Discussion Background Paper:  
Best System of Emission Reduction (BSER)

Relevant Statutory and Regulatory Text

CAA Section 111(d) directs EPA to “prescribe regulations which shall establish a procedure similar to that provided by section 110” for the States to submit to EPA “a plan which [] establishes standards of performance” and “provides for the implementation and enforcement of such standards of performance” for existing sources of an air pollutant once EPA has established a standard of performance for new sources of that pollutant.\(^1\) 42 U.S.C. § 7411(d).

CAA Section 111(a)(1) defines “standard of performance” as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of 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.


EPA’s CAA Section 111(d) implementing regulations call for EPA to publish draft and final guideline documents that provide information about the control of the designated pollutant from the designated sources to inform the development of State plans. These EPA regulations define an “emission guideline” as a guideline, “which reflects the degree of emission reduction achievable through the application of the **best system of emission reduction** which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.” 40 C.F.R. § 60.21(e) (emphasis added).

The regulations list, among the information that EPA will provide to the States, “[a]n emission guideline that reflects the application of the **best system of emission reduction** (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved.” Id. § 60.22(b)(5) (emphasis added).

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\(^1\) This description glosses over an important debate regarding the relationship between sections 111(d) and 112. There is an acknowledged potential conflict in the text of the Clean Air Act as a result of competing House and Senate versions of Section 111(d) contained in the Clean Air Act Amendments of 1990. The House version would bar regulation of any **source category** already regulated under Section 112, while the Senate version focuses instead on whether EPA has already listed a **pollutant** under Section 112(b). EPA attempted to address this conflict in its 2005 Clean Air Mercury Rule by applying the bar only to pollutants regulated under 112, but the conflict has yet to be considered by the courts. With respect to these Section 111(d) guidelines, EPA also appears to be proceeding as if the statutory bar only applies to pollutants regulated under Section 112. This issue is expected be resolved by the courts, but not likely until after EPA finalizes its Section 111(d) guidelines.
Options for BSER in EPA Guidelines

The question of what types of reductions can be considered within EPA’s BSER determination and in what form EPA can identify such reductions as guidelines for the States is relatively untested under the statute. Stakeholder dialogue up to this point has identified three primary options: a source-based BSER approach, a system-based BSER approach, or a hybrid approach. An explanation of each approach follows.

Source-Based BSER Approach

A source-based BSER approach would only mandate reductions based upon actions that can be taken directly by and at the regulated source. In other words, a source-based BSER approach would be restricted to reductions available within the source’s control and within the fence line of the facility.

EPA has highlighted as examples of potential supply-side actions within a source-based BSER, heat rate improvements or energy efficiency upgrades at the source, fuel switching to a lower-emitting fuel at the source, or co-firing with a lower-emitting fuel at the source.

The source-based BSER approach has the potential to provide some degree of legal certainty because a source-based BSER is consistent with EPA’s previous regulation of stationary sources under the CAA.

However, if EPA were to establish BSER based on fuel switching to, or co-firing of, a lower-emitting fuel or the adoption of carbon capture and sequestration (CCS) at the source, this would introduce legal uncertainty to the source-based approach because taking these actions into account in determining BSER would essentially redefine the source. While this issue has not been addressed in the Section 111 context, in the context of an analogous EPA CAA regulatory program, EPA has expressly recognized that the statute probably does not allow it to redefine the source. In EPA’s “PSD and Title V Permitting Guidance for Greenhouse Gases,” EPA acknowledged that while its evaluation of Best Available Control Technology (BACT) in Prevention of Significant Deterioration (PSD) permitting is designed to evaluate a broad selection of pollution control options, it “need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.” 26 (Mar. 2011) (citing In re Prairie State Generating Company, 13 E.A.D. 1, 23 (EAB 2006)). EPA explained that “BACT should generally not be applied to regulate the applicant’s purpose or objective for the proposed facility.” Id. Having recently decided not to redefine the source for new and modified sources in the PSD context in its BACT guidance, it would be inconsistent for EPA now to decide to establish BSER for existing sources under Section 111 in a way that redefines the source.

While a source-based BSER approach that relies upon heat rate improvements alone provides greater legal certainty, it would likely reflect a modest reduction in CO₂ emissions. Some have suggested, for example, that the upper bound of these average on-site efficiency improvements
is likely around 5%. And even this level of reduction may not be achievable, since many sources, including many newer, very efficient electric generating units, may have no actions available to further increase efficiency at all. Thus, total potential emissions reductions through a source-based BSER approach that relies upon heat rate improvements alone would likely be limited.

**System-Based BSER Approach**

A system-based BSER approach would mandate reductions based upon actions that are taken both at and outside the regulated source, including actions taken beyond the regulated source that indirectly reduce emissions at the source. In other words, a system-based BSER approach would include indirect emission reductions derived from reducing the overall end use of electricity in homes and businesses that receive power from the interconnected power grid.

Examples of a potential system-based BSER include requiring demand-side measures, such as consumers installing or using more energy-efficient appliances, heating, lighting and air conditioning, as well as other measures outside the control of the generating unit, such as improvements in the transmission of electricity, dispatch changes beyond those resulting from market forces, and increased generation from renewable sources.

A system-based BSER approach could achieve greater CO₂ emission reductions from mandating offsite measures and measures beyond a source’s control. Some of those measures may be relatively inexpensive and some would be immediate.

However, a system-based BSER approach that mandates reductions based on actions outside the control of the regulated source would involve legal uncertainty. There is nothing in the CAA that authorizes EPA to issue guidelines that require a standard to be based on something that is outside the fence and outside the control of the source. It is also unprecedented—EPA, in stationary source regulation, has always limited its standard setting (mandatory requirements) to the inventory of control opportunities or work practice opportunities that reside at the source and over which the source has control.

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2 See, e.g., Burtraw, Dallas and Woerman, Matt, “Technology Flexibility and Stringency for Greenhouse Gas Regulations,” Resources for the Future Discussion Paper (RFF DP 13-24, July 2013)(noting at pages 6-7 that “[t]he engineering literature suggests there are varying opportunities for efficiency improvements that could achieve a 4 to 5 percent improvement on average across the population of coal plants.”). It will be very important for EPA to do its own empirical analysis to determine the actual current opportunities for efficiency improvements—particularly since many of the upgrades projected in existing studies have either already occurred or may not be available. In doing so, EPA should be mindful of the fact that generating assets vary widely from state to state.

3 Many have commented that for EPA to mandate reductions based on actions outside the control of the regulated source (e.g., at the customer level) would be comparable to EPA requiring a car manufacturer or refiner to reduce vehicle miles traveled.
Although the scope of EPA’s reach into the energy system is relatively untested, many believe that EPA lacks the authority\textsuperscript{4} to mandate State or source action beyond the source. Many States have implemented very successful demand-side management and renewable generation programs, but most of those programs have been enacted at the state level by state legislatures and by agencies, such as state public utility commissions, that are constitutional entities under state law.

**Hybrid BSER Approach**

In a hybrid BSER approach, EPA would differentiate between those reductions it can *mandate* through setting minimum performance standards and those it can *recognize and encourage* through one or more voluntary measures. Under a hybrid approach, EPA’s Section 111(d) guidelines would mandate only those reductions that are available on site at a generating unit and that do not redefine the source. However, EPA could also establish separate protocols to identify and appropriately credit direct and indirect energy-sector CO\textsubscript{2} emission reductions that States, third parties and regulated sources achieve by other means and that EPA can verify through appropriate quantification techniques. While there is an element of legal uncertainty with this approach, since EPA may not be able to connect offsite reductions to particular regulated units, there is still a strong basis for EPA to credit the reductions because they would occur at one or more units within the regulated source category.

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\textsuperscript{4} See, e.g., Section 808 of the Clean Air Act, which directs EPA and the Federal Energy Regulatory Commission (FERC) to study the net environmental benefits of renewable energy, but directs FERC to transmit the study to Congress for further Congressional action rather than authorizing independent EPA regulatory action.
Discussion Background Paper:  
Form of Performance Standard

Relevant Statutory and Regulatory Text

CAA 111(d) directs EPA to “prescribe regulations which shall establish a procedure similar to that provided by section 110” for the States to submit to EPA “a plan which [] establishes standards of performance” and “provides for the implementation and enforcement of such standards of performance” for existing sources of an air pollutant once EPA has established a standard of performance for new sources of that pollutant. 42 U.S.C. § 7411(d).

CAA Section 111(a)(1) defines “standard of performance” as “a standard for emissions of air pollutants. . . .” 42 U.S.C. § 7411(a)(1). EPA’s CAA Section 111(d) implementing regulations define “emissions standard” as “a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.” 40 C.F.R. § 60.21(f). The regulations further specify, with respect to the requirements for State plans, that “[e]mission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable.” 40 C.F.R. § 60.24(b)(1). The regulations provide that EPA will determine, in its guideline documents, the cases in which establishing emissions standards through allowable rates of emission or allowances are impracticable. See id.¹

Options for the Form of the Performance Standard in EPA Guidelines

There are several ways that EPA could frame the form of the minimum performance expectations in its guidelines. EPA could adopt in its guidelines: (1) a rate-based carbon intensity standard (e.g., pounds per megawatt-hour) and could either require the rate to be measured exclusively at a single source or allow it to be averaged across multiple sources; (2) a mass-based standard that caps the total tons of CO₂ emitted in the sector over some selected period of time; or (3) a reduction-based standard that requires a certain degree of CO₂ emissions reduction from a selected baseline period. An explanation of each approach follows.

Rate-Based Carbon Intensity Approach

A rate-based approach would express minimum performance expectations in the form of an emissions rate or carbon intensity per unit of production for the source category averaged over some period of time. For example, a rate-based standard could be expressed as pounds of CO₂ per megawatt hour for electric generating units.

¹ While the CAA allows EPA to promulgate “a design, equipment, work practice, or operational standard” where the Administrator finds “it is not feasible to prescribe or enforce a standard of performance,” 42 U.S.C. § 7411(h)(1), this authority is limited to where “the Administrator determines that (A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations,” id. § 7411(h)(2).
This approach avoids legal risk as it is expressly provided for in the Section 111(d) implementing regulations and EPA has previously promulgated a number of rate-based emission standards. As noted above, the regulations provide for an emissions standard “setting forth an allowable rate of emissions into the atmosphere.” 40 C.F.R. § 60.21(f). EPA has considerable experience with rate-based programs, which it has used to remove lead from gasoline and to reduce emissions from various categories of mobile sources. See, e.g., EPA, Regulation of Fuel and Fuel Additives; Gasoline Lead Content; Final rule, 50 Fed. Reg. 9,386 (Mar. 7, 1985; implementing the final segment of a lead phase-out program that EPA launched in 1973); EPA, Final Rule for New Gasoline Spark-Ignition Marine Engines, 61 Fed. Reg. 52088 (Oct. 4, 1996); Final Rule, NHTSA, Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011; Final Rule, 74 Fed. Reg. 14196 (Mar. 30, 2009); EPA and NHTSA, 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule, 77 Fed. Reg. 62624 (Oct. 15, 2012). As another recent example, EPA’s newly proposed CO2 New Source Performance Standards for new power plants adopt a rate-based expression of the performance standard. See EPA, “Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units,” 88 (Sept. 20, 2013) (prepublication version).

A rate-based standard accommodates fluctuations in the quantity of fossil energy generated over any given period. A rate-based standard also avoids significant practical and political risks that stem from the difficult and potentially controversial task of allocating allowances among the States. However, a rate-based approach does not guarantee an exact quantity of CO2 reductions, since it does not limit the total CO2 emitted from the regulated sector.

**Averaging**

If EPA adopted a rate-based standard in its guidelines, performance could be measured at a single source or could be demonstrated by averaging performance across multiple sources.

A source-specific performance standard would raise certain practical challenges to compliance, given source diversity in this sector. Some electric generating units, including many newer, very efficient ones, would have few, if any, opportunities to reduce CO2 emissions. Thus, these sources may be unable to comply with a source-specific rate-based performance standard.

Allowing regulated entities to average performance across multiple sources has the practical benefit of providing flexibility to accommodate existing source diversity. If a regulated entity could average the performance of its very efficient units with other covered units in its fleet or in the marketplace, this would solve the problem of variation among unit performance and efficiency opportunities. There is also ample precedent for such an approach—EPA has previously allowed averaging (as well as banking and trading) in its rate-based programs. See, e.g., EPA, Regulation of Fuel and Fuel Additives; Final Rule, 47 Fed. Reg. 49322 (Oct. 29, 1982); EPA, Regulation of Fuels and Fuel Additives; Banking of Lead Rights; Final rule, 50 Fed. Reg. 13,118 (Apr. 1, 1985); EPA, Final Rule for New Gasoline Spark-Ignition Marine Engines, 61 Fed. Reg. 52088 (Oct. 4, 1996); EPA, Control of Air Pollution From New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements; Final Rule, 65 Fed. Reg. 6,698 (Feb. 10, 2000) (“Today’s action also introduces an averaging, banking, and trading program to provide flexibility for refiners and ease implementation of the

Mass-Based Approach

A mass-based approach would express minimum performance expectations in the form of a total cap on tons of CO₂ emitted in the sector over some period of time. EPA initially adopted a mass-based standard with allowance trading under Section 111(d) for its Mercury Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, or Clean Air Mercury Rule. See 70 Fed. Reg. 28606 (May 18, 2005); although this standard was overturned.²

A mass-based approach is designed to provide certainty regarding the amount of CO₂ that is emitted by the regulated sector within each state. Current EPA Section 111(d) regulations appear to leave open this option for appropriate circumstances. However, some argue that EPA lacks any legal or other basis on which to set mandatory State CO₂ budgets. Unlike ozone attainment and other criteria pollutant challenges, for which air quality modeling and air quality control region characteristics can determine a region’s attainment-based carrying capacity, there appear to be no environmental criteria to guide EPA in setting State greenhouse gas budgets. While EPA could use historical emissions, power sector greenhouse gas emissions have varied significantly over time due to shifts in electricity generation due to lower natural gas prices, regional energy strategies and other key considerations. And setting State budgets would risk creating winners and losers for reasons other than market conditions. Under this view, the States could elect to demonstrate State program equivalency with EPA’s Section 111(d) guidelines by using an allowance-based approach (e.g., cap and trade), but EPA could not mandate that State EGU emissions meet a particular mass-based limit.

Percent Reduction or Progress-Based Approach

A percent reduction or progress-based approach would express minimum performance expectations in the form of a specified minimum degree of CO₂ emission reductions by a State or source relative to a chosen baseline period. Such an approach would be designed to ensure a total degree of CO₂ emission reductions over the chosen historic level.

EPA does not appear to have previously taken a percent reduction or purely progress-based approach in setting source category performance standards. There is some precedent, however, for setting overall progress requirements for air quality control regions under the Act. Sections 171 and 172 of the Act provide, for example, that State nonattainment plans provide for reasonable further progress, which requires “annual incremental reductions in emissions.”

² This prior Section 111(d) mercury standard was invalidated by the D.C. Circuit on other grounds related to EPA’s delisting of coal- and oil-fired EGUs from the list of sources whose emissions are regulated under Section 112 of the CAA, which regulates hazardous air pollutants. See New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).
If EPA selected a reductions-based standard of performance, the determination of the baseline year and tying the degree of reduction to the BSER would present political and practical challenges. A number of the States have undertaken CO₂ emission reduction activities in recent years, and these States would want the selected baseline to provide credit for these reductions in measuring performance. Selecting the appropriate degree of reduction would also be challenging, as there would seem to be no necessary environmental or economic benchmark to guide that selection. Finally, as in the case of a mass-based emission standard, a reduction-based standard could arguably fail to account for regional fluctuations in fossil energy generation due to conditions unrelated to environmental performance.

One potential approach worth considering is the use of a progress benchmark as a proxy for State equivalency when EPA determines that for a state to achieve such progress it must necessarily have achieved the type and amount of reductions that EPA ultimately mandates in its Section 111(d) guidelines. Under such circumstances, as outlined in a separate background paper regarding State equivalency, EPA may be able to use a progress demonstration to approve a State plan without undergoing time-consuming and costly analysis.
EPA’s current CAA Section 111(d) implementing regulations list certain requirements that State plans must meet. Among the requirements of these regulations, State plans must “include emission standards and compliance schedules” and the emission standards “shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable.” 40 C.F.R. §§ 60.24(a), (b)(1). State plans must specify “[t]est methods and procedures for determining compliance with the emission standards,” id. § 60.24(b)(2), and the “[e]mission standards shall apply to all designated facilities within the State,” id. § 60.24(b)(3). A State plan “shall include an inventory of all designated facilities, including emission data for the designated pollutants,” and “emission rates of designated pollutants from designated facilities shall be correlated with applicable emission standards.” Id. § 60.25(a). “Correlated” means “presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable emission standards.” Id. A State plan must also provide for monitoring compliance, which includes recordkeeping and reporting requirements for owners and operators of covered sources, periodic inspection of covered facilities, and submission of State progress reports. Id. §§ 60.25(b), (c). Finally, State plans must demonstrate that the State has legal authority to carry out and enforce the plan. Id. § 60.26.

EPA’s regulations also require that where EPA has made a determination that the “designated pollutant may cause or contribute to endangerment of public health, [State] emission standards shall be no less stringent than the corresponding [EPA] emission guideline(s). . . .” Id. § 60.24(c) (emphasis added). However, the regulations authorize states to adopt a less stringent standard on a “case-by-case” basis for particular facilities or classes of facilities, where the state can demonstrate: “(1) Unreasonable cost of control resulting from plant age, location, or basic process design; (2) Physical impossibility of installing necessary control equipment; or (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard . . . more reasonable.” Id. § 60.24(f). The regulations clarify that they should not be “construed to preclude any State or political subdivision thereof from adopting or enforcing [] emission standards more stringent than [EPA’s] emission guidelines.” Id. § 60.24(g).

Options for Measuring State Performance and Determining Equivalency

EPA’s regulations currently require States, at a minimum, to demonstrate legal authority to carry out and enforce a plan and to comply with the minimum monitoring, inventory, and reporting requirements, outlined above. States also must demonstrate that their programs meet the minimum required stringency as provided in EPA’s guidelines. If EPA develops a model state rule, then certainly timely and effective State implementation of that rule would be deemed compliant. Commenters have identified the following alternative methods by which a State may be able to demonstrate that its program is equivalent or more stringent than EPA’s guidelines: (1) that sources within their jurisdiction meet the prescribed emissions performance in the manner designated by EPA (e.g., rate-based), (2) that the State program achieves comparable
emissions or emission reductions as anticipated by the EPA guidelines (mass-based), (3) that the State program achieves the progress required by EPA’s guidelines (percent reduction-based), or (4) that the State program reflects a degree of stringency through other indicators (e.g., market price in a State or regional cap and trade program) that is equivalent to or more stringent than required by EPA’s guidelines (e.g., price-based). EPA would be expected to promulgate guidance for such equivalency demonstration methods. These methods are described below.

- **Rate-Based Carbon Intensity Equivalency:** A rate-based equivalency would demonstrate that the State program achieves a carbon intensity for the regulated sector that is either equivalent to or better than the carbon intensity of EPA’s Section 111(d) emission guidelines.

- **Mass-Based Equivalency:** A mass-based equivalency would demonstrate that the State program achieves an equal or greater total CO₂ emissions or emission reductions relative to what would be achieved by the approach outlined in EPA’s Section 111(d) emission guidelines.

- **Percent Reduction-Based Equivalency:** A percent reduction-based equivalency would demonstrate that the State program achieves an equal or greater degree of CO₂ emission reductions over a selected baseline relative to the degree of emission reductions that would be achieved by the approach outlined in EPA’s Section 111(d) emission guidelines.

- **Market Price-Based Equivalency:** A market price-based equivalency would demonstrate that the State program reflects a carbon price, through a cap and trade program, carbon tax, or other approach, that is comparable to or above the cost-effectiveness benchmark used by EPA in establishing the minimum performance expectations for the regulated sector in its Section 111(d) emission guidelines.

What methods a State may use to demonstrate that its program is equivalent or more stringent than EPA’s guidelines is untested as a legal matter. There are a number of questions regarding the measurement of State performance and implementation of equivalency demonstrations that would be relevant to any of these approaches:

*How would the measurement of State equivalency take into account the State’s ability to make case-by-case demonstration for a particular facility or class of facilities to support the application of less stringent emission standards for these facilities?* Although State emission standards must generally be “no less stringent” than EPA’s corresponding emissions guidelines, EPA’s Section 111(d) implementing regulations provide the States an option to adopt less stringent standards for a particular facility or class of facilities if certain factors are demonstrated. This will be an important consideration when crafting State equivalency methodologies.
If EPA’s emissions guidelines adopt a particular form of performance standard (i.e. rate-based, mass-based, percent reduction-based) will EPA be able to develop effective methodology to evaluate State performance under all of the potential methods of equivalency? Theoretically, methods could be developed to compare EPA’s emission guideline under each of these metrics. However, there will likely be significant discourse regarding the inputs to and assumptions of any methodologies.

How will the measurement of State performance and equivalency take into account a State program that allows offsets outside of the regulated sector? It is unclear how (or whether) the measurement of State performance and equivalency with EPA’s Section 111(d) guidelines would take into account State cap-and-trade programs that permit offsets outside of the electricity sector. EPA has suggested that, for the purposes of Section 111(d), the statute may constrain EPA to determine that emissions reductions are happening at the covered source category. However, EPA has indicated a strong interest in understanding the views of California and other States on this point.

Does each of these potential methods of measuring State performance or equivalency fall within the definition of “emissions standards” in EPA’s Section 111(d) implementing regulations? It is unclear whether each of these methods would be deemed “emission standards” under EPA’s definition. However, EPA’s definition incorporates both rates of emission and allowance systems, suggesting considerable discretion in what methods of measuring State performance would be encompassed within that term. There is also potential for EPA to revise the regulatory definition of “emission standards,” as it did in adding “allowance system” to the definition in conjunction with its Mercury Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, or Clean Air Mercury Rule. See 70 Fed. Reg. 28606, 28649 (May 18, 2005).

Does each of these potential methods of measuring State performance or equivalency facilitate compliance with State plan requirements, such as the designated facility inventory that could require correlation between emission rates for designated facilities and the emissions standards? EPA may choose to change its requirements to be more flexible for different State approaches.

Presumptive Equivalency

Many States will be interested in whether EPA can develop an equivalency program that recognizes – up front (i.e., at the outset of EPA’s program) – that the State program complies with the EPA guidelines. If so, then a State may be able to avoid the time delay and cost associated with more granular equivalency demonstrations. It may be that EPA can develop such a “presumptive equivalency” process where certain conditions and benchmarks are met. For example, if a State program reduces energy sector CO₂ emissions by any means (e.g., through generation shifts to less carbon-intensive generation sources, the implementation of demand-side management programs, or otherwise) beyond the minimum expected performance of EPA’s Section 111(d) guidelines, then more detailed analysis may not be warranted. EPA modeling of expected greenhouse gas reductions can provide progress or performance benchmarks by which it can determine that a State program must in fact have achieved the purpose of the guidelines. This approach essentially would recognize that, if a State were
ultimately required to undergo a more formal equivalency demonstration, then it would almost certainly be determined to have met or outperformed the guidelines.

While such an approach presents some legal risk because it is untested and deviates from EPA’s past evaluation of State plans under Sections 110 or 111(d), it is well within the President’s announced strategy for collaborating with State partners. For example, if EPA were to allow credits generated by suitably reviewed and quantified off-system measures to be used for compliance by regulated electric generating units, then a state that could easily demonstrate that it would have sufficient credits for its on-system sources (the electric generating units) to be in compliance could make that demonstration to EPA rather than actually setting up a program to allocate the credits. EPA can insulate its overall Section 111(d) program from any legal risk associated with a presumptive equivalency approach if it independently promulgates that option or otherwise structures it as a severable component.

1 Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards, §1(b) (June 25, 2013) (directing EPA to “build on State efforts to move toward a cleaner power sector” in developing emission guidelines under Section 111(d)).
Discussion Background Paper:  
Harmonizing Section 111(d) Requirements with  
Section 111(b) and New Source Review for Modified Sources

A significant program design challenge of Section 111(d) guidelines will be the interaction of  
Section 111(d) with Section 111(b) requirements for modified and reconstructed sources and  
New Source Review (NSR) for modified sources.

Relevant Statutory and Regulatory Background on Section 111(b) For Modified Sources

After EPA determines that a category of stationary sources “causes or contributes significantly  
to, air pollution which may reasonably be anticipated to endanger public health or welfare,”  
CAA Section 111(b) requires EPA to establish standards of performance for new sources within  
that category.  42 U.S.C. § 7411(b)(1).  The CAA defines “new source” in this context to  
include “any stationary source, the construction or modification of which is commenced after  
the publication” of proposed new source standards under Section 111(b) that would be applicable  
to that source.  Id. § 7411(a)(2) (emphasis added).  The statute defines “modification” as “any  
physical change in, or change in the method of operation of, a stationary source which increases  
the amount of any air pollutant emitted by such source or which results in the emission of any air  
pollutant not previously emitted.”  Id. § 7411(a)(4).

The definition of “modification” in EPA’s CAA Section 111(b) implementing regulations is  
nearly identical to the statutory definition, except that it clarifies that the reference to “any air  
pollutant” means “any air pollutant (to which a standard applies).”  40 C.F.R. § 60.2.  The  
regulations separately list certain actions that are expressly excluded from consideration as  
modifications, including:

(1) Maintenance, repair, and replacement which the Administrator  
determines to be routine for a source category. . . .  
(2) An increase in production rate of an existing facility, if that  
increase can be accomplished without a capital expenditure on that  
facility.  
(3) An increase in the hours of operation.  
(4) Use of an alternative fuel or raw material if, prior to the date  
any standard under this part becomes applicable to that source  
type, as provided by § 60.1, the existing facility was designed to  
accommodate that alternative use. . . .  
(5) The addition or use of any system or device whose primary  
function is the reduction of air pollutants, except when an emission  
control system is removed or is replaced by a system which the  
Administrator determines to be less environmentally beneficial.  
(6) The relocation or change in ownership of an existing facility.

Id. § 60.14(e).
The regulations further clarify that “[n]o physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.” Id. § 60.14(h).

EPA regulations also state that the 111(b) standard applies to “[a]n existing facility, upon reconstruction” and this is “irrespective of any change in emission rate.” Id. § 60.15(a). The regulations define “reconstruction” as “the replacement of components of an existing facility to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.” Id. § 60.15(b).

**Considerations for Harmonizing Section 111(d) with Section 111(b) for Modified Sources**

In its recently proposed “Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units,” EPA did not propose standards of performance for modified or reconstructed sources. See EPA, “Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units,” 16 (Sept. 20, 2013) (prepublication version) (hereinafter “Proposed Rule”). This allows an opportunity for EPA to harmonize any potential requirements for modified and reconstructed sources under Section 111(b) with its Section 111(d) guidelines for existing sources.

Such harmonization is important because there is a significant potential for either inconsistent or duplicative regulation between Section 111(d) requirements and Section 111(b) requirements for modified sources, since they would essentially apply to the same sources—existing sources that are modified. Moreover, inconsistent or burdensome “modified unit” standards could truly interfere with Section 111(d) program objectives if they chill opportunities for improving a unit’s efficiency.

Given lack of detail in the statute and the fact that EPA has, up to this point, acted very infrequently under Section 111(d), there should be no obstacle to EPA addressing this issue. While EPA arguably does not have complete discretion, for instance to disregard Section 111(b)’s application to modifications altogether, EPA has wide latitude to harmonize these programs within a reasonable interpretation of the statute. Such an approach would be consistent with Executive Order 13563, which directs agencies to “attempt to promote [] coordination, simplification, and harmonization” to avoid imposing regulatory requirements that are “redundant, inconsistent, or overlapping.” § 3 (Jan. 18, 2011).

When EPA analyzes the performance expectations for existing units, EPA may also consider potential performance expectations for modifications. EPA may likely find that existing and modified sources are limited to the same universe of potential reductions. This is because EPA is likely to find that existing and modified sources are similarly situated with no add-on control opportunity to reduce CO₂ emissions for these sources. While EPA has identified partial carbon capture and sequestration (CCS) as the Best System of Emission Reduction for new coal-fired power plants in its proposed Section 111(b) standards of performance for new sources, see
Proposed Rule at 15-16, EPA has indicated that it does not anticipate determining that CCS has been adequately demonstrated for existing sources. Carbon capture technology is best designed when the unit is initially designed and constructed—rather than as an “add on” control. Furthermore, there is no geographic flexibility for existing sources to exploit for sequestration opportunities, while new sources at least in theory may be able to locate on or near a geologic formation that is suitable for sequestration.

Thus, if EPA evaluates options for modified and reconstructed sources under Section 111(b) and determines that the only reasonably available measures to achieve CO₂ reductions are the same as for existing sources evaluated in the context of Section 111(d), it would be a reasonable interpretation of the statute for EPA to harmonize the requirements. This could be accomplished through a programmatic finding that the Section 111(d) program is just as likely to address modified unit emissions as existing source emissions generally. If an averaging, banking and trading (ABT) program is adopted under Section 111(d), this would further secure such a harmonizing determination because the market price would reward CO₂ reductions at any existing unit, including those that are modified.

Of course, at any future stage, should EPA’s factual record suggest that control determinations (e.g., regarding cost, feasibility and energy impacts) for a modified unit differed materially from those for an existing source, then EPA could at that future time impose appropriate additional requirements on modified units.

**Relevant Statutory and Regulatory Background on NSR for Modified Sources**

NSR requires existing major stationary sources that make major modifications to obtain permits prior to construction. There are two types of NSR permitting for major sources. The Prevention of Significant Deterioration (PSD) requirements apply to major sources making major modifications in attainment areas. See generally, 42 U.S.C. §§ 7470-7479. If the PSD requirements are triggered by a major modification, then installation of Best Available Control Technology (BACT) is required. The nonattainment NSR requirements apply to major sources making major modifications in nonattainment areas. See generally, 42 U.S.C. §§ 7502(c)(5), 7503. If the nonattainment NSR requirements are triggered by a major modification, the lowest achievable emission rate (LAER) must be met and emissions offsets must be obtained. Although nonattainment NSR does not apply to significant net emission increases of greenhouse gases because that program applies only to criteria pollutants (i.e., and not to other “regulated” pollutants such as greenhouse gases), there is risk that power plant modifications pursued to comply with the Section 111(d) program (and thus, e.g., to reduce greenhouse gas emissions by improving unit’s heat rate) could be determined to trigger nonattainment NSR or PSD if that unit’s utilization could increase as its heat rate drops. Such a risk of triggering NSR could well chill the very efficiency improvements that the Section 111(d) program is designed to encourage.

**Considerations for Harmonizing Section 111(d) with NSR for Modified Sources**

As noted above, since the Section 111(d) program may be designed to encourage existing units to reduce their emissions by making on-site efficiency improvements, there is a risk that regulated units will be considered to trigger NSR as they make such modifications. This is
because a more efficient unit will likely be dispatched more and this additional activity could result in a net increase in emissions of one or more pollutants.

One potential way to avoid this issue would be expressly to exempt efficiency improvements undertaken for Section 111(d) compliance from NSR. However, there is significant legal risk in such an approach. The D.C. Circuit struck down EPA’s NSR exemption for pollution control projects, finding that such an exemption exceeded EPA’s statutory authority. See New York v. EPA, 413 F.3d 3, 10-11 (D.C. Cir. 2005).

Another potential approach would be for EPA to develop appropriate alternative screening methods for an expedited, streamlined and less costly NSR process to assure that any criteria pollutant increases resulting from such efficiency improvements do not interfere with attainment. Under such an approach, EPA could establish screening tools to confirm that already well-controlled sources and sources whose “net emissions increases” of criteria pollutants remain below attainment-related significance thresholds are deemed to comply with NSR.

EPA could also determine that compliance with Section 111(d) standards would be deemed to satisfy applicable PSD or BACT requirements for GHG reductions. EPA could make this determination by finding that compliance with the Section 111(d) standards constitutes the “maximum degree of reduction . . . taking into account energy, environmental, and economic impacts and other costs, determine[d]” to be achievable for the permitted units. See 42 USC § 7479(3) (definition of BACT).
A number of stakeholders have argued that relatively inexpensive, near-term CO₂ reductions are available from indirect emission reductions that result, not from controlling a unit’s emissions directly, but from reducing the overall end use of electricity in homes and businesses, and thus indirectly reducing emissions through decreased utilization of electric generation across the interconnected power grid. Therefore, some stakeholders have raised the potential for State end-use energy efficiency (EEE) measures to be compliance options for Section 111(d) emission standards, although there is disagreement on whether such EEE measures could be mandatory (i.e. taken into account in determining the stringency of the standard) or a voluntary alternative compliance option for regulated entities.

If EPA were to base its Section 111(d) performance guidelines on the perceived availability of EEE measures, then there are significant questions about whether and to what extent such reductions can satisfy EPA guidance. As discussed below, EPA already has issued guidance to States interested in claiming State Implementation Plan (SIP) credit for such measures. A separate, but important, question is whether and to what extent such reductions also could be made available to regulated units for compliance purposes.

**Relevant EPA Guidance**

There are no existing statutory or regulatory provisions nor EPA policy guidance that address crediting CO₂ reductions from State EEE policies or programs for compliance with EPA stationary source regulations. However, EPA has prepared extensive guidance on providing SIP credit for criteria pollutant reductions from State EEE measures. While that guidance addresses different pollutants under a separate regulatory framework, there are aspects of the guidance that may help inform the discussion in the CO₂ emissions context.

EPA’s guidance recognizes a number of different pathways for these EEE measures to be credited or incorporated into SIPs. For instance, EPA provides guidance on how SIPs can incorporate EEE measures into SIPs as creditable control strategies or as emerging and/or voluntary measures. See EPA, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, 14 (July 2012) (hereinafter “Roadmap”).

EPA’s guidance explains that for States to credit EEE measures as control strategies in their SIPs, States must document that emissions reductions from the EEE policy or program are quantifiable, surplus, enforceable and permanent. See Roadmap at 30. EPA acknowledges that these documentation and quantification efforts constitute a significant undertaking. See Roadmap at 35. EPA guidance allows for EEE measures to be included in SIPs as emerging and/or voluntary measures, and this forward-looking approach could provide some flexibility with respect to quantification and enforceability.

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1 EPA has stated that the 2012 Roadmap is a document intended to clarify existing guidance and does not create new guidance. See Roadmap at 16.
Quantifiable: EPA guidance directs States to use reliable and replicable emissions quantification approaches. See Roadmap at 36. The guidance notes that the measures should include “procedures to evaluate and verify over time the level of emission reductions actually achieved.” EPA, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions From Electric-Sector Energy Efficiency and Renewable Energy Measures, 5, 22-23 (Aug. 2004) (hereinafter “August 2004 Guidance”). EPA acknowledges that quantification may be more difficult with emerging and/or voluntary measures. Thus, EPA guidance allows States to include “provisional” reductions for reasonable further progress demonstrations and other purposes, see Roadmap at C-9, and those reductions can become permanent “when post-implementation evaluations validate the amount of emission reductions achieved.” EPA, Incorporating Emerging and Voluntary Measures in a State Implementation Plan, 13 (Sept. 2004) (hereinafter “September 2004 Guidance”). EPA recommends that the post-implementation evaluation and reconciliation of a measure should occur no later than 18 months after the measure is in place. See id. at 17. If the post-implementation evaluations show that the reductions did not occur, then States would be responsible for reconciling the shortfall. See id. at 13. EPA suggests that an assumed discount of 20 percent be used when estimating reductions from an emerging measure, due to uncertainty of estimates. See September 2004 Guidance at 16. For emerging and/or voluntary EEE measures, EPA sets the “presumptive SIP credit limit” to six percent of the total amount of emission reductions required for reasonable further progress, attainment or maintenance demonstrations. See Roadmap at 37; September 2004 Guidance at 9. Thus, in the absence of very substantial empirical and program development work to demonstrate actual emission reductions to support credit for such approaches, emerging and/or voluntary EEE measures can generally only be a small part of the SIP.

Surplus: EPA guidance explains that, to count in the SIP, States must document that reductions from EEE measures are not double counted and demonstrate that those reductions are not being used for other CAA requirements. See Roadmap at 36. The guidance notes particular difficulty of demonstrating that emission reductions are surplus in areas that are subject to cap-and-trade requirements. EPA notes that one way to demonstrate that emission reductions are surplus in this context is through the retirement of allowances in amounts commensurate to reductions expected from the EEE measures. See Roadmap at Appendix C-6; August 2004 Guidance at 10.

Enforceable: Once EEE measures are approved as control measures in the SIP, EPA notes that they are federally enforceable against the regulated source or the implementing party. See Roadmap at 30. In contrast, voluntary EEE measures that are not enforceable against a regulated source or implementing party require a State to make an enforceable commitment to implement the measures (where applicable), monitor, evaluate and report on progress, and remedy any shortfall if the EEE measure does not achieve the projected reductions. See Roadmap at 37. In other words, under the guidance, States are required to ensure that the voluntary EEE reductions actually occur, and the guidance states that reductions from voluntary EEE measures can only be credited to the State under the policy. See September 2004 Guidance at 19.

Permanent: EPA’s guidance notes that the EEE measure must be permanent during the term in which the SIP credit is granted unless another measure replaces it or a SIP revision eliminates the need for the credit. See Roadmap at 36.
Among the challenges that EPA has identified for incorporating EEE measures into SIPs is the need to establish partnerships between environmental agencies and other state agencies that may not typically collaborate, such as public utility commissions and state energy offices. See Roadmap at 15. EPA has also noted the challenge of quantifying emissions reductions from these measures. See id.

**Considerations for Establishing Protocols to Credit State EEE Measures for Use in a Power Sector 111(d) Program**

Aside from the important question of whether anticipated net greenhouse gas reductions from EEE measures can be a basis for setting mandatory electric generating unit performance in a Section 111(d) standard or can instead be available through the trading of emission reduction credits as a voluntary alternative compliance option, there are important threshold considerations regarding whether and how reductions from these measures could be credited in a Section 111(d) program. These considerations generally fall within the requirement categories that EPA has outlined for crediting criteria pollutant reductions in SIPs, each of which poses significant challenges for power sector application.

**Quantifiable:** The quantification of CO₂ reductions from EEE measures for the purpose of crediting those reductions in a Section 111(d) program depends on a number of technically and economically complex issues. As an initial consideration, the research literature on energy efficiency indicates that there are significant challenges in estimating how much energy use is actually avoided by EEE measures, with significantly lower estimates flowing from empirical analysis than from before-the-fact engineering studies. In addition, there is a real question whether certain EEE measures may, by effectively making energy cheaper, trigger expanded energy consumption, which could offset engineering estimates of emission reductions.

The question of how EEE measures impact dispatch will be another significant consideration. *Where* electricity generation changes in response to EEE measures affects overall emission reductions because each EGU has a different emission rate, based on the fuel and process used. In other words, whether the EEE measures displace high or low carbon intensive electricity generation (e.g., gas, coal or nuclear and renewable generation) is an important consideration in quantifying reductions. *When* electricity generation changes also has an important impact on the quantification because of the variability of generation at different times of the day or year. These and other considerations make it very difficult to quantify net greenhouse gas emissions, particularly if one must know the quantity and location of reductions in advance.

**Surplus:** The determination of what CO₂ reductions from EEE measures are surplus rather than merely occurring at a spontaneous and natural rate of adoption of measures is another important consideration. This is particularly important if States have existing EEE policies or programs for which they want to quantify and credit CO₂ reductions in a Section 111(d) program.

One approach to demonstrating surplus reductions would be to allow states with high-performing energy efficiency programs to generate credit for decremental energy consumption and verifiable resulting net emission reductions attributable to the EEE measures. Surplus reductions could be demonstrated by crediting only efficiency achieved beyond a suitable benchmark that reflects an ongoing natural rate of adoption and that adjusts for any increased use of electricity due to
reductions in its effective cost; while real emission reductions could be verified by a suitable analytical approach that estimates the actual changes in dispatch due to the net improvements in energy efficiency, while controlling for other factors that affect generation utilization. Any such analysis would almost certainly have to be conducted in retrospect (i.e., after the fact) when more is known about actual energy consumption and the mix of generation during a specific period of time. Another approach that EPA has suggested in the context of its criteria pollutant guidance is the retirement of allocations in a cap-and-trade program. See Roadmap at Appendix C-6; August 2004 Guidance at 10.

**Enforceable:** Enforceability of EEE measures will likely raise a number of challenges in crediting EEE measures in a Section 111(d) program. As EPA acknowledged in its criteria pollutant guidance, most EEE measures would not be enforceable directly against a regulated stationary source. See Roadmap at Appendix C-6; August 2004 Guidance at 5. This raises important questions: who would be liable? how would compliance be verified? would failure to achieve reductions constitute a “violation”? what would the penalty be? who would be subject to citizen suits?

If enforcement and other challenges make it difficult to assign emission reductions credit (ERC) to specific generating units or to performing third parties (for trade as discrete ERCs in the marketplace), then the use of an alternative compliance payment (ACP) approach may be a more feasible method of linking EEE reductions to the Section 111(d) program. See Background Paper on Alternative Compliance Payment Program.

**Permanent:** An important consideration for crediting CO₂ emission reductions from EEE measures is the term in which the measure must be continued and how that would be verified to demonstrate permanency. Depending on the EEE measure, this could raise significant practical challenges. Consider, for instance, the challenges of permanency and verification for a program in which home owners replace incandescent light bulbs with compact fluorescent bulbs. Would a crediting program take into account the possibility that a home owner could later reinstall the incandescent light bulb, or that they might delay switching to even more efficient LED lighting as a result of the EEE measure? There will be similar challenges for providing compliance or program credit for any number of demand-side EEE strategies.
A ceiling-price alternative compliance payment (ACP) offers multiple benefits as a potential voluntary compliance option that EPA could consider in its Section 111(d) guidelines for State adoption. It could fund State-directed energy-efficiency and low-carbon energy (i.e., cleantech) investments and serve as a safety valve if compliance costs are higher than anticipated. As outlined below, this policy instrument was first recognized by the Clinton Administration as a compliance option for implementing revised criteria pollutant standards. EPA has approved such a compliance alternative as part of a State Implementation Plan (SIP) revision under Section 110 of the Act, so there is both policy and legal precedent for such an approach.

Previous CAA Mitigation Fee Programs

Although the ceiling-price ACP concept was first introduced during Congressional staff discussions during the 1990 Clean Air Act Amendments as a strategy that could address compliance challenges when costs exceeded anticipated levels, the first formal articulation of the idea appeared in President Clinton’s July 1997 Memorandum to EPA when EPA revised the National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. Recognizing that the revised standards could impose an unanticipated level of cost on regulated sources, the Memorandum recommended an ACP option for sources facing control costs above a cost-effectiveness threshold to fund reductions from other sources and to stimulate new technologies:

There is a strong desire to drive the development of new technologies with the potential of greater emission reduction at less cost. It was agreed that $10,000 per ton of emission reduction is the high end of the range of reasonable cost to impose on sources. Consistent with the State's ultimate responsibility to attain the standards, the EPA will encourage the States to design strategies for attaining the PM and ozone standards that focus on getting low cost reductions and limiting the cost of control to under $10,000 per ton for all sources. Market-based strategies can be used to reduce compliance costs. The EPA will encourage the use of concepts such as a Clean Air Investment Fund, which would allow sources facing control costs higher than $10,000 a ton for any of these pollutants to pay a set annual amount per ton to fund cost-effective emissions reductions from non-traditional and small sources. Compliance strategies like this will likely lower the costs of attaining the standards through more efficient allocation, minimize the regulatory burden for small and large pollution sources, and serve to stimulate technology innovation as well.


EPA has in fact approved SIP revisions, under CAA Section 110, that incorporate just such a mitigation fee program. In 1999, the South Coast Air Quality Management District in California amended its Rule 1121 (“Control of Nitrogen Oxides from Residential Type, Natural Gas-Fired Water Heaters”) to include a mitigation fee alternative. This mitigation fee alternative was
defined as an “emission reduction option, in which monies collected by the District from water heater manufacturers are placed in a restricted fund and are used to fund stationary and mobile source emission reduction programs targeted at equivalent NOx emission reductions as to those that would have otherwise occurred and have been approved by the District’s Governing Board.” Rule 1121(b)(5). EPA approved that amendment as part of revisions to California’s SIP in 2001. See EPA, Revisions to the California State Implementation Plan, California State Implementation Plan Revision; San Joaquin Valley Unified Air Pollution Control District, and South Coast Air Quality Management District: Direct Final Rule, 66 Fed. Reg. 57666 (Nov. 16, 2001). The South Coast Air Quality Management District later amended Rule 1121 in 2004, retaining and updating the mitigation fee alternative. EPA also approved that amended version of the rule as a revision to California’s SIP in 2009, noting that the “rule includes a mitigation fee that can be paid in lieu of meeting interim emission limits....” EPA, “Revisions to the California State Implementation Plan, South Coast Air Quality Management District Sacramento Metropolitan Air Quality Management District: Direct Final Rule,” 74 Fed. Reg. 20880, 20881 (May 6, 2009).

How An ACP Program Could Work

EPA could provide States the ACP framework as an independent model rule component that States could adopt in their Section 111(d) plans. EPA could identify appropriate qualifying criteria for fund investments to ensure that the investments are designed to achieve CO2 emission reductions. However, the State would control the program – i.e., a State would choose whether to implement the fund as a compliance option, would collect the funds and would identify those investments that best match its energy objectives and CO2 emission reduction opportunities. Such a program could accelerate investment in energy efficiency, renewable energy, energy storage and carbon capture and sequestration.

EPA would establish the ceiling price that would enable a source to use the ACP. To enable this feature, it would be important for EPA to identify the upper bound of anticipated compliance cost (i.e., cost per ton of greenhouse gas emissions reduced) for its Section 111(d) performance standard, based upon the empirical analysis it conducts when developing or adjusting the standard.