Existing Source Performance Standards for
Greenhouse Gas Emissions from Electrical Generating Units

Implementation of Section 111(d) for Existing Electric Generating Units

A whitepaper from the Coalition for Innovative Climate Solutions

Pursuant to an executive order of the President, EPA has begun a regulatory process under Section 111(d) of the Clean Air Act to regulate greenhouse gas ("GHG") emissions from existing fossil-fuel electric generating units ("EGUs"). Section 111(d) targets existing sources that would be subject to a standard of performance under Section 111(b) if they were new sources.[1] These sources are referred to herein as "jurisdictional sources." EPA has proposed GHG performance standards for new coal-fired and gas-fired EGUs under Section 111(b), thus triggering the rulemaking process for existing coal-fired and gas-fired EGUs under Section 111(d).

As a first step in this process, Section 111(d) directs EPA to prescribe regulations which shall "establish a procedure" under which each state shall submit a plan that establishes standards of performance for existing sources. Such existing source performance standards must be based on the "best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[2]

The scope of EPA's authority to prescribe the best system of emission reduction ("BSER") and the states' authority in setting performance standards applicable to existing EGUs has been the subject of much debate. This white paper looks beyond defining BSER and setting performance standards applicable to existing coal- and gas-fired EGUs and, instead, focuses on the various measures that the states should be allowed to pursue in their attempts to achieve the GHG emission reductions that may be required. This paper addresses how the states can best implement measures to achieve GHG emissions reductions within their states, both from jurisdictional sources and from measures that are far removed from jurisdictional sources.[3]

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[1] Section 111(d) is triggered only for pollutants for which no national ambient air quality standard applies and which is not subject to regulation under Section 112 or the Clean Air Act. *See* 42 U.S.C. § 7411(d)(1)(A). Carbon dioxide ("CO_2") emissions meet these qualifications.

[2] § 7411(a)(1); (d)(1)(A).

[3] As part of their implementation plans, states must take responsibility for ensuring they can enforce their performance standards. § 7411(d)(1).

RECOMMENDATIONS

To achieve the results envisioned by the President's climate action plan in a positive and cost-effective manner, EPA's guidance should allow states wide latitude in setting standards and in implementing a range of measures to reduce GHG emissions, including:

- EPA's guidance should recognize the early actions taken by numerous states and companies over the past decade or more to address climate change and reduce GHG emissions and should allow credit for retirements of existing coal-fired units.
- EPA's guidance also should allow the states to select the form of the performance standard, i.e., rate-based or mass-based, that best accounts for their unique geographic, resource, and regulatory limitations and opportunities. Further, the guidance should allow a state to adopt any compliance mechanism within its legal authority that helps the state meet its performance standards.
- EPA's guidance should allow states to utilize a wide range of GHG reduction measures, including measures beyond those that can be undertaken at jurisdictional sources, i.e., measures that do not relate to fossil fuel-fired sources.
- EPA's guidance should allow sufficient time for states to develop and approve their implementation plan and incorporate appropriate time for EGU owners and operators to obtain approvals from state public utility commissions, including providing notice and obtaining approvals from independent system operators or electric reliability councils, before moving forward with extremely capital-intensive investments.

IMPLEMENTATION OF PERFORMANCE STANDARDS

This whitepaper does not address BSER or the performance standards that will be applicable to the various fossil fuel-fired EGUs around the country. Rather, it begins with the assumption that EPA's guidance will provide states with sufficiently clear direction that they will be able to develop such standards. Our focus is on implementation issues and, in particular, how the states and the EGU owners should be allowed to achieve GHG emission reductions through measures both at the jurisdictional sources and through alternative, extra-jurisdictional measures to achieve the most cost-effective reductions possible. Below are discussions about key implementation issues along with recommendations on how EPA should address the issues.

A. Credit for Early Action and Baseline Period

It is critically important that EPA recognize and reward states and companies that have taken steps over the past decade and more to address climate change. A program that penalizes states and companies that have shown leadership in reducing GHG emissions would create harmful precedent that will have the long-term effect of discouraging states and companies from implementing beneficial environmental measures unless and until mandated by EPA. Equally important, consumers—the ratepayers and customers—of those companies, along with owners, already are paying for those investments in GHG reductions.

Climate change has been an important environmental focus for many companies and states for years. Companies have included carbon values in integrated resource plans when deciding where and how to invest and have used carbon values in deciding which plants to retain, which to retire, and at which to invest in further pollution controls. Some companies have made public commitments to reduce GHG emissions and carried out those commitments. States and companies have cooperated to promote and enact state legislation to encourage renewable energy development, subsidize home and business energy efficiency and conservation programs, and establish low-carbon resource plans. Some states have entered into compacts to establish carbon trading programs to constrain GHG emissions from power plants. The effect of these prior state and company actions is that their GHG emissions are significantly lower today than they were in 2000 and will continue to decrease over the next several years.

To avoid penalizing these early actions, EPA should give states the ability to choose a baseline period that recognizes the policies and actions that states and companies have taken to reduce GHG emissions. States are in the best position to identify when (1) their climate change programs were implemented and (2) companies within the state began taking actions aimed at reducing GHG emissions. For example, if a state established a 15% renewable portfolio standard in 2004, the state should be allowed to use the reduced carbon intensity that resulted from the renewable energy as part of its Section 111(d) compliance plan and compliance demonstration. Any and all GHG reductions demonstrated by a state, including efficiency upgrades or peak-shaving mandates, repowering projects, biomass co-firing projects, investments in residential conservation, etc., should be counted as part of its compliance with Section 111(d) requirements.

B. Credit Retirement of Existing Power Plants

EPA should allow states to credit retirement of existing coal-fired power plants in meeting their Section 111(d) obligations. Replacement of existing coal-fired plants with lower emitting resources—such as NGCCs, renewable energy, "negawatts" or new Section 111(b)-compliant generation—is one of the most-effective means for reducing GHG emissions in the United States. For example, if a 600 MW, sub-critical, coal-fired EGU were replaced by a Section 111(b)-compliant, 600 MW NGCC, the same electric load could be met with 50% or less of the GHG emissions.[4] If EPA does not give states sufficient flexibility to credit unit retirements, EPA risks creating a perverse incentive for companies to continue operating units that might otherwise be retired.

Recognizing and rewarding coal-plant retirements, and the customers or plant owners who are paying for them, also is important to ensure that companies are able to reasonably plan for meeting future demand. As electricity demand is expected to grow nationally, with some regions seeing acute demand increases, many in the electric industry face unprecedented challenges to keep pace with demand and provide reliable electric service. This means better utilizing existing EGUs and building new generation, including traditional and renewable sources, central power station facilities, and distributed generation. It will require construction of new transmission and distribution systems and upgrading of existing systems. Encouraging this transition in an economically beneficial way will allow companies to focus their resources on critical infrastructure decisions and resource plans.

For past retirements, allowing states to set a reasonable baseline that pre-dates the retirements would allow states to rely on the emission reductions resulting from such retirements. For future retirements, states using a state-wide rate-based performance standard should be allowed to retain the assumed generation from the retired units as part of their demonstration of a rate-based standard. That is, the demonstration of a lb/MWh standard would be based on emissions divided by the MWh generation that includes the retired units' generation prior to retirement. For states that elect to establish a mass-based standard (i.e., annual tonnage limitation), the reduced emissions should automatically be reflected in post-retirement aggregate emissions.

[4] This would be the case whether the NGCC is a greenfield plant or a repowering project that takes advantage of the boiler and/or balance of plant at the existing coal plant location. Similar, but less dramatic, emission reductions result even if the replacement power comes from other, more efficient existing EGUs.

C. Ensure Reasonable State Plan Deadlines

The deadline for state plan submissions should be extended beyond the one year envisioned by EPA.[5] It will be impossible for the states, within one year, to develop, approve, and submit to EPA plans for establishing performance standards and implementation pathways that will achieve the GHG emissions reductions envisioned by EPA. States will need sufficient time to, first, identify the opportunities for emissions reductions within the state and, second, establish and implement the programs necessary to achieve those reductions. If multi-state compacts are pursued, that will require additional time as well.

State legislatures and state agencies may create broad programs that can achieve greater emissions reductions than could be attained on a source-by-source basis, such as renewable portfolio standards and incentives for investments in residential, commercial, and industrial energy efficiency measures. Such a broad approach necessarily will require additional time to ensure a thorough analysis of emissions reductions opportunities.

Once the states have identified their emissions reductions opportunities and developed an approach for translating these opportunities into emissions reductions goals, they will need sufficient time to establish the legal and regulatory framework to attain those goals. The swiftness of state action will be limited by state administrative procedures for implementing new regulations. Indeed, for some states the statutorily required process for a new rulemaking takes more than a year from the date of first proposal because of special review boards or legislative review processes.[6] Further, state environmental agencies that seek to employ a

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[5] EPA's regulations provide that state plans must be submitted nine months after EPA's final guidelines are published, *unless other otherwise specified in the applicable subpart*. 40 C.F.R. § 60.23(a) (emphasis added). EPA has otherwise specified longer deadlines in its revisions to subparts pursuant to Section 111(d). *See, e.g.*, *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units* [the Clean Air Mercury Rule], 70 Fed. Reg. 28,606, 28,649 (May 18, 2005) (allowing 18 months for submittal of state plans). Further, as EPA has previously noted, the Agency has the authority under § 60.23(a)(1) to extend the deadline for state plan submittals. *See* Response to Significant Public Comments Received in Response to: *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil- Fired Electric Utility Steam Generating Units from the Section 112(c) List: Reconsideration* and *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units: Reconsideration* 209 (May 31, 2006).

[6] For example, after the New Mexico Environment Department completes the lengthy notice-and-comment rulemaking process to develop a new state implementation plan ("SIP"), the SIP must be approved by the Environmental Improvement Board ("EIB"). This approval process, which includes an application for a hearing, public notice, public comment, and a hearing, takes approximately four months. This process could take longer, depending upon the EIB's calendar and the number and complexity of issues. In addition, this does not assure

broad implementation program that will obtain emissions reductions through extra-jurisdictional programs will need additional time to coordinate with their state public utility commission, energy agencies, and state legislatures, and to pass any necessary legislation authorizing the planned emissions reduction programs.

States should have the flexibility to determine the options available to achieve compliance, including facility-specific, statewide or regional mechanisms. Establishing interstate or regional market-based emissions reductions programs in areas where there are currently no such mechanisms may be the best option for some states, but will require significant time to ensure proper design and implement such programs.

For all of the foregoing reasons, one year is simply not sufficient for states to develop plans under a rule with such significant impacts. In the event that EPA imposes a one-year deadline for state plans, it should allow for the first submittal to be preliminary in nature.[7]

D. Ensure Reasonable Length of Implementation and Compliance Periods

EPA's Section 111(d) requirements for GHGs will be among the most complex and, potentially, most expensive rules in the Agency's history. After the performance standards are established, it will be critical to give states and companies sufficient time to develop and implement comprehensive compliance programs.

There are thousands of jurisdictional sources in the United States, all of which vary in their generation design, efficiency, operational characteristics, fuel type, access to alternative fuels, ability to accept or burn alternative fuels, ability to install turbine upgrades, unit age, and remaining useful life. Additionally, each state will have different access to renewable energy resources and different abilities to stimulate renewable energy development. The states also have widely varying economies and demographic profiles; as a result, they will have different abilities to establish and successfully implement end-use energy efficiency programs. States will need time to develop an approach to account for these many factors in their compliance programs.

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approval of the SIP. The EIB may decide to approve, disapprove or send the SIP back to the Environment Department for changes. A one-year timeline does not include time to develop and draft a new state plan.

[7] Section 111(d) requires that EPA "prescribe regulations which shall establish a procedure *similar* to that provided by section 7410." (emphasis added). It does not mandate procedures identical to those under Section 110, which require submittal of SIPs. Thus, there is no requirement in the Clean Air Act that the first submittal be a fully developed implementation plan; EPA has the authority to require a more preliminary initial submittal.

It will take EGU owners and operators numerous years to undertake required engineering analyses, develop appropriate resource plans, obtain regulatory and financial approvals, and begin testing of and then implementing many emissions reductions measures. The electric industry is the most capital-intensive industry in the country; construction and utilization decisions cannot be made or implemented on a short time frame. For example, once a resource plan is finalized, it typically takes four to five years to build a new gas-fired combined cycle plant. The required steps include obtaining regulatory approvals to site the new plant; procuring land and electric or gas transmission right-of-ways; seeking and procuring preconstruction permits; entering required engineering, procurement and construction contracts; and actual construction of the plant. Testing is then required to ensure that the plant meets the actual specifications and emission rates provided for in the construction contracts; sometimes, additional modifications are required, which, with requisite engineering and construction, can take months or even longer. Section 111(d) implementation could involve altering the fuel source for existing power plants, developing new wind and solar generating facilities, constructing natural gas pipelines, repowering or retiring existing coal-fired power plants, developing and implementing new retail conservation programs, building new transmission capacity, and many other measures. None of these can be implemented quickly.

Additionally, many of the measures that will generate significant emission reductions will, in any given year, be more or less effective, prompting the need for a multi-year compliance period. This is especially true in states such as Pennsylvania and Ohio, which are part of a multi-state region controlled by an independent system operator (PJM). Generation by specific units in each state is driven by a need to ensure reliability for the multi-state region and is based on system demand, energy prices, and bid prices; neither the generators nor the states have control over which units are dispatched. Extra-jurisdictional measures, such as renewable energy supplies, energy conservation programs, and end-use energy efficiency measures further complicate the picture for these states and introduce a level of uncertainty in other states. Even the best-laid GHG plans can be upset by unpredictable and uncontrollable forces, such as weather, forced outages at, or retirements of, nuclear plants, fuel supply disruptions, and fuel price variability. As EPA has noted in previous rulemakings, and as recently illustrated by extreme weather events in early 2014, an EGU's operations (and, consequently, its GHG emissions) will vary greatly over the course of any given year. "A cold winter or hot summer will result in high levels of 'normal' operations while a relatively mild year will produce lower 'normal' operations . . . . [E]lectricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant."[8]

To address these concerns, EPA should direct the states to allow several years before the start of any compliance period. At the earliest, the compliance period should begin no sooner than three years after a state plan is approved by EPA. Further, the compliance period should be at least five to ten years in length to address the natural variability in the demand for electricity, and should allow the states to phase in requirements over time.

E. Allow Use of Mass-Based or Rate-Based Standards

One of the most important flexibility measures for the states will be the form of the performance standard that they elect to use for their Section 111(d) plans. The form of the performance standard will largely determine which compliance options[9] will be available to the states and companies to achieve broad-based GHG reductions.

EPA has traditionally called for Section 111(d) standards to be based on rate-based standards, i.e., lb/MMBtu. In this instance, states should be given the flexibility to establish an average rate-based standard (in lbs/MWh applicable to each jurisdictional EGU) or a mass-based standard derived from the rate-based performance standards. Some states will prefer to employ a rate-based approach for various reasons, while other states may prefer to establish a state-wide tonnage emission cap applicable to all jurisdictional sources to better reflect the emission reduction benefits of both plant-specific and non-EGU emissions reduction measures.

EPA has often used rate-based standards to implement rules, including the recently proposed GHG performance standards for new EGUs, so rate-based standards are familiar to both sources and regulators. They also offer flexibility in state compliance mechanisms. For example, identifying specific emission rates associated with meeting Section 111(d) standards could help facilitate multi-state compliance.[10] Once each state has established emission rates

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[8] *Requirements for Preparation, Adoption and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans; Standards of Performance for New Stationary Sources*, 57 Fed. Reg. 32314, 32325 (Jul. 21, 1992).

[9] These options include, but are not limited to, renewable portfolio standards, demand-side management, nuclear uprates, end-use energy efficiency measures, home insulation investments, upgrades to transmission and distribution systems, and development of distributed and centralized renewable energy resources. States should have discretion to capitalize on whatever mechanisms have the greatest potential for cost-effective emissions reductions given their geographic and regional limitations.

[10] We recognize that states may need to enter into agreements to ensure that each state will recognize emission reductions from other states.

for existing jurisdictional sources, state plans could establish a system for these sources to average their performance to demonstrate compliance with the emission rates on a fleet-wide or state-wide basis. This would incentivize more cost-effective investments and emissions reductions. Unit-specific emission rates also could allow EGU owners and operators to achieve compliance though emissions rate averaging. This may be particularly appealing in states with rapidly growing electricity demand, where setting a mass-based emissions cap on existing sources is difficult.

Allowing states to go beyond the rate-based standard to employ a mass-based approach would open the door to a number of innovative market-based approaches that states could implement to satisfy their Section 111(d) obligations in a least-cost manner. For example, a mass-based approach could make it easier for states to allow sources operating pursuant to an independent system operator ("ISO") to achieve compliance on an ISO-wide, regional basis. The states would determine the emission reductions needed from the ISO sources and provide that information to the ISO. If all states participate, the ISO could aggregate the emission reductions and determine the best sequence of dispatch for all units in the ISO to achieve the reductions at the least cost while also maintaining system reliability.[11] A mass-based approach also is likely to be more straightforward than a rate-based approach when states seek to show that their various compliance mechanisms—such as renewable energy, energy efficiency, crediting of plant retirements, and repowering—have achieved the targeted reductions for a given compliance period.

Because each state is uniquely situated with respect to its geographic, resource, and regulatory characteristics, states should be allowed to select the form of the standard that allows them to best capitalize on their opportunities to meet their emission reduction obligations.

CONCLUSION

The CICS encourages EPA to develop its regulations and guidance for the Section 111(d) program for EGUs in a manner that is legally, politically and economically sustainable. That means establishing guidance for BSER that is based on emission reductions that are achievable from jurisdictional sources—those that would be subject to Section 111(b) if they were built new. It also means, most importantly, allowing the states and EGU companies to achieve GHG emissions reductions in the most robust, cost-effective manner possible. EPA regulations and guidance should allow the states to determine an appropriate base line period from which to measure emission reductions, account for early actions, give companies a long enough

[11] CICS does not intend here to endorse an ISO-wide approach but supports allowing states the flexibility to engage in the creation of such a system, as that concept continues to develop.

compliance period to address uncontrollable events, allow companies to generate GHG emission reductions through actions unrelated to the jurisdictional EGUs, and reward companies that are able to permanently retire existing EGUs.

About the Coalition for Innovative Climate Solutions

The Coalition for Innovative Climate Solutions is a group of forward-thinking electric generating companies and electric service providers located across the country. CICS members reflect our nation's diverse geography with widely varying energy resources, state regulatory frameworks, and electricity market conditions. Our members span 19 states, and represent a significant portion of the nation's electricity industry. CICS members include Entergy, Great River Energy, Portland General Electric Company, PPL Corporation (including its affiliates LG&E and KU), Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, and Xcel Energy.