01
Final	**51,266,234**	**0**	**2,120,178**	**2,563,312**	9.14

North Dakota

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	25,453,173	2,150,635		1,272,659	13.45
Interim Phase 2	23,095,610	0	-	1,154,781	5.00
Interim Phase 3	21,708,108	0	-	1,085,405	5.00
Final	**20,883,232**	**0**	-	**1,044,162**	5.00

Ohio

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	88,512,313	4,788,372		4,425,616	10.41
Interim Phase 2	80,704,944	0	1,757,326	4,035,247	7.18
Interim Phase 3	76,280,168	0	1,757,326	3,814,008	7.30
Final	**73,769,806**	**0**	**1,757,326**	**3,688,490**	7.38

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Oklahoma

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	47,577,611	2,067,006		2,378,881	9.34
Interim Phase 2	43,665,021	0	3,121,167	2,183,251	12.15
Interim Phase 3	41,577,379	0	3,121,167	2,078,869	12.51
Final	**40,488,199**	**0**	**3,121,167**	**2,024,410**	12.71

Oregon

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	9,097,720	154,353		454,886	6.70
Interim Phase 2	8,477,658	0	1,291,027	423,883	20.23
Interim Phase 3	8,209,589	0	1,291,027	410,479	20.73
Final	**8,118,654**	**0**	**1,291,027**	**405,933**	20.90

Pennsylvania

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	106,082,757	5,039,346		5,304,138	9.75
Interim Phase 2	97,204,723	0	4,392,931	4,860,236	9.52
Interim Phase 3	92,392,088	0	4,392,931	4,619,604	9.75
Final	**89,822,308**	**0**	**4,392,931**	**4,491,115**	9.89

Rhode Island

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	3,811,632	35,674		190,582	5.94
Interim Phase 2	3,592,937	0	778,307	179,647	26.66
Interim Phase 3	3,522,686	0	778,307	176,134	27.09
Final	**3,522,225**	**0**	**778,307**	**176,111**	27.10

South Carolina

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	31,025,518	1,652,802		1,551,276	10.33
Interim Phase 2	28,336,836	0	1,029,366	1,416,842	8.63
Interim Phase 3	26,834,962	0	1,029,366	1,341,748	8.84
Final	**25,998,968**	**0**	**1,029,366**	**1,299,948**	8.96

South Dakota

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	4,231,184	264,207		211,559	11.24
Interim Phase 2	3,862,401	0	130,831	193,120	8.39
Interim Phase 3	3,655,422	0	130,831	182,771	8.58
Final	**3,539,481**	**0**	**130,831**	**176,974**	8.70

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Tennessee

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	34,118,301	2,178,084		1,705,915	11.38
Interim Phase 2	31,079,178	0	632,949	1,553,959	7.04
Interim Phase 3	29,343,221	0	632,949	1,467,161	7.16
Final	**28,348,396**	**0**	**632,949**	**1,417,420**	7.23

Texas

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	221,613,296	10,400,192		11,080,665	9.69
Interim Phase 2	203,728,060	0	15,990,657	10,186,403	12.85
Interim Phase 3	194,351,330	0	15,990,657	9,717,567	13.23
Final	**189,588,842**	**0**	**15,990,657**	**9,479,442**	13.43

Utah

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	28,479,805	1,401,189		1,423,990	9.92
Interim Phase 2	25,981,970	0	825,586	1,299,099	8.18
Interim Phase 3	24,572,858	0	825,586	1,228,643	8.36
Final	**23,778,193**	**0**	**825,586**	**1,188,910**	8.47

Virginia

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	31,290,209	1,386,546		1,564,510	9.43
Interim Phase 2	28,990,999	0	3,011,811	1,449,550	15.39
Interim Phase 3	27,898,475	0	3,011,811	1,394,923	15.80
Final	**27,433,111**	**0**	**3,011,811**	**1,371,656**	15.98

Washington

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	12,395,697	751,434		619,785	11.06
Interim Phase 2	11,441,137	0	1,383,060	572,057	17.09
Interim Phase 3	10,963,576	0	1,383,060	548,179	17.62
Final	**10,739,172**	**0**	**1,383,060**	**536,959**	17.88

West Virginia

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	62,557,024	3,506,890		3,127,851	10.61
Interim Phase 2	56,762,771	0	-	2,838,139	5.00
Interim Phase 3	53,352,666	0	-	2,667,633	5.00
Final	**51,325,342**	**0**	-	**2,566,267**	5.00

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Wisconsin

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	33,505,657	2,393,870		1,675,283	12.14
Interim Phase 2	30,571,326	0	1,181,175	1,528,566	8.86
Interim Phase 3	28,917,949	0	1,181,175	1,445,897	9.08
Final	**27,986,988**	**0**	**1,181,175**	**1,399,349**	9.22

Wyoming

	Mass Goal	CEIP	Output based Allocaiton	RE Set-Aside	Set-Aside as a % of Mass budget
Interim Phase 1	38,528,498	3,104,324		1,926,425	13.06
Interim Phase 2	34,967,826	0	45,114	1,748,391	5.13
Interim Phase 3	32,875,725	0	45,114	1,643,786	5.14
Final	**31,634,412**	**0**	**45,114**	**1,581,721**	5.14