Legal Memorandum Accompanying Clean Power Plan for Certain Issues

This document includes additional information concerning certain legal issues relevant to the Clean Power Plan. This document is intended to be read in conjunction with the preamble and the Response to Comments document. In connection with the proposed Clean Power Plan, we included in the docket a legal memorandum that provided our proposed position on a variety of legal issues. The discussion of legal issues contained in the preamble for the final rule, this Memorandum, and the Response to Comments Document supersede some of the preliminary interpretations taken in that document, as indicated in the preamble or this Memorandum.

Relationship between the Building Blocks and the BSER for New EGUs.

In this section, in response to comments, we describe why we have not included building blocks 1, 2, and 3 as part of the BSER for new sources in the section 111(b) rule. This section largely reproduces section XI of the section 111(b) preamble.

In the CAA section 111(b) rule for new, modified, and reconstructed steam units and new and reconstructed combustion turbines that the EPA is promulgating at the same time as this CAA section 111(d) rule, the EPA is not identifying as part of the BSER for those sources building block 1 (for steam units, efficient operation), building block 2 (for steam units, dispatch shift to existing NGCC units), and building block 3 (for steam units and combustion turbines, substitution of generation with new renewable energy). In this section, we explain our reasoning.

A. **Newly constructed steam generating units.**

As discussed in this preamble and in more detail in the preamble to the CAA section 111(d) rule for existing sources, the phrase “system of emission reduction” is undefined and provides the EPA with discretion in setting a standard of performance under CAA section 111(b) or emission guidelines under CAA section 111(d). Because the phrase by its plain language does not limit our review of potential systems of emission reduction in either context, the same systems could be considered for application in new and existing sources. That said, many other factors and considerations direct us to focus on different systems when establishing a standard of performance under CAA section 111(b) and an emission guideline under CAA section 111(d). Thus, it is useful to describe part of the underlying basis for the BSER – partial CCS - that the EPA has determined for new steam units before discussing the building blocks that form the BSER for existing units.

For new steam generating units, the EPA is identifying, as the BSER, systems of emission reduction that assure that these sources are inherently low-emitting at the time of construction. The following reasons support this approach to the BSER.

New sources are expected to have long operating lives over which initial capital costs can be amortized. Thus, new construction is the preferred time to drive capital investment in emission controls. In this case, the BSER for new steam generators, partial CCS, requires substantial capital expenditures, which new sources are best able to accommodate.

While CAA section 111(b)(1)(B) and (a)(1) by their terms do not mandate that the BSER assure that new sources are inherently low emitting, that approach to the BSER is consistent with the legislative history.[1] For instance, the 1970 Senate Committee Report explains that "[t]he overriding purpose of this section [concerning new source performance standards] would be to prevent new air pollution problems, and toward that end, *maximum feasible control of new sources at the time of their construction* is seen by the committee as the most effective and, in the long run, the least expensive approach."[2] Existing sources, on the other hand, would be regulated through emission standards, which were broadly understood at the time to reflect available technology, alternative methods of prevention and control, alternative fuels, processes, and operating methods.[3,4]

In this case, the BSER for new steam generators, partial CCS, requires substantial capital expenditures, which new sources are best able to accommodate.

1. Practical implications of including the building blocks.

Regardless of whether the EPA can prefer technological controls when setting new source standards, several practical considerations make the building blocks inappropriate for new sources. Thus, for the following reasons, the EPA does not consider it appropriate to include the building blocks as part of the BSER for new sources:

Partial CCS will impose substantial costs on new steam-generating EGUs, and, as a result, the EPA does not believe that including additional measures as part of the BSER would be appropriate. One disadvantage in adding additional costs is that doing so would make it more difficult for new steam-generating EGUs to compete with new nuclear units. Because the BSER is selected after considering cost (among other factors), the EPA is not required to,[5] and in this

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[1] Although Congress expressed a clear preference that new sources would be "designed, built, equipped, operated, and maintained so as to reduce emissions to a minimum," the Senate Committee Report also makes clear that the term standard of performance "refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods*." Sen. Rep. No. 91-1196 at 15-17, 1970 CAA Legis. Hist. at 415-17 (emphasis added).

[2] Sen. Rep. No. 91-1196 at 15-16, 1970 CAA Legis. Hist. at 416 (emphasis added).

[3] *See* 1970 CAA Amendments, Pub. L. 91-604, § 4, 84 Stat. 1676, 1679 (Dec. 31, 1970) (describing information that the EPA must issue to the states and appropriate air pollution control agencies along with the issuance of ambient air quality criteria under Section 4 of the 1970 CAA titled "Ambient Air Quality and Emission Standards").

[4] In the 1977 CAA Amendments, Congress revised section 111(a)(1) to mandate that the EPA base standards for new sources on technological controls, but, at the same time, made clear that the EPA was not required to base the emission guidelines for existing sources on technological controls. In the 1990 CAA Amendments, Congress repealed the section 111(a)(1) requirements that distinguished between new and existing sources and largely restored the 1970 CAA Amendments version of section 111(a)(1).

[5] For example, as early as a 1979 NSPS rulemaking for affected EGUs, the EPA recognized that it was not required to establish as the BSER the most stringent adequately demonstrated system

case believes it would not be appropriate to, select the most stringent adequately demonstrated system of emission reduction (through the combination of partial CCS and the building blocks) for purposes of setting a standard of performance under CAA section 111(b).

In addition, building block 1 measures are not appropriate because the BSER for new steam generating units is based on highly efficient supercritical technology, i.e., state-of-the-art, efficient equipment. Accordingly, there is little improvement in efficiency that can be justified as part of the BSER.

Building block 2 and 3 measures are not appropriate for the BSER because new steam units would have a significantly limited range of options to implement building blocks 2 and 3. The new source performance standard was proposed and is being finalized as a rate-based standard. Thus, if building blocks 2 and 3 were included in the BSER, a more stringent rate-based standard would be applicable to all new sources. However, it is conceivable that EPA could propose a hybrid standard that would include both an emission-rate limit that reflects partial CCS and a requirement for allowances that reflects building blocks 2 and 3. Accordingly, the following discussion assumes either a rate-based or mass-based standard, or part of a hybrid standard.

In both a rate-based program and a mass-based program, building blocks 2 and 3 measures can be implemented through a range of methods, including trading with other EGUs. While it is not necessarily the case that every existing source will be able to implement each of the methods, in general, existing sources will have a range of measures to choose from. However, at least some of those methods may not be available to new sources, which would render compliance with their emission limits more challenging and potentially more costly.

One example is emission trading with other affected EGUs. For existing sources, emission trading is an important option for implementing the building blocks. There are large numbers of existing sources, and they will become subject to the section 111(d) standards of performance at the same time. It may be more cost-effective for some existing sources to implement the building blocks than others, and, as a result, some may over-comply and some may under-comply, and the two groups may trade with each other. Because of the large numbers of existing sources, the trading market can be expected to be robust. Trading optimizes efficiency. As a result, existing sources have more flexibility in the overall amount of their investment in building blocks 2 and 3, and can adjust investment obligations among themselves through emissions trading.

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of emission reduction available, and instead could weigh the amount of additional emission reductions against the costs. *See* 44 F.R. 52792, 52798 (Sept. 10, 1979) ("Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.").

In contrast, new sources construct one at a time, and it is unknown how many new sources there will be. Without a sizeable number of new sources, there will not be a robust trading market. Thus, a new source cannot count on being able to find a new source trading partner.

In addition, it is not possible to count on new sources being able to trade with existing sources, for several reasons. First, as noted, there are indications in the legislative history that new sources should be well-controlled at the source, which casts doubt on whether new sources should be allowed to meet their standards through the purchase of emission credits. Second, new sources must meet their standards of performance as soon as they begin operations. If they do so before the year 2022, when existing sources become subject to section 111(d) state plan standards of performance, no existing sources will be available as trading partners.

In addition, for section 111(d) sources, we are granting a 7-year period of lead-time before the implementation of the building blocks. This is due, in part, to the benefits of allowing the ERC and allowance markets to develop. However, the new source standards take effect immediately, so that new sources would not have the advantage of this lead time were they subject to more stringent standards reflected in the building blocks.[6]

In addition, if there are an unexpectedly large number of new sources, then they would be obliged to invest in greater amounts of building blocks 2 and 3, and that could reduce the amounts of building blocks 2 and 3 available for existing sources, and thereby raise the costs of building blocks 2 and 3 for existing sources. This could compromise the BSER under section 111(d) and undermine the ability of existing sources to comply with their section 111(d) obligations.[7]

B. New combustion turbines.

For new combustion turbines, the building blocks are not appropriate as part of the BSER for the following reasons: Building block 1 is limited to steam generating units, and therefore has no applicability to new combustion turbines. Measures comparable to those in building block 1 would not be appropriate because the highly efficient NGCC construction already entails high efficiency equipment and operation.

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[6] At least in theory, we could consider promulgating a standard of performance for new affected EGUs that becomes more stringent beginning in 7 years, based on a more stringent BSER. We are not inclined to adopt that approach because section 111(b)(1)(B) requires that we review and, if necessary, revise the section 111(b) standards of performance no later than every 8 years anyway.

[7] The EPA is authorized to consider the BSER for new and existing sources in conjunction with each other. In the 1977 CAA Amendments, Congress revised section 111(a)(1) to require technological controls for new combustion sources at least in part because this requirement would preclude new sources from relying on low-sulfur coal to achieve their emission limits, which, in turn, would free up low-sulfur coal for existing sources.

Building block 2 is also limited to steam generating units and is not appropriate as part of the BSER for new NGCC units because it would not result in any emission reductions.

The reasons why building block 3 are not appropriate are the same as discussed above for why building blocks 2 and 3 are not appropriate for new steam generating units (limited range of options for implementation (including lack of availability of trading), lack of lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

C. Modified and reconstructed steam units and reconstructed NGCC

For modified and reconstructed steam generators, the EPA identified the BSER as maintenance of high efficiency or implementation of a highly efficient unit. The resulting emission limit must be met over the specified time period and cannot be deviated from or averaged. As a result, a modified or reconstructed steam generator generally will require ongoing maintenance, and may find it prudent to operate below its limit as a safety margin. This represents a substantial commitment of resources. For these units, the additional costs of implementing the building blocks would not be appropriate.

In addition, building block 1 is not appropriate for modified or reconstructed steam generating units because the BSER for these units is already based on highly efficient performance. For the same reasons, it does not make sense to attempt to develop the analogue to building block 1 for reconstructed NGCC units – the BSER for them, too, is already based on highly efficient performance.

Building block 2 is not appropriate for reconstructed NGCC units because it would not yield any reductions.

Building blocks 2 and 3 are not appropriate for modified or reconstructed steam generators, and building block 3 is not appropriate for reconstructed NGCC units, for the same reasons that they are not appropriate for new EGUs, as described above (limited range of options for implementation (including lack of availability of trading), lack of lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

II. Uniqueness of CO_2 and of the Electric Power Sector

In section V.A.2.b of the preamble, we note the reasons why CO_2 is a unique air pollutant and why the electric power sector is a unique source category, and the critical importance of those characteristics in shaping this rule. Here we note that the U.S. Supreme Court has recognized both the uniqueness of CO_2 and the electric power sector. In *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014), the Court recognized that greenhouse gases like carbon dioxide are "atypical pollutants" that are emitted in "vast quantities." *Id.* at 2442; *see also AEP v. Connecticut*, 131 S. Ct. 2527, 2538 (2011) ("Congress could hardly preemptively prohibit every

discharge of carbon dioxide unless covered by a permit.”).[8] Moreover, the Supreme Court has repeatedly affirmed the authority and responsibility of the agency, charged with implementing the Clean Air Act, to deploy its expertise and the exercise of its discretion to fashion workable regulatory frameworks for greenhouse gases. *UARG*, 134 S. Ct. at 2441, 2442 (directing the agency to use its discretion and look to “statutory context” in applying the CAA to greenhouse gases); *AEP*, 131 S. Ct. at 2539 (“Congress delegated to EPA the decision whether and how to regulate carbon dioxide emissions from power plants ....”); *id.* at 2539 (“It is altogether fitting that Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of greenhouse gas emissions.”). *See also AEP*, 131 S. Ct. at 2539 (“The appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum …, informed assessment of competing interests is required.”).

The Court has also recognized the uniqueness of the electric power sector. This sector is the single largest contributor to national CO_2 emissions (in addition to other air pollutants); as the preamble notes, it operates as a large machine, i.e., as an interconnected entity; and it is economically critical to the country. This uniqueness is recognized by Congress throughout the Clean Air Act, including in various provisions of section 111.[9] The Supreme Court recently directed the agency to fully exercise its discretion by considering costs in determining whether it is “appropriate and necessary” to regulate hazardous air pollutants from the power sector under section 112(n). *See Michigan v. EPA*, No. 14-46, at 6 (June 29, 2015) (Slip Op.) (“The Clean Air Act treats power plants differently from other sources for purposes of the hazardous-air-pollutants program.”). As required under section 111, in the Clean Power Plan, the agency has, of course, considered costs among the other factors relevant to the power sector in determining the “appropriate amount of regulation” for carbon dioxide. As we discuss elsewhere, Congress added section 112(n) in the 1990 CAA Amendments, at the same time that it added Title IV to regulate acid rain precursors from the electric power sector and revised section 111 with respect to the electric power sector, and linked the Title IV revisions to the section 111 revisions.

Numerous commenters objected that the EPA has never applied measures like the building blocks in section 111 rules, and asserted that the EPA was departing from long-standing precedent without explaining why. We disagree with these comments. As we explain in section V.A.2.b of the preamble, to determine the BSER, we began by considering the characteristics of CO_2 pollution and the utility power sector. We have not previously regulated CO_2 pollution from the utility power sector, and the combination of the unique characteristics of that air pollutant with the unique characteristics of that sector have led us to include building blocks 2 and 3 in the BSER. As we note in the preamble, not surprisingly, whenever the EPA begins the regulatory process under section 111, we initially undertake these same inquiries into the nature of the industry and the air pollutant and then proceed to fashion the rule to fit the industry. Thus, our approach to this rulemaking is consistent with our approach to previous section 111 rules.

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[8] The Court in *UARG* did not grant certiorari on, and in its opinion recognized, the agency’s conclusion that greenhouse gases are a pollutant under the CAA because they endanger public health and welfare by fostering global climate change. *See UARG*, 134 S. Ct. at 2436-37.
[9] *See* sections 111(a)(7)(B), 111(a)(8), and 111(b)(6).

III. NSPS Rulemakings and the Integrated Grid

This section provides a more detailed description of two EPA NSPS rulemakings that relied on the integrated grid, which supports the discussion in the preamble in section V.B.3.c.(6)(c).

On June 11, 1979, EPA finalized new standards of performance to limit emissions of sulfur dioxide, particulate matter, and nitrogen oxides from new, modified, and reconstructed electric utility steam generating units.[10] The revised standards limited sulfur dioxide emissions to 1.20 ppm BTU heat input for solid derived fuel and 0.80 ppm heat input for liquid or gaseous fuels. In both instances, a 90 percent reduction was also required.[11] A 70 percent reduction was required for solid derived fuels when emissions are less than 0.60 ppm BTU heat input, and a zero percent reduction was required for liquid or gaseous fuels when emissions are less than 0.20 ppm BTU heat input.[12] In selecting these standards, the Administrator investigated "coal cleaning and the relative economics of FGD [flue gas desulfurization] and coal cleaning" together as the "best demonstrated system for SO_2 emission reduction."[13] Compliance with the standards could be met through credits "for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion."[14]

Notably, in assessing the best demonstrated system against concerns of electric service reliability, the Administrator took into account "the generating capacity of the affected utility company…, and the amount of power that could be purchased from neighboring interconnected utility companies."[15] Part of this analysis noted that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations."[16] The Administrator determined that a broad exemption from the standards was not necessary "because load can usually be shifted to other electric generating units."[17]

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[10] *See* New Stationary Sources Performance Standards; Electric Utility Steam Generating Units, 44 F.R. 33580 (June 11, 1979).
[11] 44 F.R. 33580, 33614.
[12] 44 F.R. 33580, 33614.
[13] 44 F.R. 33580, 33593. The amount of sulfur that could be removed from coal was investigated by the U.S. Department of the Interior and considered sulfur reduction potential of coal cleaning for the Eastern Midwest and the Northern Appalachian Coal regions. *Id.* at 33593.
[14] 44 F.R. 33580, 33581. In order to receive credit for fuel pretreatment, owners or operators of an affected facility must list the "quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter. *Id.* at 33619.
[15] 44 F.R. 33580, 33597.
[16] 44 F.R. 33580, 33599.
[17] 44 F.R. 33580, 33600. A limited exemption that "allow[ed] an owner or operator to bypass uncontrolled flue gases around a malfunctioning FGD system" was permitted so long as three conditions were met: "(1) the FGD system has been constructed with a spare FGD module, (2) FGD modules are not available in sufficient numbers to treat the entire quantity of flue gas generated, and (3) all available electric generating capacity is being utilized in a power pool or

Moreover, "reducing the level of electric generation" could be implemented in the case of a failed FGD module and would not affect the remainder of the FGD system, thus "permit[ting] the utility to maintain compliance with the standards without having to take the generating unit entirely out of operation."[18] In other words, "a properly designed FGD system has no routine need for an exemption from the SO_2 percentage reduction requirement when the unit is operated at reduced load."[19] Accordingly, an exemption from the standards was "not necessary to protect electric service reliability or to maintain compliance with the[] SO_2 standards."[20] These standards were upheld by the D.C. Circuit in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981).

> Similarly, in a 1982 rulemaking promulgating an NSPS, the EPA stated:
> The EPA position is that unlike utility turbines, industrial turbines in some instances may represent the sole primary energy source for a major industrial process. Such a turbine could not be shut down more frequently without an unacceptable economic consequence. The unacceptable economic consequence could be that an entire plant or process depends on the continuously running gas turbine. This is not the case for utility turbines, however, since other electric generators on the grid can restore lost capacity caused by turbine down time. Inspection and maintenance can be scheduled for a low load period when full generating capacity is not needed. Since inspection and maintenance of continuously running utility turbines is not economically unreasonable, the NOx emission limit for these turbines has not been rescinded.

47 F.R. 3767, 3768 (Jan. 27, 1982).

Commenters argue that the source-category basis for section 111 provides another reason why, in their view, the EPA is not authorized to base emission limits on controls that involve other entities, such as the measures in building blocks 2 and 3. As the above examples illustrate, even though, in past rulemakings, the EPA has generally been able to assure emission reductions from affected EGUs through control measures that apply on-site, the fact that the affected EGUs are part of the interconnected grid has informed some of the regulatory requirements. In the present rulemaking, the EPA's reliance on the interconnected grid in determining that the BSER includes the measures in building blocks 2 and 3 is not inconsistent with what commenters describe as the source-category basis for section 111; rather, the EPA's reliance on the interconnected grid recognizes that the affected EGUs, which remain the subject of the emission reduction obligations, interact with other generators, consumers, and other entities through the interconnected grid in a manner that furnishes opportunities for emissions reduction.

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network consisting of the generating capacity of the affected utility company (except for the capacity of the largest single generating unit in the company), and the amount of power that could be purchased from neighboring interconnected utility companies." *Id.* at 33597.

[18] 44 F.R. 33580, 33600. In other words, because FGD systems could be designed to have backup modules, a malfunctioning module could be bypassed and, combined with reduced generation, total flue gas generated could be routed through the backup module and the standard could still be met.

[19] 44 F.R. 33580, 33600.

[20] 44 F.R. 33580, 33600.

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IV. Additional Response to Comments Concerning Section 111(h)

Some commenters rely on Section 111(h) to argue for a contextual constraint on defining a standard of performance for purposes of section 111(d). We respond to these comments in section V.B.3 of the preamble, and add additional information here.

Section 111(h)(1) states that –

> if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, [she] may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Section 111(h)(2) provides that it is "not feasible to prescribe or enforce a standard of performance" when 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.

Commenters infer that these provisions limit EPA's interpretation of the BSER to the use of a pollution control conveyance at the source. This inference is unfounded and conveys a misunderstanding of Section 111(h).

As discussed in section V.B of the preamble, section 111(h) concerns the relatively rare situation in which an emissions standard, which entails a numerical limit on emissions, *is not* appropriate because emissions cannot be measured, due either to the nature of the pollutant (*i.e.*, the pollutant is not emitted through a conveyance) or the nature of the source category (*i.e.*, the source category is not able to conduct measurements). In such cases, the Administrator is authorized to require sources to implement specific actions to control pollution, in the form of design, equipment, work practice, or operational standards. When an emissions standard *is*

appropriate, including in the present rule, section 111(h) is silent as to what types of measures—whether or not limited to a source's own design or operations—may considered as a system of emission reduction.

Moreover, it is far from clear that even section 111(h) draws a line between on-site and off-site measures. In particular, section 111(h) authorizes the Administrator to adopt a "work practice … standard" (section 111(h)(1)) or "alternative means of emission limitation" (section 111(h)(3)), which, by their terms, could include on-site or off-site activities. In fact, the distinction between on-site and off-site measures is nowhere to be found in section 111. Section 111(h) merely provides that, under circumstances in which a source's air pollutant cannot be measured, in light of the fact that it is impossible to set a numerical limit on the source's emissions, the Administrator may promulgate other types of controls. Even if section 111(h) standards were limited to on-site actions, this would be a function of the fact that a more limited range of measures for reducing emissions is available to a source when the emissions cannot be measured,[21] and this would be further evidence that Congress knew how to draw a line between on-site and off-site measures in section 111, which indicates that because Congress did not do so in section 111(a)(1), it did not intend such a distinction.

This interpretation of section 111(h) is confirmed by its legislative history. Section 111(h) was added in the Conference Committee to reflect similar changes to section 112(e) as part of the 1977 CAA Amendments. As with section 111(h), Congress added section 112(e) to allow the promulgation of "a design, equipment, work practice, or operational standard, or combination thereof, which in [the Administrator's] judgment is adequate to protect the public health from such pollutant or pollutants with an ample margin of safety."[22] Congress endorsed this addition because "[s]ection 112 of the existing law [had] been interpreted by some courts as only allowing the use of numerical emission standards."[23] As a result, Congress intended to "fully authorize ... EPA regulations governing asbestos," which had been "demonstrated as requiring other than a direct numerical emission limitation."[24] In fact, Congress observed that "[w]ork practice and other design characteristics" appeared to be "the only means available for controlling such pollutants."[25] Accordingly, sections 111(h) and 112(e) draw a distinction between quantitative levels of control (as reflected by, for example, a standard of performance) and qualitative levels associated with work practice or design standards.[26] Nothing in the legislative history suggests that Congress intended for section 111(h) to constrain our interpretation of section 111(a)(1).

For these reasons, we find nothing in the plain language of section 111(h) or in its legislative history to support the inference commenters seek to draw. In any case, as we note in the preamble, section 111(h) only relates to standards of performance imposed by the

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[21] As noted, it is only when emissions cannot be measured that section 111(h) applies.
[22] 1977 CAA Amendments, at § 110, 91 Stat. at 703.
[23] Sen. Rep. No. 95-127, at 44 (May 10, 1977).
[24] Sen. Rep. No. 95-127, at 44 (May 10, 1977).
[25] Sen. Rep. No. 95-127, at 44 (May 10, 1977).
[26] *See, e.g.*, *Adamo Wrecking Co. v. U.S.*, 434 U.S. 275, 286 (1978) (recognizing this distinction under section 112 "now endorsed by Congress").

Administrator (*i.e.*, under section 111(b)) and should have no bearing on our interpretation for purposes of section 111(d).

V. AEP v. Connecticut

This section provides additional information based on the Supreme Court's 2011 decision in *American Electric Power v. Connecticut*, 131 S. Ct. 2527 (2011) ("*AEP*") that is relevant to the EPA's interpretation of section 111(d)(1) and (a)(1) in section V.B.3 of the preamble.

A. The *AEP* decision

In interpreting the scope of the Agency's section 111(d) authority, the EPA was also guided by case law, including the Supreme Court's 2011 decision in *American Electric Power v. Connecticut*, 131 S. Ct. 2527 (2011) ("*AEP*"). EPA has relied on and cited *AEP*, along with *Massachusetts v. EPA*, for the proposition that it has the authority, and the responsibility, to regulate GHGs from the power sector under CAA section 111. *See* CPP Proposal Preamble, 79 Fed. Reg. at 34853. Moreover, the Court in *AEP* clearly understood, and expected, that EPA possessed sufficient authority under section 111 to achieve meaningful and significant reductions of GHG emissions from the power sector.

In *AEP*, plaintiffs brought a federal common law claim of nuisance against five of the largest GHG emitters in the power sector. The Court held that the CAA displaced federal common law in this area. The Court articulated the test as being whether a federal statute "speaks directly to the question at issue." *Id.* at 2537 (quoting *Mobil Oil Corp. v. Higginbotham*, 436 U.S. 618, 625 (1978)). Applying this test, the Court stated, "we think it ... plain that the [CAA] 'speaks directly' to emissions of carbon dioxide from the defendants' plants." *Id.* After walking through the framework of section 111, the Court concluded, "The [CAA] itself thus provides a means to seek limits on emissions of carbon dioxide from domestic power plants—the *same relief* the plaintiffs seek by invoking federal common law. We see no room for a parallel track." *Id.* at 2538 (emphasis added).

The "relief" plaintiffs sought were caps on existing power plant emissions that would "abate their contribution to global warming." *See* Complaint, *Conn. et al. v. AEP et al.*, No. 04-civ-5669, at para. 1 (S.D.N.Y. filed July 21, 2004); *id.* para. 156 ("Defendants could generate the same amount of electricity while emitting significantly less carbon dioxide by employing readily available processes and technologies."); *cf.* S. Ct. Oral Arg. Tr., at 23, 40.

In rejecting the plaintiffs' argument that displacement cannot occur until EPA has *actually* regulated GHGs, the Court went on to analyze in greater detail the regulatory scheme for GHG reduction that Congress, in its "considered judgment," 131 S.Ct. at 2538, adopted in the CAA. "The critical point is that Congress delegated to EPA the decision whether *and how* to regulate carbon-dioxide emissions from power plants…." *Id.* (emphasis added). While noting that EPA's judgment would ultimately be subject to judicial review, the Court found a host of ways in which the delegation of power from Congress, and the expertise of the EPA, make it the primary, and the most appropriate, decision maker for reductions of GHGs, noting that the Administrator must exercise her judgment in determining which sources "cause, or contribute significantly to, air pollution." *Id.* at 2539. The Court stated:

> The appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum; as with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The CAA *entrusts such complex balancing to EPA* in the first instance, in combination with state regulators.

Id. (emphases added).

The Court characterized EPA as the expert administrative agency uniquely suited to the complex task of regulating GHGs. *Id.* at 2539 ("It is altogether fitting that Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of [GHG] emissions."). Such regulation would depend on "extensive cooperation between federal and state authorities," *id.*, and further, the Agency would be in a position (unlike a court), to "commission scientific studies or convene groups of experts for advice," "seek the counsel of regulators in the States where defendants[' power plants] are located, as well as consider and incorporate public input via the rulemaking process. *Id.* at 2540.

Further, EPA could be expected to, in the words of the Court, "apportion[] responsibility for emissions reductions" among sources, *id*. at 2539 (citing 111(b)(2) and (d)). And the Court reasoned that it was EPA, rather than the courts, who would be in the best position to "determine, in the first instance, what amount of carbon-dioxide emissions is unreasonable … and then decide what level of reduction is practical, feasible and economically viable." *Id.* at 2540.

These statements from *AEP* suggest, first, that as an essential component of its federal common law displacement analysis, the Court assumed that Congress had delegated sufficient authority to EPA, and that EPA possessed the necessary scientific, policy and regulatory tools, to address the problem of carbon pollution in a robust and comprehensive manner; and, second, that it is appropriate for the EPA to consider "what amount of carbon-dioxide emissions is unreasonable … and then decide what level of reduction is practical, feasible, and economically viable" in determining the BSER. In essence, when EPA decides what level of reduction is reasonable, the Court indicates that such judgment should be granted considerable deference, subject only to the agency's assessment of practicality, feasibility, and economic viability.

B. Industry Representations regarding Section 111 in *AEP*

This understanding of *AEP* is supported by the electric power industry's own views, as expressed in that case. These were provided in briefs to the Supreme Court in *AEP*. The EPA recognizes that the electric utility sector is large and complex, and does not necessarily speak with one voice. Even so, although many of these key representatives of the sector have questioned the scope of the agency's legal authority under section 111(d), the information they provided to the U.S. Supreme Court regarding their views that the CAA gives the EPA broad authority to regulate carbon pollution from power plants and their views on their capacity to reduce emissions, as well as the measures they identified as available to do so—such as increasing renewable energy—are all relevant to, and, in fact, provide support to, the

reasonableness of the agency's decisions in defining the BSER, and other aspects of the Emission Guidelines.

The electric utility industry itself appeared to adopt a relatively expansive view of the EPA's authority under section 111(d) to address carbon pollution from power plants. In particular, in *AEP*, the power company Petitioners[27] and supporting electric power sector Amici[28] argued, *inter alia*, that EPA's authority under the Clean Air Act, and in particular section 111, was sufficiently broad to displace any federal common law action against the power sector based on GHG emissions.

Industry Petitioners stated to the Court, for example, that "Congress has addressed the issue of greenhouse gas emissions," Pet'rs' Br. 41, and "the Clean Air Act delegates regulatory authority over carbon dioxide emissions to EPA," *id.* at 46. Amici from the power sector further emphasized that, "Congress has 'spoken directly to the question' of GHG regulation," "and has already 'addressed the problem' plaintiffs now attempt to bring before the federal courts."[29] Amicus Br. 26 (quoting *Milwaukee v. Illinois*, 451 U.S. 304, 315 (1972)).

The Petitioners adopted a broad view of federal authority under the Clean Air Act. "'To say this regulatory and permitting regime is comprehensive would be an understatement.'" Pet'rs' Br. 42 (quoting *North Carolina ex rel. Cooper v. TVA*, 615 F.3d 291, 298 (4th Cir. 2010)). "The Clean Air Act, like the Clean Water Act, is a 'comprehensive' regulatory scheme to address environmental pollution. *Id.* at 41. "Nothing in the [CAA] or legislative history suggests that Congress intended to leave 'room for courts to attempt to improve on that program with federal common law.'" Pet'rs' Br. 41, 42 (quoting *Milwaukee II*, 451 U.S. at 319). Indeed,

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[27] American Electric Power Co., American Electric Power Service Corp., Cinergy Corp (merged with Duke Energy), Southern Company, and Xcel Energy Inc.. The federal government filed a separate brief on behalf of the Tennessee Valley Authority.

[28] Edison Electric Institute (EEI), American Public Power Association (APPA), and National Rural Electric Cooperative Association (NRECA). According to the Statement of Interest, Amicus Br. at 1-2, EEI is the national association of U.S. shareholder-owned electric utilities and affiliates and industry associates, whose members represent three-quarters of all electricity produced by U.S. energy companies and serve 70 percent of all retain customers in the U.S. APPA represents the over-2000 non-profit, publicly owned electric utilities, serving 45 million Americans. NRECA represents the 930 non-profit customer-owned rural electric cooperatives, serving 42 million end users. Together, their member companies serve 94 percent of the electric customers in the U.S.

[29] Although this memo focuses on the Petitioners' brief and the main amicus brief of the power sector, other amici on behalf of industry also put forward this position. *See, e.g.*, Amicus Brief of Consumer Energy Alliance et al. (Laurence H. Tribe, Counsel of Record), at 3 ("[J]udicial action is foreclosed by the fact that Congress has already authorized the Environmental Protection Agency (EPA) to regulate those emissions."), at 20 ("EPA possesses 'significant latitude as to the manner, timing, content, and coordination of its regulations …'" (quoting *Mass. v. EPA*, 549 U.S. at 533)), and at 35 ("By textually committing [treaty negotiation] power to the President, Article II [of the U.S. Constitution] precludes judicial authority to establish de facto regulatory standards that might disrupt a treaty-based or other internationally negotiated response to the inescapably global issue of climate change.").

"Throughout the debates and reports of Congress, [the CAA's] sponsors repeatedly characterized the Act as 'comprehensive,' and commented on its expansive reach." *Id.* at 42. "[T]he Clean Air Act vests EPA with broad authority not only to promulgate national standards for pollutants, but also to enforce those standards directly …." *Id.* at 43. "The Act is 'sweeping' and 'capacious.'" *Id.* at 41 (quoting *Massachusetts v. EPA*, 549 U.S. 497, 528, 532 (2007)).

These parties recognized, further, that "Congress has given EPA substantial authority to regulate within the context of a comprehensive legislative scheme and has left it to the Agency to oversee matters of implementation and enforcement." Amicus Br. 27; *cf. id.* at 26 ("Through the Clean Air Act, Congress chose to regulate GHGs and to *delegate the details to EPA*.") (emphasis added). See also Amicus Br. 7; *id.* at 28-29 ("It is clear that EPA has the power to regulate GHGs, and it is doing so.").

The Amicus Brief on behalf of EEI and others, in particular, gives examples of the complexity of the climate problem, and also explains why the "existing regulatory scheme" is sufficient and should not be "undermined." Amicus Br. 14 (emphasis added). This Brief also notes, "EPA's forthcoming NSPS regulations calibrate GHG performance standards to 'the best demonstrated emissions control technology' for the particular industry segment in order to avoid 'unreasonable economic disruption." *Id.* at 17-18. This initiative "is designed to produce hard emissions standards for the very power plants plaintiffs want the federal courts to regulate." *Id.* at 9.

The Amicus Brief of the power sector amici endorses the view that expanded reliance on cleaner methods of generating electricity are necessary to solve the GHG problem:

> [R]ational GHG-emissions cuts—especially the sorts of sharp reductions that some contemplate in an effort to mitigate global climate change—cannot be instituted overnight. *They will require the adoption of an array of advanced no- or low-carbon technologies, including increased use of wind, solar, incremental hydroelectric,* and nuclear power.

Id. at 16 (emphasis added). The Amicus Brief goes on to endorse the conclusion of an industry study that a scenario in which "the United States comprehensively encourages new technologies as part of its regulatory scheme" is necessary to avoid a spike in electricity prices, radical demand curtailment, or a "dash to [natural] gas" that would lead to "too high an emissions rate to satisfy ambitious long-term GHG reduction goals." *Id.* at 19-20. This discussion takes place within an argument to the Supreme Court that such a national, comprehensive regulatory scheme already exists and should not be "undermined." *Id.* at 14.

VI. Industry Statements made to the EPA Prior to Proposal of the Clean Power Plan

Representatives of the electric power industry also provided comments related to section 111(d) in the course of prior Agency rulemakings, such as the Endangerment Finding and the 2008 GHG ANPR, as well as the pre-proposal outreach sessions for the Clean Power Plan. While we recognize that there is a diversity of viewpoints in these comments, and many questioned either the appropriateness or lawfulness of regulation under section 111(d), two categories of comments are particularly relevant here: 1) several of these statements appear to endorse the

view that the BSER could encompass the measures in building block 2 (dispatch shifts from coal-fired EGUs to NGCC units) and building block 3 (renewable energy), and (2) virtually all industry commenters urged the agency to allow for these measures as effective compliance options. This second category of comments is relevant given the breadth of its support across the sector. It indicates that because the industry considers these measures to be economical and effective at achieving emission reductions for compliance, these measures merit consideration as part of the "best system of emission reduction … adequately demonstrated" itself.[30]

The electric utility industry's views on the role of the EPA under section 111, and how it should approach regulation of GHGs from the power sector, were presented during the Agency's early stakeholder engagement efforts on the section 111(d) proposal. In a "Summary of Listening Session 1: Electric Power Industry Representatives," dated February 4, 2011, we noted industry representatives' "general advice" to the agency:

- "Think of the industry as an **interconnected grid and not plant by plant**." *Id.* at 1 (emphasis in original).
- "Rate-based approach is preferred (i.e., lbs CO_2/ MWh)." *Id.*
- "Allow for technological and fuel flexibility." *Id.* (emphasis omitted).
- "Allow for flexibility for states when demonstrating equivalency." *Id.*
- For existing sources, "determine best practices nationwide using existing technologies and set the standard based on those technologies," "give states flexibility," "allow for a fleet-wide approach to meet performance standards; allow for emissions averaging and the use of offsets across companies." *Id.*
- "Approaches to avoid: limitations on the technologies that can be used to comply with the standard"; "plant by plant approach to existing units." *Id.*

Finally, the industry's representatives noted that the timeline for action should balance two core considerations: "must allow for utilities to maintain reliability (slower timeline); must move quickly to address global warming effects." *Id.* at 2.

The American Public Power Association (APPA), in comments on the Endangerment Finding, while questioning the appropriateness of NSPS regulation of GHGs, recognized the efficacy of measures not taken on site, for instance, stating, "APPA strongly believes that sequencing or other practical approaches might allow the use of energy efficiency measures involving the ultimate utility customer to be considered as a viable emissions reductions options for fossil generation electric utilities …" APA Comments on Endangerment Finding, at 23-24.

The Edison Electric Institute (EEI), in its comments on the Endangerment Finding, also questioned the use of section 111, but urged, "if EPA were to decide, nevertheless, to move forward with its existing CAA title I authorities to regulate GHG, we encourage the Agency to utilize market-based programs (i.e., cap-and-trade) instead of traditional command-and-control

[30] *See, e.g.,* Basin Electric, Draft 111(d) Design Comments (working draft), at 27 (Dec. 4, 2013) ("[E]ven the many commenters who say the Administrator's authority is limited solely to within-the-fenceline CO2 emission reductions … are also often saying that States should also be allowed to consider outside-the-fenceline reductions to meet inside-the-fenceline emission reduction requirements.").

approaches." EEI, Comments on Endangerment Finding, at 7 n.1; *see also* Appendix I to EEI ANPR comments.

The Utility Air Regulatory Group (UARG), in its comments on the Endangerment Finding, encouraged the agency to use flexible approaches under section 111(d) that would go beyond a particular unit. "Facility-wide, plant-wide, and company-wide standards would provide valuable flexibility but also complexity in trying to integrate such standards into potential economy-wide programs like trading." UARG, Comments on Endangerment Finding, at 108-09 (emphases added). In its comments on the Advanced Notice of Proposed Rulemaking (ANPR) for the Endangerment Finding, UARG stated, "The development of new technologies will be key to the ability to reduce GHG emissions from all sectors of the economy. … [T]here may be existing technologies that can be employed in the short term as identified in the ANPR, such as improved plant efficiencies, fuel switching, nuclear power, and renewable power …." UARG, ANPR Comments, at 6 (emphasis added).

In December 2013, in pre-proposal comments, the APPA stated the following, as one of the principles to guide the agency's decision making under section 111: "Recognizes the substantial emission reductions from the power sector that have already occurred and will continue to occur as a result of unit retirements, fuel switching, energy efficiency programs, and increasing use of renewable and other non-emitting or lower emitting energy sources, both voluntarily and pursuant to state mandates, among other factors."[31]

Some utility commenters explicitly urged the agency to use a system-wide approach to standard setting. For example, consensus principles the Municipal Electric Utilities of Wisconsin (MEUW) shared with the agency included:

> **Systemwide Compliance Basis** – Standards should not apply to individual plants because GHG reduction projects at individual plants are extremely limited. Allow entities to average their emissions over their entire fleet or provide for an even broader base for compliance.
>
> **Allow for Total System Emission Reducing Actions** – Affected entities should be able to comply with the standards of performance utilizing any activities that reduce emissions. These activities include supply- and demand-side energy efficiency measures, and shifting generation from fossil resources to renewables and other emission-free or lower emitting resources.[32]

Individual companies and utilities amplified these points in their pre-proposal comments, frequently highlighting the role of fuel-switching to natural gas, plant retirements, and growing renewable energy (as well as demand-side energy efficiency programs, which they believed should be credited for compliance in achieving emission reductions, even while disputing the agency's legal authority). For example, "Early action 'credit' should specifically include prior compliance actions, including retirement of coal units, system or end-user efficiency

[31] APPA, Principles on EPA Rulemakings to Establish Standards of Performance for Existing Electric Generating Units under Section 111(d) of the Clean Air Act (December 2013).
[32] Letter from MEUW to Gina McCarthy and George Czerniak, at 2 (Dec. 20, 2013).

improvements, *additions of renewable generation*, development of carbon offset projects, etc., as well as any compliance activities that can be taken inside the unit's boundaries." Am. Muni. Power & Ohio Muni. Elec. Ass'n, Ltr. to Gina McCarthy, at 7 (Dec. 2013) (emphasis added). In a joint letter, utilities in the state of Missouri made clear their opposition to the EPA's legal authority to directly impose or enforce the BSER, but went on to request that the agency recognize a broad swath of measures as compliance options, including: averaging/bubbling that could include new, lower-emitting units (i.e., across a fleet, across units in a particular state or region, among sources in the same source category or in different subcategories, among existing and closed facilities, etc.); trading; purchasing energy efficiency credits generated by the increased deployment of end-use efficiency programs*; shifting dispatch to lower-emitting generation; and adding new lower-emissions fossil fuels and renewable energy*. Letter from Missouri Utilities to Mark Smith, Branch Chief, Air Permitting and Compliance Branch, U.S. EPA, Region 7, at 4 (Nov. 27, 2013) (emphasis added).

These comments are similar in nature to many others received from various members of the power sector. *See, e.g.*, Salt River Project (SRP), State of Arizona, Responses to EPA Stakeholder Questions, at 11 (Dec. 17, 2013) ("Under [SRP's recommended phased-implementation] approach [to section 111(d)], states could establish a series of 'increments' at a rate- or mass-based level based on measures that are more likely to be achievable in the shorter term and in the longer term. For example: Short-term reductions are based on cost-effective "low-hanging-fruit" (i.e., *basic plant efficiency upgrades, incorporation of existing renewables* and demand-side efficiency programs)….") (emphasis added). At the same time these "beyond-the-fenceline" measures were touted as cost-effective compliance options for achieving substantial emission reductions, utility commenters also emphasized the relatively small emissions reductions plant efficiency upgrades could achieve on their own. *See, e.g., See* Letter from Kansas Utilities to Administrator Gina McCarthy, at 5 (May 20, 2014) ("Because EGUs inherently operate very close to their design efficiencies, we believe unit specific efficiency improvements will have limited impact on overall CO2 emission reductions."). Rather, individual utilities highlighted fuel-switching, plant retirements, RE, and demand-side energy efficiency measures as actions they were taking to substantially reduce their carbon emissions. *See, e.g., id.* at 4-5 ("Kansas is uniquely positioned to take advantage of a significant amount of renewable energy, especially wind electricity generation."); Letter from Iowa Utilities Board to Gina McCarthy and Rebecca Weber, at 3 (Dec. 6, 2013) ("Iowa has significantly increased the amount of wind generation installed in the state and has reduced the CO2 intensity of its electric generation between 2000 and 2012."); Letter from CPS Energy to EPA, at 1 (Oct. 23, 2013) ("As part of a decarbonization strategy, CPS Energy has announced it will indefinitely suspend operation of two baseload coal units … at the end of 2018. [Combined with] solar, wind, IGCC, coal gasification with carbon capture and energy efficiency will reduce overall CO2 emissions by about 45% in 2020 from baseline year 2011."); Letter from First Energy to Joseph Goffman, at 1 (Jan. 21, 2014) ("Substantial CO2 reductions have already been realized over the past decade due to … increasing renewable generation, low natural gas prices, energy efficiency programs, and retirements of older, less-efficient plants …").

Taken collectively, the body of information provided by the power sector to the agency strongly supports the technical and policy choices the EPA made in defining the BSER. The industry urged the agency to consider the sector as inter-connected rather than comprised of discrete power plants. It highlighted the efficacy of fuel-switching to natural gas, and increasing

renewable energy, among other things, to reduce emissions. These measures were sufficiently measurable and enforceable that the industry sought recognition for them as compliance options. The industry recognized the limited potential of at-the-plant efficiency upgrades to reduce emissions. And it requested maximum flexibility for states and companies through the use of trading, a broad scope of creditable compliance actions, and extended compliance periods. While the agency must reject the legal theory that it can only define the BSER based solely on measures that are integrated into the design and operations of the facility, these technical and policy suggestions from the industry are found reflected in the agency's final rule, and support the reasonableness of the EPA's choices.

VII. Division of Responsibilities under 111(d)

This section briefly summarizes the key determinations in this rulemaking under section 111(d), including the EPA's determination of the best system of emission reduction (BSER), the identification of the source subcategory-specific emission performance rates, and the state-level rate-based and mass-based CO_2 goals; the states' establishment of the standards of performance and submission of state plans; and the EPA's promulgation of standards of performance in a federal plan, under certain circumstances. In summarizing these determinations, this section highlights the respective roles of the EPA and the States.

A. The Determination of the BSER

For present purposes, the initial regulatory determination under CAA section 111(d)(1) is the BSER. As we explain in section V.B.1 of the preamble, the statute clearly gives the EPA the authority to determine the BSER. Section 111(a)(1) defines "standard of performance" as a standard for emissions that "reflects the degree of emission limitation achievable through the application of the best system of emission reduction … the *Administrator* determines has been adequately demonstrated" (emphasis added). Thus, we disagree with commenters who contend that the states, and not EPA, have that authority. The Administrator, under both 111(b) and (d), determines the BSER and the degree of emission limitation achievable through the application of the BSER, pursuant to section 111(a)(1).[33] As discussed below, states establish standards of

[33] The legislative history confirms that the Administrator determines the BSER. Congress revised section 111(d)(1) in the 1977 CAA Amendments to provide that state plans must establish "standards of performance" (in lieu of emission standards, under the 1970 CAA Amendments). According to the House Committee Report:

> This section is also intended to clarify the basis for standard-setting for existing sources under section 111(d) of the Act. Under the committee bill, the standards in the section 111(d) State plan would be based on the best available means (not necessarily technological) for categories of existing sources to reduce emissions. *The Administrator would establish guidelines as to what the best system for each such category of existing sources is.* However, the State would be responsible for determining the applicability of such guidelines to any particular source or sources.

H. Rep. 95-294 at 195, reprinted in 1977 CAAA Legislative History ("1977 LH") at 2662 (emphasis added). The reference to "guidelines" should be taken to be a reference to the

performance under section 111(d)(1), which is in contrast to the Administrator's authority to establish standards of performance under section 111(b). But section 111(d) does not alter section 111(a)(1)'s delegation of the determination of the BSER to the Administrator of the EPA.[34]

The language of section 111(a)(1) is also clear that after determining the BSER, the EPA is authorized under the CAA and the implementing regulations, as an integral component to setting emission guidelines, to determine the resulting emission limitation from the BSER. Specifically, the definition of a "standard of performance" under section 111(a)(1) is "a standard for emissions … which reflects the degree of emission limitation achievable through the application of the [BSER]." Because the purpose of the BSER is to determine the amount of emissions to be reduced and because the EPA determines the BSER, it is reasonable to interpret section 111(a)(1) to authorize the EPA to determine "the degree of emission limitation achievable" from the BSER.[35] Thus, in general, under section 111(a)(1), following the

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emission guidelines that the EPA described in the 1975 framework regulations under section 111(d).

[34] The Administrator's obligation to determine whether the best system of emission reduction is adequately demonstrated in inextricably connected with the determination of the best system of emission reduction itself. This is so because of EPA's obligation to substantively evaluate the BSER, which may include a review of technical literature, test data, prototype testing, and the predictions and guarantees of equipment manufacturers (among other qualitative and quantitative methods of review). *See, e.g., Essex Chem. Corp. v. Ruckelhaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974). By requiring EPA to determine the BSER, Congress intended to establish a national baseline for regulated sources. In the Clean Air Act Amendments of 1970, Congress was particularly concerned with "efforts on the part of States to compete with each other in trying to attract new plants and facilities without assuring adequate control of extra-hazardous or large-scale emissions therefrom." H. Rep. No. 91-1146, Reporting on H.R. 17255, p. 893 (Jun. 3, 1970). Providing states with an exclusive role in setting standards of performance could lead, Congress found, to pollution havens. Those same concerns apply to existing sources in the utility power sector today. For example, power companies and power system planners typically operate across large regions and make investment decisions across a diverse portfolio of assets that may be located in different states. These decisions often account for differing state and local requirements and incentives—retiring facilities in certain states and building or acquiring facilities in other states. Accordingly, uniform guidelines established by EPA will assure adequate minimum standards across the nation while still affording states with the flexibility to account for local conditions.

[35] That the EPA has authority to determine "the degree of emission limitation achievable through the application of the [BSER] is further supported by the fact that the EPA is authorized to review state plans to determine whether they are "satisfactory," under section 111(d)(2). To determine that the plans are "satisfactory," the EPA must be assured that the plans achieve at least the amount of emission limitation that application of the BSER would achieve. Interpreting section 111(a)(1) to authorize the EPA to determine "the degree of emission limitation achievable through the application of the [BSER]" is consistent with the EPA's review authority over state plans.

determination of the BSER, the EPA has the authority to identify the amount of emission limitation that reflects the application of the BSER to the affected sources.

Under the CAA, an "emission limitation" is amenable to expression as a quantity, rate, or concentration of emissions of air pollutants. In the Clean Power Plan, the emission limitation is expressed as the source subcategory-specific emission performance rates for the affected EGUs. Source subcategories in this context refers to fossil steam units and stationary combustion turbines. Thus the emission limitation is expressed as two rates in pounds of CO_2 per megawatt-hour of electrical generation output, one rate for steam electric units and one rate for stationary combustion turbines. (The CO_2 emission performance rates may also be referred to in the emission guidelines as the emission performance level or levels. As discussed in the following section, the emission performance rates are to be distinguished both from the state goals and from standards of performance.[36]) As discussed below, the agency is providing flexibility to allow states to demonstrate an equivalent level of emission performance through several design options for state plans.

These emission performance rates reflect the required emission performance level for all the affected sources. Because the EPA has determined these rates to be achievable, the States in submitting approvable plans must demonstrate that they will be met. This is consistent with the agency's longstanding view of its role in determining the BSER. Some "substantive criterion" must be available to govern the Administrator's review of state plans. 40 FR 53340, 53342 (Nov. 17, 1975). While the BSER as determined in the emission guidelines "will not have the purpose or effect of national emission standards" directly applicable to sources, the agency has long believed that "it is desirable (if not legally required) that the criteria [for approvability of state plans] be made known in advance to the States, to industry, and to the general public." *Id.* at 53343. *See also* 40 CFR 60.22(b)(3) (emissions guidelines will contain "information on the degree of emission reduction which is achievable with each system"); *id.* 60.25(a) (requiring states to submit "correlated" data "presented in such a manner as to show the relationship between measured or estimated emissions and the amounts of such emissions allowable under applicable emission standards").

In this rulemaking, after the EPA determined the BSER as the building blocks, the EPA then applied the building blocks to the source subcategories on a region-by-region basis. This allows us to identify the two source subcategory-specific emission performance rates in the region where application of the building blocks produced the least stringent rates. The EPA selected those least stringent rates as the two nationally uniform source subcategory-specific emission performance rates in order to ensure achievability and enhance flexibility nationwide. We discuss in more detail the legal authority to take this approach (applying the BSER on a regionwide basis, and determining nationally uniform emission levels) in Section V.A.3.e-f of the preamble.[37] These source subcategory-specific emission performance rates are, in essence,

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[36] "Emission standard" is the term found in the implementing regulations for section 111(d), and for our purposes, is synonymous with "standards of performance."

[37] We note that this regionalized approach differs from the proposal, where we applied building block 2 on a state-by-state basis. This had the unintended consequence of creating an unacceptable degree of inequity between sources in different states. In response to the many

the arithmetic expression of the BSER as applied to the two source subcategories on the basis of the least stringent region, which are then applied to the other regions. While they constitute the "degree of emission limitation achievable," and inform the agency's review of state plans for approvability, they are not, as described further below, binding in-and-of-themselves.

B. The Calculation of the State Goals

Once the EPA determined the BSER and the degree of emission limitation achievable, the agency translated the source subcategory-specific emission performance rates into the state-by-state, state-level rate-based and mass-based CO_2 goals. As we explain in Section VII of the preamble, these state goals inform the agency's review of state plans for approvability. However, these state goals are not binding or enforceable in and of themselves. Rather, they are the application of the source subcategory-specific emission performance rates to the mix of affected EGUs on a state-by-state basis. Thus, they are another arithmetic expression of the BSER, in this case as applied to the mix of affected EGUs in each state.

Just because the goals are not binding in the sense of being enforceable against the states or sources, does not mean a state is free to ignore them. To do so would be to invite the EPA's disapproval of that state's plan. The goals are a type of accounting device, that is, they are part of the methodology for assuring that if states adopt standards of performance that differ from the source subcategory specific emission performance rates, the states will be able to assure that they are obtaining the same emission performance level as the application of the BSER to their sources would require. The ability to use accounting metrics to determine equivalent levels of stringency is provided for, and wholly consistent with, the framework regulations of subpart B, which provide that an emission guideline is to contain information 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." 40 CFR 60.22(b)(5) (emphasis added).

The state goals represent a statewide translation of the subcategory-specific emission performance rates. They do not impose an obligation directly on states. The EPA agrees with commenters who say that the states, as states, are not the obligated parties for compliance with emission reduction requirements under section 111. The ultimate enforceable regulatory obligation under the Clean Power Plan, as under all section 111(d) emission guidelines, must fall on the affected sources themselves, here, the affected EGUs.

We disagree with commenters who consider the state goals to be binding in and of themselves and who then assert that the EPA does not have the authority to set binding state goals. This is a misunderstanding of the nature of the state goals as an accounting device that aids in the review of submitted state plans for approvability. Although the goals are not binding, they will inform the agency's substantive review of state plans for satisfactoriness. Given that the EPA has determined the degree of emission limitation achievable, state plans that fail to meet

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adverse comments we received on these state-by-state inequities, as well as comments noting that the approach failed to reflect the nature of the interconnected grid, we modified our approach from the proposal and agree that a regionwide approach is more appropriate.

these levels of emission reduction would be proposed for disapproval through a disapproval process that would include notice and opportunity for public comment. Nonetheless, failure to submit an approvable state plan is not a sanctionable violation of the Clean Air Act. It simply means the agency will have the responsibility to develop a federal plan for the affected EGUs in that state.

The agency recognizes that the goals for each state may vary to some degree, but this is a natural and unsurprising consequence of the application of the emission performance rates to each state's unique mix of affected EGUs. The variation in state goals has been substantially reduced in the final rule as compared to the proposal, in part to respond to the many adverse comments that this variation produced an unacceptable degree of inequity among sources in different states. The level of variation is minimized in the final rule.

We note that in the final rule, the agency is allowing the states important flexibilities with respect to meeting their goals: States utilizing early action programs to achieve reductions prior to the start of the interim period may qualify for matching credits or allowances from the EPA that increase the overall size of a mass budget or the overall pool of emission rate credits. States may set their own "steps" in the interim period to allow for relatively greater emissions earlier and relatively lower emissions later (in effect, allowing a form of emissions borrowing), so long as the interim performance level is achieved. Beyond limited circumstances expressly provided in the guidelines, the EPA is not authorizing states to set less stringent standards of performance for their sources in such a way that the overall state goal goes unmet.

Some commenters stated that this exceeds the proper scope of the EPA's authority because it sets binding, inflexible emission rate limits in the aggregate for all of a state's affected EGUs. Commenters said that under the proposal, once these "goals" are finalized, states will have no authority to change them, despite section 111(d)'s express grant of authority to the states, not EPA, to establish standards of performance and to consider factors such as the remaining useful life of sources in establishing standards of performance.

These comments are premised on a legal view that the statute unambiguously requires the EPA to allow states to reduce the stringency of standards of performance below emissions performance levels the EPA determined were achievable. The agency disagrees with these commenters. The state must establish the standards of performance for their sources in a manner consistent with the emission guidelines, and the standards are ultimately subject to the agency's substantive review of a state plan for satisfactoriness under section 111(d)(2)(A). States plans that do not meet the level of stringency the agency believes is achievable for the sources in that state can be disapproved. This comports with the agency's longstanding view that its review of state plans under section 111(d) is substantive. The agency agrees with commenters to the extent that the statute affords EPA the discretion to decide in certain rules that a downward variation in emissions performance for some affected sources in a state under section 111(d) could be authorized. The implementing regulations provide this authority at 40 CFR 60.24(f). But this does not mean that for a particular emissions guideline for a particular pollutant from a particular category of sources, the agency cannot reasonably decide that such downward variations are

unwarranted. That is the case here, as we explain in the section of the preamble and this Legal Memorandum concerning the remaining useful life provision of section 111(d)(1).[38]

The alternative suggested by commenters would leave the agency powerless to prevent an unbounded loosening of stringency of national air pollution control under section 111(d) by the states. As we describe in the preamble in Section V, Congress intended that the CAA be a comprehensive vehicle for regulating air pollution, and enacted this provision to ensure there was no gap in the statute through which serious air pollution problems might go unaddressed. Allowing the states to have the degree of unreviewable discretion that the commenters urge means that the states could functionally ignore national air pollution control objectives and leave the federal government without any recourse to respond. *See* 40 FR at 53343.

C. The Establishment of Standards of Performance and Design of State Plans

Following the promulgation of the emission guidelines, the scene shifts to the States. The States are required to submit state plans that take the emissions standards approach or the state measures approach, and that meet the requirements of the guidelines. The emission guidelines give states a wide range of choices in the design of their plans.[39] They may impose the sub-categorized emission performance levels on their sources as rate-based emission standards, or they may take one of several options to achieve an equivalent result, any of which may be preferable for a particular state given its unique circumstances. They could impose the single, combined state rate on all affected EGUs in their state. They could use a mass-based program using the mass budget that the agency determined in the final rule represents an equivalence in performance to the sub-categorized emission rates.

The above-described set of requirements and calculations in the emission guidelines does not mean that the EPA is requiring that sources or states implement the BSER. The agency's requirement is that state plans meet emission guidelines requirements for approvability, including most importantly, the achievement of the emission performance levels. The EPA is not requiring the implementation of the building blocks or any other type of specific controls. In fact, under section 111(b)(5), where the EPA imposes standards of performance on new sources, the EPA is explicitly precluded from requiring any particular type of emission control, including the BSER. Rather, the "degree of emission limitation" determined by the BSER sets the standard of performance, but sources remain free to determine how they will meet the standard. There is no comparable provision to 111(b)(5) for existing sources under section 111(d), but the notion that the BSER is not specifically required is consistent with this statutory construct. When we promulgate a 111(d) rule determining an add-on technology like a scrubber to be the BSER, we

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[38] The implementing regulations make clear that the agency is not bound to permit states to set less stringent standards in all cases, particularly where the pollutants pose a risk to public health. 40 CFR 60.24(c), (f) Paragraph (f) expressly provides that specific emission guidelines may not allow for its use. *See id.* ("Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities…").

[39] The agency recognizes states' reserved authority under section 116 of the CAA to implement more stringent standards on their sources. The agency also recognizes that states may find it advantageous to enact complementary programs, entirely outside of the CAA, that help make the state goals even more cost-effective to achieve.

do not require that the sources or states implement that add-on technology; rather, we require only that the states submit plans that achieve the emission performance level of the BSER that we have determined. In some past rules, as a practical matter, it may be that for a given type of pollutant or source category, a particular technology the EPA identified as the BSER is the only available means of achieving the performance standard. But this is not the case for this rule.

Thus, we disagree with commenters who stated that we are improperly requiring states to implement the building blocks, such as by ordering re-dispatch to natural gas-fired units, or ordering the construction of renewable energy projects. The premise of these comments is incorrect. Nowhere in the final emission guidelines are such actions directed or ordered to occur. Furthermore, under this rule, the EPA would not exert enforcement authority over entities other than the affected EGUs and their owners and operators, in order to enforce the emission standards applicable to the affected EGUs set in a state plan (or federal plan if necessary). This rule does not mandate or authorize that state renewable energy or energy efficiency programs become federally enforceable under the CAA.

As a practical matter, the states do not have to implement the BSER or require that sources implement the BSER, and sources do not have to implement the BSER to achieve the emission performance levels; even so, we recognize that some sources will, in fact, take actions that reflect or resemble the implementation of the building blocks. But as we explain in Section V.B of the preamble, states and sources have many choices other than the building blocks. They can choose to get emissions reductions by implementing demand-side-energy efficiency (DS-EE) projects and programs; co-fire with natural gas, re-power with natural gas, or take other measures that we describe in the preamble and that others have described.

We expect that some sources will implement measures that reflect or resemble the building blocks. These measures met the requirements of being the “best” system of emission reduction that is adequately demonstrated, taking into account costs and other factors. Thus, it is entirely reasonable to anticipate that they will be used in practice. But commenters are incorrect in asserting that the EPA is requiring states and sources to implement the building blocks or reduce generation, or that states and sources have no choice but to implement the BBs or reduce generation. As discussed above, states and sources have choices as to the amount or degree to which they implement the BBs and a high degree of flexibility to use other methods.

All of this is consistent with how EPA has promulgated section 111 rules in the past. Sources do not have to implement the BSER, although in many cases they can be expected to do so. For this rule, we expect greater use of alternatives to the BSER measures than in other rules, in part because DS-EE is a relatively inexpensive means of obtaining emission reductions from the affected EGUs.

D. The Establishment of Standards of Performance in a Federal Plan

If a state does not submit a state plan or the EPA disapproves a state plan submittal, the EPA will promulgate a federal plan that will impose the standards of performance (in implementing regulations referred to as “emission standards”) on affected EGUs, and provide for their implementation and enforcement. The EPA is proposing a federal plan to demonstrate how this can be done. The federal plan will also serve as a model rule for states to adopt or tailor for

use in their own state plans. Even where the EPA is directly implementing the standards of performance in a federal plan, however, the agency will not, and need not, attempt to order sources to implement the measures that comprise the BSER. Rather, the agency would set emission standards for each of the affected EGUs in the federal-plan state, provide mechanisms for their implementation and enforcement, and otherwise leave to the owners and operators of the affected EGUs the decisions about what measures they want to take to comply with the emission standard. Though the emission standards will be federally enforceable, as under a state plan, sources may achieve them through implementation of measures in the BSER, or any other method. The state and its officials do not necessarily need to play any role in the implementation of a federal plan. However, the agency may delegate administration of aspects of the program or may approve partial state plans for portions of the otherwise-federal program. These mechanisms and other facets of implementation will be set out in greater detail in the preamble and other supporting documentation to the proposed federal plan.

In the context of a federal plan, it becomes easier to see why the question whether the EPA would have the authority to directly order the implementation of the measures in the building blocks is not only not relevant, but represents a categorical misunderstanding of the nature of the BSER in relation to the imposition of standards of performance. Commenters on the proposal asserted that the BSER cannot include building blocks 2, 3, or 4 because the EPA may include in the BSER only controls that the EPA has the authority to implement or enforce, and, the commenters continue, the EPA does not have the authority to implement or enforce these building blocks. We disagree with these comments. First, the EPA has determined not to finalize building block 4 as a component of the BSER. Additionally, the authority or practical ability of the EPA to implement or enforce the BSER itself is irrelevant and based on a false premise. To illustrate this, by the same token, the EPA could not enforce many logistical aspects of a control requirement such as a scrubber – for instance, the EPA does not have the authority to order the creation of companies that manufacture scrubbers, or order their construction or delivery on a certain schedule. The EPA need not have before it at the stage of determining the BSER all of the information regarding manufacturing, transportation of parts, or other logistical requirements to ensure that each scrubber gets constructed and delivered to a source. Nonetheless, the agency can determine the BSER premised on a reasonable assumption that all of those things can actually happen.

What is relevant is that the control requirements that the EPA identifies meet the statutory considerations to qualify as the BSER, which include that the owners or operators of the affected sources be able to implement the control measures and achieve their emission limits through those control measures. As we discuss elsewhere, that is the case for all of the building blocks in the final rule. Thus, the EPA can reasonably determine that the federally enforceable emission standards that would be set in a federal plan, just as in a state plan, are achievable by the affected EGUs and will be met either through the measures in the building blocks or, if the affected EGUs so choose, through other measures that contribute to its compliance. The agency will provide for the implementation of the standards of performance via the same types of regulatory mechanisms being made available to states in the emission guidelines.

E. Summary of the Determinations Under section 111(d) and Respective EPA and State Roles

Through the process of section 111(d), the EPA regulates air pollutants from source categories of existing sources, in this case, CO_2 from certain fossil fuel-fired EGUs. This regulation necessarily has impacts on the source category, which in this case is a key part of the broader electric utility power sector. But this does not mean that the EPA is overstepping its authority. The fact that the EPA has the authority to determine the BSER means that the EPA has the authority to determine the degree of emission limitation achievable, which in the Clean Power Plan is expressed as the CO_2 emission performance rates. The agency has translated these into a set of state goals that each reflect an emission performance level that is equivalent to the emission performance rates. The agency's emission guidelines set forth these performance levels, along with other requirements, as the minimum requirements for states to meet in order to have an approvable state plan. If a state fails to submit an approvable plan, the EPA will implement a federal plan imposing emission standards for the affected EGUs in that state.

Contrary to the views of some commenters, the Clean Power Plan does not usurp state authority over the electric utility sector or other traditional areas of state regulation. As in many other areas of environmental law, the EPA has set minimum federal requirements for a class of polluting facilities, and states have the opportunity to design a program to meet those requirements, or go beyond them if they so choose. In this way, the Clean Power Plan is fully consistent with the principles of cooperative federalism that underlie the Clean Air Act and that are incorporated into section 111 and maintains a proper balance of roles between the federal government and the States.

VIII. Authority of the Administrator to determine State Plans to be "Satisfactory"

Section 111(d)(2)(A) authorizes the EPA to promulgate a federal plan for any State that "fails to submit a satisfactory plan" establishing standards of performance under section 111(d)(1). This also provides the standard by which the EPA reviews state plan submittals: such submittals must be "satisfactory." The reason is structural: Any other standard than "satisfactory" for the EPA's action on a plan submittal would leave a grey area between submittals that are disapproved under the other standard and the EPA's federal plan authority, which is based on whether a plan is "satisfactory." In other words, the standard triggering the EPA's federal plan authority must be identical with the standard for action on state plans.

The relevant dictionary meaning of "satisfactory" is "fulfilling all demands or requirements." The American College Dictionary ("ACD") 1078 (C.L. Barnhart, ed. 1970); *see also* Oxford English Dictionary ("OED") (2d and 3d ed.; online version) ("To answer the requirements of (a state of things, a hypothesis, etc.); to accord with (conditions). †Also *rarely* of a person: To fulfil the requirements of."). The related word "satisfy" (both originate from the Latin "satisfacere") can mean "to fulfill the requirements or conditions of." ACD at 1078. Thus, the natural interpretation of "satisfactory plan" is a section 111(d) plan that meets the conditions or requirements of the emission guidelines.

Furthermore, section 111(d)(2) states that the EPA shall have the "same authority to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as [the EPA] would have under section 7410(c) of this title in the case of failure to submit an implementation plan." Because 111(d)(2) gives the EPA the "same" authority as EPA would have under section 110(c), the meaning of "satisfactory" should be informed by the structure of

110(c). In other words, EPA should have the same authority, structurally, as EPA does under 110(c).

When section 111 was added to the CAA, section 110(c) read:

> The Administrator shall, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth an implementation plan, or portion thereof, for a State if—
> (1) the State fails to submit an implementation plan for any national ambient air quality primary or secondary standard within the time prescribed,
> (2) the plan, or any portion thereof, submitted for such State is determined by the Administrator not to be in accordance with the requirements of this section, or
> (3) the State fails, within 60 days after notification by the Administrator or such longer period as he may prescribe, to revise an implementation plan as required pursuant to a provision of its plan referred to in subsection (a)(2)(H).

Clean Air Amendments of 1970, Pub. L. 91-604, § 4, 84 Stat. 1682 (1970). Subsections 110(c)(1) and (c)(3) correspond to failure to submit a plan or revised plan, respectively, and do not set a standard for a submitted plan. On the other hand, subsection 110(c)(2) does set a standard: under subsection 110(c)(2), State submissions must "be in accordance with the requirements" of Section 110.[40] Thus, the natural interpretation of "satisfactory" described above is consistent with this: if EPA can issue a FIP after determining a SIP is not in accordance with the requirements of section 110, then under section 111(d)(2), the EPA can issue a federal plan if the state plan is not in accordance with the requirements of section 111(d)(1). In both cases, it is understood that regulations the EPA issues specifying requirements under the relevant sections (e.g. subpart B and these emission guidelines under section 111(d)(1)) are to be considered "requirements of" the relevant section. Any other outcome would eviscerate the EPA's authority under sections 301(a) and 111(d)(1) to issue binding regulations.

In its current form, as amended by the 1990 Clean Air Act Amendments, the corresponding portion of section 110(c)(1) (i.e. the portion that gives the EPA FIP authority when the state submits a SIP, but it is deficient) does not set a standard for submitted SIPs. Instead, the corresponding portion, subsection 110(c)(1)(B), is conditioned on the EPA's disapproval of a SIP submittal in whole or part. The substantive standard for the EPA's action on a SIP submittal is set in section 110(k)(3): it must "meet[] the applicable requirements of [the Act]." (*See also* section 110(*l*): SIP revisions cannot "interfere with … any other applicable requirement of [the Act].") It should be noted that, in this context, "meet" is synonymous with the connotation of "satisfy" mentioned above: "to satisfy the requirements of (a particular case, a deadline, etc.)." OED. Thus, the current form of section 110(c) confirms the above interpretation of "satisfactory": for a section 111(d)(1) state plan to be "satisfactory," it must meet the applicable requirements of the Act, including and in particular the applicable requirements of section 111(d)(1), subpart B, and the EPA's emission guidelines. And the language, "applicable requirements of the Act," in section 110(k)(3) confirms that the plan must meet the requirements of section 111(d)(1) and any other applicable section of the Act, and any regulations the EPA

[40] In addition, the 1970 version of section 110(a)(3) provided a positive (i.e. not in the context of a disapproval and FIP) standard. *See Train v. NRDC*, 421 U.S. 60 (1975).

promulgates (i.e. subpart B and the emission guidelines) under section 111(d)(1) or section 301 that apply.

Thus, based on the dictionary meaning of "satisfactory" and the structure of the Act, Congress has spoken directly to the issue. "Satisfactory" means "meet all applicable requirements of the Act." But even if a court found "satisfactory" ambiguous with respect to this issue, EPA's interpretation of "satisfactory" would be reasonable. There is nothing in the legislative history to suggest that section 111(d)(1) state plans should be reviewed by the EPA by any other standard, and as described above, it is reasonable that the EPA's authority to issue regulations under sections 111(d)(1) and 301 should have actual effect in the EPA's action on state plans.

Finally, courts have routinely referred to "satisfactory" plans or SIPs as a shorthand way of summarizing the approval/disapproval process under section 110(k). *See, e.g., Vigil v. Leavitt*, 381 F.3d 826, 830-831 (9th Cir. 2004) ("In the event that a state does not submit a SIP or does not submit a satisfactory plan within the specified time, the EPA Administrator shall promulgate a federal implementation plan"); *NRDC v. EPA*, 22 F.3d 1125, 1134-35 (D.C. Cir. 1994) (discussing conditional approvals as "an alternative to disapproving substantive, but not entirely satisfactory, SIPs submitted by the statutory deadlines"); *Illinois EPA v. U.S. EPA*, 947 F.2d 283, 285 (7th Cir. 1991) (describing SIP negotiations that "failed to produce a satisfactory SIP" and the consequential SIP disapproval); *New Mexico Environmental Improv. Div. v. Thomas*, 789 F.2d 825, 833 (10th Cir. 1986) (explaining that the "EPA reasonably concluded that a satisfactory SIP in terms of section 7502 requirements had never been submitted"); and *Air Pollution Control Dist. v. U.S. EPA*, 739 F.2d 1071, 1075 (6th Cir. 1984) (explaining the EPA's authority to devise a FIP "[i]f a state fails to submit a satisfactory plan").

Accordingly, in light of the EPA's authority under section 110(c), it is mandated, or at the least reasonable, that the term "satisfactory plan" should be interpreted to mean a plan that meets all applicable requirements of the Act, including but not limited to section 111(d), subpart B, and these emissions guidelines. For structural reasons, it is also the case that the EPA not only has the authority to, but in fact <u>must</u> approve a plan that meets all applicable requirements of the Act.[41] Although there is no case law specifically on the standard of review of a section 111(d)(1) state plan or the EPA's duty to approve satisfactory plans, as explained above, the EPA's action on a 111(d)(1) state plan is structurally identical to the EPA's action on a SIP. Under section 110(k)(3), EPA must approve a SIP that meets all requirements of the Act. *See Train v. NRDC*, 421 U.S. 60 (1975) (discussing the 1970 version of the Act); *Virginia v. EPA*, 108 F.3d 1397, 1408-10 (D.C. Cir. 1995) (discussing the 1970, 1977, and 1990 versions). Therefore, the EPA must also approve section 111(d)(1) state plans that meet all applicable requirements of the Act (i.e., are "satisfactory") – any other result would leave a void where the EPA did not approve a satisfactory plan, but could not promulgate a federal plan.

Based on the reasoning of *Train v. NRDC* and the language of sections 110 and 116 of the Act, the U.S. Supreme Court in *Union Elec. Co. v. EPA*, 427 U.S. 246 (1976), held that the

[41] Of course, this does not mean that the EPA lacks authority to determine what requirements should apply to those plans, as the EPA is doing in these emission guidelines. See the discussion in the previous section.

EPA could not disapprove a SIP on the basis that the plan required technologically infeasible controls that might force facilities to shut down. The Court noted that the most natural reading of section 110 did not preclude the state from imposing requirements that might reduce emissions more than necessary to attain the national ambient air quality standards ("NAAQS"). *Id.* at 262-63. The Court also noted that section 116 specifically provided that States could adopt emission standards that are more stringent than national standards. *Id.* In response to the argument that such more stringent emission standards could not be part of the SIP, the Court reasoned that it would be difficult for the Administrator to determine what emission standards would precisely bring an area into attainment but no more, and pointless for States to maintain two sets of emission standards (one federally enforceable and one not). *Id.* at 264. Thus, the Court held that "States may submit implementation plans more stringent than federal law requires and that the Administrator must approve such plans if they meet the minimum requirements" of the Act. *Id.* at 265.

Both *Train* and *Union Electric* set out a general principle that the EPA cannot "question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies" the requirements of the Act.[42] *Train*, 421 U.S. at 79. "[S]o long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation." *Id.*; *accord Union Elec.*, 427 U.S. at 266 ("So long as the national standards are met, the State may select whatever mix of control devices it desires, and industries with particular economic or technological problems may seek special treatment in the plan itself.") (citing *Train*, 421 U.S. at 79). This State discretion includes the discretion to "submit implementation plans more stringent than federal law requires." *Id.* at 265. In the section 110 context, the critical cooperative-federalism inquiry is whether the EPA has provided the States "real choice" in how to develop SIPs that meet CAA requirements.[43] The relevant precedents do not stand for the broader proposition—suggested by some commenters—that states have unlimited discretion in developing SIPs, or that EPA is prohibited from interpreting CAA requirements or reviewing SIP submissions for compliance with CAA requirements. To the contrary, the Supreme Court recently affirmed EPA's authority to reasonably interpret the CAA requirements applicable to SIPs, and to evaluate the sufficiency of SIPs against those requirements.[44]

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[43] *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1047 (D.C. Cir. 2001) (citing *Virginia*, 108 F.3d 1397, 1406, 1410 (D.C. Cir. 1997) (explaining that although states have discretion in developing SIPs under section 110, that discretion is cabined by the "extrinsic legal constraints" in the CAA). By contrast, the EPA may not legally or functionally require states to include "specific" control measures in a SIP. *See, e.g.*, *Train*, 452 U.S. at 79 (the EPA "is relegated by the [1970] Act to a secondary role in the process of determining and enforcing the *specific, source-by-source emission limitations* which are necessary if the national standards it has set are to be met") (emphasis added); *Virginia v. EPA*, 108 F.3d 1397, 1415 (D.C. Cir. 1997) (holding that under section 110, the EPA cannot functionally require states to "adopt[] *particular* control measures" in a SIP but must rather ensure that states have a meaningful choice among alternatives); *Michigan v. EPA*, 213 F.3d 663, 687 (D.C. Cir. 2000) (emphasis added) (holding that, in context of section 110 emission budget trading program, EPA's emission budgets must provide "*the covered states real choice with regard to the control measure options available to them* to meet the budget requirements") (emphasis added).

[44] *See EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1593 (2014) (citing *Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837 (1984)); *see also Mich. Dep't of Envtl. Quality v. Browner*, 230 F.3d

No Court has had occasion to consider whether the general principles of *Train* and *Union Electric* should apply to emission guidelines for section 111(d) state plans, but to the extent those principles do apply here, these guidelines satisfy them. The EPA has given States maximum flexibility to achieve the rate-based or mass-based goals, or (should a State adopt the performance rates) to provide ERCs from various types of measures. Numerous measures that reduce CO_2 emissions from affected EGUs and that are otherwise consistent with the requirements of these guidelines (such as enforceability) and the purposes of section 111(d)(1) may be credited. Furthermore, a state is free to reallocate the burdens of these guidelines among affected EGUs by imposing emission standards that vary from EGU to EGU. Finally, the possibility of interstate trading using fungible allowances or ERCs does not impermissibly constrain a state's authority under section 116 to impose more stringent emission standards, as a state is free to require affected EGUs to hold more allowances or ERCs, or to emit less CO_2 than is required under these guidelines. This significant flexibility allows states to take local circumstances and state policy goals into account in determining how to reduce emissions from their affected sources, provided the plan meets minimum federal requirements. Accordingly, states have real choice to develop specific measures in state plans in way that meets the broader requirements of section 111(d) and this rule. Far from unlawfully encroaching upon state discretion, the federal-state balance in this rule is a paradigmatic example of cooperative federalism in pollution control laws.

IX. "Remaining Useful Life" Provision of Section 111(d)(1)

This section discusses our interpretation of the "remaining useful life" provision of section 111(d)(1) and our application of that interpretation to these emission guidelines.

The second and last sentence of section 111(d)(1) provides: "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." This portion of the legal memorandum examines: A) remaining useful life in the context of the implementing regulations in 40 CFR part 60 subpart B; B) the legislative history of the remaining useful life provision; C) the meaning of certain terms in the provision; and D) the EPA's interpretation of similar provisions in the Act's visibility program (including some relevant case law). We conclude that (and as supported by the preceding four discussions), these emission guidelines reasonably interpret the remaining useful life provision, and we conclude that, on the record before us, these emission guidelines reasonably permit states to take into consideration remaining useful life and other factors. We also review two U.S. Supreme Court opinions examining variances under the Clean Water Act and discuss their relevance to remaining useful life as implemented by these emission guidelines.

A. Implementing Regulations in Subpart B

Some commenters argued that, due to the remaining useful life provision, these guidelines impermissibly require state plans to achieve the rate-based or mass-based goals. In

181, 184–85 (6th Cir. 2000) ("Although states are given broad authority to design programs, the EPA has the final authority to determine whether a SIP meets the requirements of the CAA.").

these commenters' views, if a State relaxes an emission limitation for one affected EGU in order to take into consideration remaining useful life, the State should not be required to increase the stringency of other emission limitations to maintain the goal. The implementing regulations in subpart B contemplate that states, in certain limited circumstances subject to EPA approval, may impose emission standards on particular facilities that are less stringent than generally required by emission guidelines. *See* 40 C.F.R. § 60.24(f). We therefore start with a discussion of those regulations.

The EPA first promulgated the subpart B regulations in 1975. 40 Fed. Reg. 53,340 (Nov. 17, 1975). At that time, section 111(d)(1) stood as enacted by the 1970 Clean Air Act:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes emission standards for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 108(a) or 112(b)(1)(A) but (ii) to which a standard of performance under subsection (b) would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such emission standards.

Pub. L. 91-604 § 4(a), 84 Stat. 1676, 1684. Thus, when the EPA first promulgated the subpart B regulations, there was no remaining useful life provision, and subsection 111(d)(1)(A) required states to establish "emission standards," not "standards of performance."

In proposing the subpart B regulations, the EPA stated: "It is the Administrator's judgment that section 111(d) permits him to approve State emission standards only if they reflect application of the best systems of emission reduction (considering the cost of such reduction) that are available." 39 Fed. Reg. 36,102, 36,102/1,2 (Oct. 7, 1974). Of particular relevance to remaining useful life, EPA went on to state:

> It is recognized, however, that application of such standards may be unreasonable in some situations. For example, to require that existing controls be upgraded by a small margin at a high relative cost may be unreasonable in some cases. The proposed regulations, therefore, provide that States may establish less stringent emission standards on a case-by-case basis provided that sufficient justification is demonstrated in each case.

Id. at 36,102/2. The EPA therefore proposed that the subpart B regulations should contain a variance provision. *See id.* at 36,104/2. In response to an adverse comment, the EPA in finalizing the regulations stated:

> Although section 111(d) does not explicitly provide for variances, it does require consideration of the cost of applying standards to existing facilities. Such a consideration is inherently different than for new sources, because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases. For these reasons, EPA believes the provision [§ 60.24(f)]

> allowing States to grant relief in cases of economic hardship (where health-related pollutants are involved) is permissible under section 111(d).

40 Fed. Reg. 53,340, 53,344/2 (Nov. 17, 1975). The EPA did not state that section 111(d) compelled the EPA to provide for variances, just that it was permissible. As promulgated in 1975, subsection 60.24(f) provided:

> On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> (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 or final compliance time significantly more reasonable.

Id. at 53,347/3. Thus, under the 1975 regulations, States had to demonstrate that a less stringent emission standard was warranted, and that demonstration and the resulting emission standard were subject to the EPA review and approval. *Id.* at 53,348/2, 3. Despite the adverse comment, the promulgation of 60.24(f) was not challenged.

As discussed in detail in the next section, Congress added the remaining useful life provision in the 1977 Amendments. The legislative history indicates that Congress was aware of the 1975 implementing regulations and, through the remaining useful life provision, addressed the concerns (particularly regarding unreasonably expensive retrofit controls) that the EPA expressed when promulgating 60.24(f). The EPA did not revise the implementing regulations after the 1977 Amendments, but the EPA did issue emission guidelines for certain source categories. *E.g.*, 45 Fed. Reg. 26,294 (Apr. 17, 1980) (primary aluminum plants). In responding to an adverse comment on the primary aluminum plant emission guidelines, the EPA stated: "The States may take into consideration the remaining useful life of a plant. Where a facility contains both old and new [reduction] cells, it may be reasonable to apply somewhat less stringent standards to the old." *Id.* at 26,295. Thus, the EPA thought that subpart B adequately addressed the remaining useful life provision for the purposes of that guideline, and was not challenged on that position.[45]

Some commenters argued that the 1975 regulations, having been promulgated prior to the 1977 Amendments, necessarily do not implement the remaining useful life provision. Based on the history of the 1975 implementing regulations presented here and the 1977 Amendments presented below, we think those comments are overstated; however, that disagreement is not

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[45] In that action, EPA determined that designated pollutant, fluoride, was welfare-related, *id.* at 26,296, which provided certain other flexibilities, *see* 40 C.F.R. § 60.24(d). Nonetheless, the use of the word "reasonable," which does not occur in 60.24(d), indicates that 60.24(f) might have applied.

necessary to our promulgation of these emission guidelines as we next explain. We did not reopen the implementing regulations in Subpart B for comment and, because we are not relying on them to implement the remaining useful life provision it is not necessary to respond to these commenters.

In 1995, the EPA added the prefatory phrase "Unless specified otherwise in the applicable subpart" to 60.24(f). The EPA was not challenged on that revision to subpart B, which now applies to emission guidelines issued under both sections 111(d)(1) and 129(b). On its face, the language now allows for other approaches to satisfying the remaining useful life provision. Thus, subpart B does not mandate the outcome that the commenters suggest, that States must be permitted to relax emission standards on particular affected EGUs on the basis of remaining useful life (or other factors) without requiring offsetting reductions from other affected EGUs. In fact, the EPA promulgated section 111(d)(1) emission guidelines, as part of the Clean Air Mercury Rule (CAMR),[46] that set mass-based statewide caps on mercury emissions from coal-fired electric utility steam-generating units. States either had to adopt an allowance-based trading program, or had to impose individual emission standards; in both cases, the statewide cap had to be met and could not be adjusted. Thus, under CAMR, the sort of adjustment that commenters argue is necessarily required in order to take into account remaining useful life was not allowed. In any case, these emission guidelines avail themselves of the possibility added in the 1995 revision to make the source-specific variance factors inapplicable. Instead, they satisfy the remaining useful life provision in other ways, as discussed in this section of the legal memorandum.

B. Legislative History

As mentioned above, the 1970 version of section 111(d)(1) did not contain a remaining useful life provision. The provision in subsection 111(d)(1) for state plans and the similar but not identical provision for federal plans in subsection 111(d)(2) were added to section 111(d) in the 1977 Clean Air Act Amendments. Pub. L. 95-95 § 109(b)(1), 91 Stat. 685, 699. The provisions first appeared in a House bill introduced in the 94th Congress. See H.R. 10498, § 111 (May 15, 1976), reprinted in A Legislative History of the Clean Air Act Amendments of 1977 ("1977 LH"), Environmental Policy Division, Congressional Research Service, Library of Congress, at 5961 (Aug. 1978, Serial No. 95-16). They were "intended to clarify the basis for standard-setting for existing sources under section 111(d) of the Act." H. Rep. to accompany H.R. 10498; 1977 LH at 6717.

In the 95th Congress, the House proposed a nearly identical bill to H.R. 10498, which included the same language on "remaining useful life." The House report accompanying H.R. 6161 even repeated the explanations stated in the House report accompanying H.R. 10498, see H. Rep. 95-264 at 195; 1977 LH at 2662. Also, H.R. 6161 added a new section on visibility protection, which required the consideration of the remaining useful life of any existing source subject to "best available retrofit technology" (BART) or "maximum feasible progress" (as

[46] CAMR was vacated by the D.C. Circuit on account of the EPA's flawed CAA section 112 delisting rule, although the court declined to reach the merits of the EPA's interpretation of CAA section 111(d). *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

enacted, "reasonable progress") requirements. See H.R. 6161, § 116 (May 12, 1977); 1977 LH at 2329.

According to the House report accompanying H.R. 6161,[47] the revisions to section 111 were also intended to clarify section 111(d):

> This section is also intended to clarify the basis for standard-setting for existing sources under section 111(d) of the Act. Under the committee bill, the standards in the section 111(d) State plan would be based on the best available means (not necessarily technological) for categories of existing sources to reduce emissions. The Administrator would establish guidelines as to what the best system for each such category of existing sources is. However, the State would be responsible for determining the applicability of such guidelines to any particular source or sources. The Administrator's guidelines must take into account the remaining useful life of existing sources. Unless the State decides to adopt and enforce more stringent standards, the State plan would be expected to take into account the remaining useful life of the source (or sources).

H. Rep. 95-294 at 195; 1977 LH at 2662.

From the perspective of remaining useful life, three things are worth noting about this passage. First, it adopts the term "guidelines" consistently with the EPA's usage of the term in the 1975 implementing regulations. This indicates that the remaining useful life provision was informed by those implementing regulations, including the EPA's intention in using the word "guideline" to indicate a rule that was not directly enforceable against affected sources, but that was binding on states in developing and submitting their plans. *See* 40 Fed. Reg. 53,340, 53,341/2 (Nov. 17, 1975). The sentence in the legislative history about states determining applicability is consistent with this: the guidelines are not directly applicable to a particular source, but the state plan does apply to particular sources within the guideline source category.

Second, because Congress recognized the EPA's interpretation in the implementing regulations and therefore expected the EPA's emission guidelines in general to set binding requirements for states, Congress in particular expected the EPA to set binding requirements for consideration of remaining useful life. This is clear from the sentence stating, "The Administrator's guidelines must take into account the remaining useful life of existing sources." It should also be noted that this sentence uses "life," not "lives"; thus, it was not expected that the EPA, in promulgating emission guidelines, would examine the remaining useful life of each particular source individually. Instead, the EPA should determine how remaining useful life should generally be taken into account for a particular source category.

Third, the House report states: "Unless the State decides to adopt and enforce more stringent <u>standards</u>, the State plan would be expected to take into account the remaining useful

[47] The Senate bill had no corresponding provisions, and the Senate concurred with minor amendments. H. Rep. 95-564 (conference report); 1977 L.H. at 510. Thus, the House report should be taken as the primary source of legislative history.

life of the source (or sources)." Thus, consistent with the statutory text, "in applying a standard of performance to any particular source," Congress intended that taking into account remaining useful life was not an avenue to avoid application of a standard of performance to a particular source, but instead a way to tailor to some extent (based on remaining useful life) the application of the standard to that particular source.[48] In other words, the remaining useful life provision does not provide an unmitigated ability for States to exempt their sources from standards of performance, particularly if such exemptions would lead to a failure to achieve the degree of emission limitation the EPA determined to be achievable when there is on the record no warrant for doing so.

This is consistent with the 1975 implementing regulations, which do not provide for an exemption, but instead provide for application of a less stringent standard based on certain factors. 40 Fed. Reg. 53,340, 53,347/3 (Nov. 17, 1975) (promulgation of 40 C.F.R. 60.24(f)). Thus, the interpretation of the provision here as not allowing for an exemption is consistent with those regulations.

The points above are general but consistent with the overall framework of section 111(d); a concrete concern of Congress addressed in the remaining useful life provision was the cost of retrofit technology at existing sources and the potential for other, more cost-effective means of compliance.[49] This can be seen in the legislative history in the broader context of the corresponding changes in the House bill to the provisions for new source performance standards. In the 1977 Amendments, Congress required that new sources install controls to reduce emissions, in lieu of reliance on cleaner fuels. A reason for this was to reduce demand by new sources for cleaner fuels, freeing up those fuels (which were perceived at the time to be relatively scarce) to be used by existing sources. H. Rep. 95-294 at 185; 1977 LH at 2652. For older and smaller existing sources, it might not be physically or economically feasible to install retrofit technology. By allowing those latter sources to comply through use of cleaner fuels, sources with "relatively short remaining useful lives" could stay in operation rather than shut down, and sources with small marginal revenues could avoid large up-front capital costs associated with retrofit controls. H. Rep. 95-294 at 186; 1977 LH at 2653.

This provides necessary context for the statement in the legislative history that "the standards in the section 111(d) State plan would be based on the best available means (not necessarily technological) for categories of existing sources to reduce emissions." H. Rep. 95-294 at 195; 1977 LH at 2662. Thus, in explicitly retaining the BSER as the standard for existing

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[48] As discussed below, there could be factual circumstances for a particular source category under which it might be reasonable for the EPA to interpret the remaining useful life provision as allowing states to impose no obligations for particular sources because of remaining useful life or other factors. However, those circumstances are not present here.

[49] As mentioned before, concern with the cost of retrofit controls was expressed by the EPA as a basis for the variance provision in the 1975 implementing regulations: "[C]ontrols cannot be included in the design of an existing facility and [] physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases." 40 Fed. Reg. 53,340, 53,344/2 (Nov. 17, 1975).

sources,[50] Congress made clear that the EPA was not obligated to base the BSER on control technology, but could nonetheless, for some source categories and some pollutants, reasonably do so after considering costs.

One other parallel context in the 1977 Amendments should be discussed. Congress added a new section to the Clean Air Act, section 169A, regarding protection of visibility in certain National Parks and Wilderness Areas. The definition of best available retrofit technology (BART) required states (or EPA in a FIP) to consider five specific factors, including the remaining useful life of the source and the costs of compliance.[51] While the legislative history does not discuss the remaining useful life factor in detail, Congress made clear that best available retrofit technology (BART) should not be required at all on sources built prior to 1962. H. Rep. to accompany H.R. 6161, 1977 LH at 2480; see also H.R. 6161, § 116, 1977 LH at 3237. Consequently, Congress provided an explicit exemption for these older sources. This exemption is instructive for two reasons. First, it shows that Congress was concerned primarily with the EPA requiring retrofit controls on older sources likely to have shorter remaining useful lives. Second, and more importantly, it shows that Congress viewed the consideration of "remaining useful life" to be something other than an exemption. Where Congress wanted to provide an exemption for certain sources from retrofit requirements, it did so explicitly. This is consistent with the legislative history for the section 111(d)(1) remaining useful life provision, which expressed a concern that older sources with "relatively short remaining useful lives" might prematurely shut down if required to install expensive controls, but does not express an intent that they be exempted from requirements entirely.

In summary, we draw the following conclusions from the legislative history. First, Congress intended the EPA to issue binding requirements for remaining useful life and to take into account characteristics of a source category in determining how remaining useful life should be addressed. Second, Congress intended remaining useful life to be used by states to tailor the application of a standard of performance to a particular source, not to exempt sources from a standard of performance altogether. Third, Congress intended the provision to primarily address the problem of existing sources with relatively short remaining useful lives, for which installation of retrofit technology might be unreasonably expensive.

C. Meaning of Terms in the Remaining Useful Life Provision

The term "shall" of course creates a mandatory requirement for this guideline; in other words, this guideline must "permit the State in applying a standard of performance to any particular source … to take into consideration, among other factors, the remaining useful life of the source."

However, contrary to some commenters' assertions, this mandatory requirement does not create unbounded authority for States to consider remaining useful life (or, for that matter, any

[50] The 1977 Amendments made the application of BSER in section 111(d)(1) to existing sources explicit by "by striking out 'emissions standards' in each place it appears and inserting in lieu thereof 'standards of performance'." Pub. L. 95-95 § 109(b)(1), 91 Stat. 685, 699.
[51] The EPA's interpretation of remaining useful life under the visibility program is discussed in detail below. Here we discuss only the legislative history.

other factor the state may wish to consider) in any way a State sees fit. Because this provision is part of the CAA, the EPA has the authority to interpret it in the first instance. In addition, ultimately, the EPA has the authority to review and determine whether state plans are satisfactory, including whether they achieve a requisite level of emission performance. Thus, the provision is best read to focus on the Administrator's obligation to promulgate guidelines that permit States to consider remaining useful life, and not on any "right" of the States Compare the provision with, for example, section 116 of the Act, which specifically reserves "the right of any State or political subdivision" to adopt more stringent requirements. 42 U.S.C. § 7416 (emphasis added). Thus, when Congress wanted to prohibit EPA from imposing constraints or parameters on State discretion, Congress knew how to say that.

The language of the remaining useful life provision is consistent with this. To "permit" is "to let (something) be done or occur," as in "the law permits the sale of such drugs." ACD at 902 to 903; see also OED ("To allow or give consent to (a person or thing) to do or undergo something."). In the dictionary's example usage, "the law permits the sale of such drugs," it is well understood that the law may (and likely does) set conditions on the sale. Thus, the natural interpretation of the remaining useful life provision is that the Administrator may set reasonable conditions on how, or reasonable terms under which, states are allowed or "permitted" to take into consideration remaining useful life.

In addition, the terms "consideration" and "among other factors" must be discussed. "Consideration" in this context is "regard or account: something taken, or to be taken, into account." ACD at 258; see also OED ("The taking into account of anything as a motive or reason; a fact or circumstance taken, or to be taken, into account; a reason considered."). Thus, "consideration" of "remaining useful life" means taking it into account "in applying a standard of performance to any particular source."

However, taking remaining useful life into account is not the same as making remaining useful life dispositive. This interpretation is bolstered by the language "among other factors." This indicates that "remaining useful life" is itself a "factor." A "factor" is "one of the elements that contribute to bring about any given result." ACD at 431 (emphasis added); see also OED ("a circumstance, fact, or influence which contributes to a result."). Thus remaining useful life is one element of the application of a State's standard of performance to a particular source, but it is not dispositive.

Finally, to "apply" is "to bring to bear; put into practical operation, as a principle, law, rule, etc." ACD at 61; see also OED ("To bring (a rule, a test, a principle, etc.) into contact with facts; to bring to bear practically; to put into practical operation"). Thus, "applying a standard of performance" to a "particular source" means putting the standard of performance into practical effect for that source. It does not mean exempting a particular source from a standard of performance, and as discussed in the legislative history, Congress knew how to allow sources to be exempted from requirements when Congress so desired.

This analysis of the language of the remaining useful life provision confirms much of the legislative intent discussed above. First, even after addition of the remaining useful life provision, in submitting approvable state plans, states would remain subject to minimum criteria in the emission guidelines promulgated by the Administrator; the remaining useful life provision

is not an unrestricted grant of a right to a state. Second, the Administrator can set conditions under which states are "permitted" to consider remaining useful life. Third, a state's consideration of remaining useful life should tailor the standard of performance to the source, not exempt it. Finally, the Administrator may review the state's application of the standard of performance to its sources, as part of the state plan, to assure that the state plan is "satisfactory," that is, meets the requirements of the CAA and the EPA's emission guidelines.

D. Remaining Useful Life in the Visibility Program

A closer look at the "remaining useful life" provision in the visibility program sheds additional light on the meaning of the provision under section 111(d)(1).

Under section 169A of the Act, SIPs are required to contain "a long-term [] strategy for making reasonable progress toward meeting the national goal," 42 U.S.C. 7491(b)(2)(B), of "prevention of any future, and the remedying of any existing, impairment of visibility" in certain National Parks and Wilderness Areas, *id.* (a)(1). A component of reasonable progress is the imposition of best available retrofit technology (BART) at certain existing sources. *Id.* (b)(2)(A).

Remaining useful life plays a part in the visibility program in two ways. In determining BART for a particular source, States (or EPA in the case of a FIP) "shall take into consideration" five enumerated factors, including "the remaining useful life of the source." *Id.* (g)(2). Similarly, the remaining useful life of existing sources (along with three other factors) must be taken into consideration in determining reasonable progress for the long-term strategy. *Id.* (g)(1).

Section 169A also requires EPA to issue "guidelines" for states to use in determining BART. *Id.* (b)(1). These guidelines must be followed for certain fossil-fuel fired power plants. *Id.* (b). In the "BART Guidelines," EPA has interpreted the "remaining useful life" BART factor and set very specific requirements (that is, requirements when it comes to the mandatory BART sources) for how States should consider it:

> The "remaining useful life" of a source, if it represents a <u>relatively short</u> time period, may affect the annualized costs of retrofit controls. … If the remaining useful life will clearly exceed th[e] time period [for amortization based on the type of control], the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculation.

40 CFR Part 51, App. Y, section IV.D.4.k (emphasis added).[52] Thus, the EPA interpreted the BART remaining useful life factor, consistent with Congressional intent, to address a possible unreasonable cost of retrofit controls at a particular source, and the EPA promulgated a specific methodology for taking the factor into consideration through computing the annualized cost of

[52] In guidance, EPA has recommended that the reasonable progress remaining useful life factor be evaluated in a similar way. "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, at 5-3 (June 1, 2007).

retrofit controls. The effect of this is, where a source may have a shorter remaining useful life than the amortization period for the retrofit control, the annual cost of the control will be correspondingly higher, and that may weigh (when considering the five factors) against determining that the particular control is BART. In promulgating this interpretation of the remaining useful life factor and corresponding requirement,the EPA rejected a comment that the remaining useful life factor should be interpreted to allow for postponement of BART requirements. 70 Fed. Reg. 39,104, 39,127/3 (July 6, 2005).

As explained in Section VIII of the preamble, these emission guidelines permit states to take into consideration remaining useful life in a manner consistent with the statute, legislative history, and prior agency interpretation in the BART Guidelines. The agency has determined the BSER in this case to be a set of measures that produce an emission performance level that is reasonable rather than maximal and that already accounts for an average level of performance at a regionalized level. In the emission guidelines, the EPA is giving the states the tools to take advantage of this flexibility, such as relatively long periods for sources to come into full compliance, multiple-year compliance periods, the ability to credit early action, the use of emissions trading, and the ability to link to other state plans to create larger emissions markets. Among other things, these mechanisms create economic incentives that reward over-performance of some sources, allow others to simply acquire credits or allowances to comply with their emission standard, and avoid the need for installation of costly pollution controls at sources on a short time horizon.

The availability of trading is particularly important to how remaining useful life is permitted to be considered in these emission guidelines. Essentially, trading amortizes the costs of compliance over compliance periods. Affected EGUs with relatively short remaining useful lives need only comply for a proportionately smaller number of periods as compared with affected EGUs with relatively long remaining useful lives. Thus, the cost of complying with these emission guidelines is distributed in a way that is consistent with how the BART Guidelines compute the cost of compliance for sources with relatively short remaining useful lives.

It is true that the same term may be interpreted in different ways in different contexts of the Clean Air Act. *Envt'l Def. et al. v. Duke Energy Corp. et al.*, 549 U.S. 561, 574 (2007). However, general consistency with the BART Guidelines is evidence that the EPA's interpretation of the remaining useful life provision here is reasonable. This is particularly true in light of the addition by Congress of both provisions in the 1977 Amendments and the Congressional concern in both provisions with the cost of retrofit controls. Our interpretation that remaining useful life does not create an exemption is also consistent with the EPA's rejection of the comment that remaining useful life should allow for postponement of BART requirements.

The 2005 promulgation of the BART Guidelines in part responded to a decision of the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), *Am. Corn Growers v. EPA*, 291 F.3d 1 (D.C. Cir. 2002) ("*Corn Growers*"). In *Corn Growers*, various parties challenged the EPA's initial promulgation of the Regional Haze Regulations, which created various requirements for SIPs to address visibility impairment. A particular requirement that was challenged was a "no degradation" provision that "require[d] implementation plans to 'provide for an improvement in visibility for the most impaired days over the period of the

implementation plan and ensure no degradation in visibility for the least impaired days over the same period.'" *Id.* at 11. The petitioners argued that this impermissibly conflicted with States' discretion to consider the four reasonable progress factors, including the remaining useful life factor. The court rejected this argument, first stating that the "no degradation" provision was consistent with the statutory purpose of progress toward the national goal. *Id.* at 12. Second, the court noted that degradation was not even one of the four factors and "[t]herefore, the states will be able to comply with the no degradation requirement while applying" the four factors. In essence, the EPA could permissibly constrain application of the four factors to be consistent with the statutory purpose.

This decision rebuts comments that the EPA must give states discretion to revise the goals in order to consider remaining useful life. First, in response to such comments, we note here (as elsewhere) that states can adequately consider remaining useful life, through the use of trading, even when they do not adopt a rate- or mass-based goal, but instead adopt the performance rates. No adjustment of a goal is necessary. However, if a state decides to reallocate burdens among its affected EGUs in order to address remaining useful life or other factors, it is permissible for the EPA to constrain the state's discretion so that application of those factors is consistent with the overall purpose of section 111(d): the set of affected EGUs as a whole achieves BSER-level emission reductions. To be sure, the agency agrees with commenters to the extent that the statute affords the EPA the discretion to decide in certain cases that a downward variation in emissions performance for some affected sources in a state under section 111(d) could be authorized. Indeed, the agency's implementing regulations have provided that ability for many years. But this does not mean that for a particular emissions guideline for a particular pollutant from a particular category of sources, the agency cannot reasonably decide that such downward variations are unwarranted and unnecessary. That is the case here.

Finally, we note two recent decisions regarding EPA's action on visibility SIPs. *Oklahoma et al. v. U.S. EPA*, 723 F.3d 1201 (10th Cir. 2013); *North Dakota et al. v. U.S. EPA et al.*, 730 F.3d 750 (8th Cir. 2013). Both the Eighth and Tenth Circuit Courts of Appeals rejected (among other arguments) generic arguments that States had primacy in determining BART and that EPA merely had the ministerial task of approving the State's determination. *Oklahoma*, 723 F.3d at 1207-10.; *North Dakota*, 730 F.3d at 760-61. In both cases, the courts upheld EPA's rejection of BART determinations that relied on cost estimates that either were inconsistent with the BART Guidelines, *Oklahoma* 723 F.3d at 1211-14, or otherwise flawed, *North Dakota*, 730 F.3d at 760-61. These decisions are consistent with our interpretation that we have the authority to prescribe the conditions under which remaining useful life can be considered and to reject as unsatisfactory plans that do not follow those conditions.

E. These Emission Guidelines and Remaining Useful Life

There are two general reasons that these emission guidelines satisfy the requirement that they "permit the State in applying a standard of performance to any particular source … to take into consideration, among other factors, the remaining useful life of the source." First, the emission guidelines are based on a reasonable interpretation of the provision, and second, on the record before us, the consequences of this interpretation are reasonable.

In general, the EPA may reasonably interpret ambiguous terms in the remaining useful life provision. The first (potentially) ambiguous term is "permit." In its natural reading, discussed above, the term "permit" is well understood in its legal usage to authorize the entity permitting an action to set binding conditions on the action that is permitted. If in fact the term is ambiguous, then the question that is left unanswered by the statute is whether the EPA may, as urged by commenters, decline to set binding conditions on the manner in which states can consider remaining useful life. Our interpretation that the EPA may do so, if not compelled, is certainly reasonable: to hold otherwise would be contrary to the typical supervisory role of the EPA in this cooperative federalism scheme (as discussed in *North Dakota* and *Oklahoma*) and, as it would allow states to relax requirements at affected EGUs virtually at will, contrary to the statutory purpose of achieving emissions performance levels equivalent to the BSER at affected EGUs.

The term "permit" does not specify the particular manner in which the EPA should permit States to consider remaining useful life (and other factors). It is therefore ambiguous with respect to this issue. We also note that the other terms discussed above, "applying," "consideration," and "factors" are not specific as to the manner of consideration. In sum, it is perhaps most straightforward to say that the entire phrase "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies" is ambiguous with respect to the issue of how the EPA may permit the State to do so. Thus, the EPA may reasonably specify the conditions under which States may take into consideration remaining useful life.

The specifications in these emission guidelines are reasonable. First, as discussed in detail above they are consistent with the language of the provision, with the legislative intent, and with our interpretation of the similar (but not identical) provision in the visibility program. As with the BART Guidelines, the EPA may reasonably be quite specific about the manner of consideration of this factor that is allowed. The additional flexibilities provided by these guidelines – adoption of the uniform performance rates, adoption of the rate-based goal but imposition of non-uniform rates, adoption of emission trading programs, adoption of the mass-based goal with flexibility to distribute allowances, or adoption of the state measures plan type – reasonably permit States to consider remaining useful life and other factors in various ways. For example, a state may adopt mass limits, and allocate a relatively greater number of allowances to a source with limited remaining useful life, on the understanding that the source will retire before 2030 and free up allowances for other sources. Similarly, under rate-based limits, a state could direct ERCs generated by a state-run or state-subsidized renewable energy or energy efficiency project to be transferred to an affected EGU with limited remaining useful life, or the state could simply impose a less stringent rate-based limit on the affected EGU.

Even if the state simply adopts the uniform performance rates, the state can take into account remaining useful life through trading, which as discussed in the previous section automatically takes into account remaining useful life. And under all plans, including the uniform performance rates, the requirements of these emission guidelines are phased in, beginning in 2022. The interim rates that states have to meet on average, by 2029, are: for fossil steam generators, 1534 lbs CO2/MWh, compared to the final rate, for 2030, of 1305 lbs CO2/MWh; and for natural gas combustion turbines, 832 lbs/MWh, compared to the final rate,

for 2030, of 771 lbs CO2/MWh. If a state phased in reductions evenly, starting in 2022, then the steam rate would be 1764 and the gas rate would be 910. See preamble, section V.B.7., p. 665, fn. 621.[53] Furthermore, states have the ability to set their own glide path so long as it achieves the interim and final goals. Thus, affected EGUs with a short remaining useful life ending at or before 2030 will face considerably smaller compliance costs on an average annual basis than affected EGUs with longer remaining useful lives extending well past 2030, as the latter must comply with the final rates. The same effect, in a somewhat more attenuated form, is true for affected EGUs with remaining useful lives ending soon after 2030. Given these reasonable mechanisms for considering remaining useful life, it is permissible (as seen in *Corn Growers*) for these emission guidelines to ensure that affected EGUs as a group in a state achieve BSER-determined levels of emission reductions.

Several commenters said that that the statute does not authorize the EPA to require other facilities to achieve greater reductions to compensate for a facility that the state determines warrants relief based on remaining useful life. One said that consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve an emission performance rate determined by the BSER, and that the EPA turns that approach on its head by prohibiting a state from providing such relief to a specific facility unless it can identify another facility to "punish" by requiring additional emissions reductions to offset that relief.

The EPA disagrees with these comments, for several reasons. First, as noted above, the availability of trading substantially accounts for remaining useful life. Second, the EPA is not establishing the BSER emission level for individual facilities, and then requiring better-than-BSER from some facilities to make up for worse-than-BSER performance that a state authorizes for other facilities because of a short remaining useful life. Rather, as previously noted, the guidelines set EGU performance rates and state goals that represent the average or aggregate emission level achievable by affected EGUs based on regional average estimates of the impact of applying the BSER to collective groupings of affected EGUs.[54] In estimating the amount of improvement achievable through each building block (e.g., improvement in heat rate or amount of generation shift to lower-emitting EGUs), the EPA relies on estimating the average level achievable by EGUs in a region rather than attempting to estimate a level achievable by each and every affected EGU in the absence of trading. Thus, the fact that an individual facility may be unable, for example, to achieve the average level of heat rate improvement assumed in goal-setting is consistent with the EPA's analysis, and does not undermine the EPA's determination of state goals.

Third, for states that adopt a mass goal, the retirement of an EGU at the end of its

[53] Similar considerations apply to the mass goals.

[54] The EPA expects that states that choose to adopt the national EGU performance rates for all of their EGUs would permit ERC trading, rather than requiring each facility to meet the applicable rate without trading. In effect, the presence of trading means that the EGU performance rates will be achieved on average by the EGUs involved in trading, rather than be achieved by each facility in the absence of trading.

remaining useful life actually eases compliance by other EGUs post-retirement.[55] For states that adopt a rate goal, a similar effect would happen when higher-emitting EGUs retire. Depending on the timing of the retirement, the retirement may help the state's affected EGUs to achieve the required level in the state plan (i.e., the national EGU performance rate, or the rate-based or mass-based state goal), even if the state were to place lesser requirements on an EGU during its limited remaining useful life. In such cases, the retirement would not create any deficit of emission reductions to be made up by other EGUs.

The EPA has considered a scenario in which an EGU might not be scheduled to retire until just before the end of the interim period, or until soon after the final goal must be met,[56] and the state would prefer to require no emission reduction from the retiring EGU in the meantime. Under this hypothetical scenario, the lack of emission reduction requirements for the EGU that is planning retirement on these timelines could create an emission reduction deficit. However, for this limited scenario and in light of the other flexibilities provided in these guidelines, the EPA believes that it continues to be reasonable to require the state plan as a whole to meet the state goal. The EPA would therefore be justified in disapproving a plan that did not achieve compensating emissions reductions to meet the state goal in this instance.

Finally, contrary to the views of commenters, the EPA believes that the agency has discretion under section 111(d) over whether or not the remaining useful life criterion should be grounds for diminishing the overall emission reduction required by the guidelines for a particular source category. Stated another way, commenters believe the statute unambiguously requires the agency to approve state plans that achieve less emission reductions than the agency knows are achievable. The agency has long recognized that there may be grounds for this for some pollutants from some categories of sources, under section 111(d) and the agency's implementing regulations. However, for a particular emissions guideline for a particular pollutant from a

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[55] As discussed in the sections on the legislative history and the visibility program, EPA believes that Congress in adding the remaining useful life provision was primarily concerned with sources with relatively short remaining useful lives. However, in these emission guidelines EPA is not assuming any particular length of life for affected EGUs, and history has shown that some fossil fuel-fired EGUs have continued to operate beyond what was assumed to be their lifetime. The benefit to other EGUs mentioned above eventually applies regardless of how long an affected EGU operates before retirement, albeit with reduced benefits for other EGUs as the retirement happens farther in the future.

[56] Under this scenario, the affected EGU would continue to operate and generate revenue for roughly 15 years from promulgation of these guidelines. This is significant for two reasons. First, it seems appropriate that an EGU that is operating until roughly 2030 should bear substantial responsibility for obtaining emission reductions despite its plans to retire eventually. Under the agency's interpretation of "remaining useful life," a plant that plans to operate for 15 years or more would justify lesser relief from standards of performance on the basis of remaining useful life. Second, the typical debt life for coal-fired EGU is 20 years, so the number of affected EGU that have not repaid their debt dwindles significantly by 2030. The number of facilities that are not fully depreciated based on book life also diminishes over time.

particular category of sources, the agency can reasonably decide that such adjustments are unwarranted and unnecessary. As discussed above, that is the case here.

To summarize, the agency has determined the BSER in this case to be a set of measures that produce an emission performance level that is reasonable rather than maximal and that represents an average level of performance achievable by EGUs in each of the three interconnect regions. In the emission guidelines, the EPA is giving states flexibility on the design of the state programs to achieve the EGU performance rates or state goals. The guidelines also give the states tools to take advantage of this flexibility, such as relatively long periods for sources to come into compliance, the ability to credit early action, the ability to use emissions trading, multi-year compliance periods, and the ability to link to other state plans to create larger emissions markets. These tools can be used to create economic incentives that reward over-performance of some sources, and allow others to simply acquire credits or allowances to comply with their emission standard. While there are technologies that could require expensive retrofits available for EGUs to reduce their emissions, including co-firing with natural gas,[57] re-powering with natural gas, or CCS, we do not expect that any affected EGUs will need to rely on them and, in fact, we did not include them in the BSER. Thus, there is no need for affected EGUs with limited remaining useful life to install costly pollution controls. Because of these features of the guidelines, the EPA believes that any unit-specific considerations that a state may find warrant the application of a less stringent standard of performance are fully capable of being addressed without reducing the overall emission performance level. Given this determination, these guidelines require that state plans achieve an aggregate emission level from the affected EGUs, and may be disapproved if they do not.

The EPA's interpretation of the remaining useful life provision is also reasonable on the record before us. As discussed in detail in Section V of the preamble and supporting documents, there is substantial evidence that BSER, as expressed in the performance rates, rate-based goals, and mass-based goals, is achievable considering costs. In other words, affected EGUs with relatively short remaining useful lives will have cost-effective ways to comply and will not be required to make expensive initial capital expenditures that would be hard to justify in light of that short remaining useful life. Indeed, such EGUs need not install retrofit controls at all, but may purchase ERCs or allowances in order to comply, or may negotiate directly with qualified generators of credits.

With respect to stranded assets, the legislative history indicates that Congress was primarily concerned with the marginal costs of compliance with the emission guidelines going forward and not with past, sunk costs. Notwithstanding our interpretation of the remaining useful life provision, the agency recognizes it to be possible that there could be circumstances under which an emission guideline should explicitly address a severe possibility of stranded assets. However, our analysis shows that stranded assets are not likely to be an issue under these emission guidelines (unless of course a State at its discretion decides to shut down certain affected EGUs).[58] Thus, although nothing in the remaining useful life provision explicitly compels us to take into account the possibility of stranded assets, and nothing in the legislative

[57] In many instances, co-firing could be accomplished without significant retrofits; in other cases, it might require retrofits.
[58] See Memorandum to Docket, "Analysis of Potential for Stranded Assets."

history indicates the provision should be interpreted to do so, this emission guideline nonetheless reasonably addresses the potential problem.

F. Variances Under the Clean Water Act

Two U.S. Supreme Court opinions have discussed variances under the Clean Water Act ("CWA"). *E. I. Du Pont de Nemours & Co. v. Train*, 430 U.S. 112 **(**1977**);** *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64 (1980). In *Du Pont*, the Court examined section 301(b) of the CWA, which required EPA to promulgate "effluent limitations that shall be achieved by existing point sources in two stages. By July 1, 1977, the effluent limitations shall require the application of the best practicable control technology currently available [BPT]; by July 1, 1983, the limitations shall require application of the best available technology economically achievable [BAT]." *Id.* at 118 n.5, 121. However, section 301(c) authorized EPA to grant variances to individual point sources from this technology standard if (among other things) the modified requirements "represent the maximum use of technology <u>within the economic capability of the owner or operator</u>." *Id.* at 118 n.5 (emphasis added). Industry challenged the EPA's authority to promulgate effluent limitations that would be directly incorporated into section 402 permits, "except for the limited variances allowed by the regulations themselves and by § 301(c)." *Id.* at 124. Based on the language of section 301, including section 301(c), the Court held, "the statute authorizes the 1977 limitations as well as the 1983 limitations to be set by regulation, so long as some allowance is made for variations in individual plants, as EPA has done by including a variance clause in its 1977 limitations."

On the other hand, section 306 of the CWA required EPA to promulgate "standards of performance," defined as a "standard for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the best available demonstrated control technology,… including, where practicable, a standard permitting no discharge of pollutants." *Id.* at 137. In the decision below, the circuit court had held that variance provisions were a necessary part of the regulatory process and remanded the rule to EPA to "come forward with some limited escape mechanism for new sources." *Id.* at 138. The Court reversed that portion of the circuit court's judgment, noting (among other things) that "[i]n striking contrast to § 301(c), there is no statutory provision for variances." *Id.*

In *Crushed Stone*, the Court reviewed the EPA regulatory provision governing variances from the BPT limitations. The Court described the provision as follows:

> Although a greater than normal cost of implementation will be considered in acting on a request for a variance, economic ability to meet the costs will not be considered. A variance, therefore, will not be granted on the basis of the applicant's economic inability to meet the costs of implementing the uniform standard.

449 U.S. at 68. The Court stated, "The issue in this case is whether the BPT variance provision must allow consideration of the economic capability of an individual discharger to afford the costs of the BPT limitation," an issue the Court had declined to address in *Du Pont*. *Id.* at 72. Based on the similarity of the language of section 301(c) to the BAT standard, the Court reasoned that section 301(c) applied only to variances from the BAT effluent limitations and

contained similar language to the BAT standard, and "[a] § 301(c) variance [] creates for a particular point source a BAT standard that represents for it the same sort of economic and technological commitment as the general BAT standard creates for the class." *Id.* at 74. On the other hand, a similar variance for the BPT limitation based on the economic capability of the applicant would be contrary to the purpose and structure of the CWA. *Id.* "Necessarily, if pollution is to be diminished, limitations based on BPT must forbid the level of effluent produced by the most pollution-prone segment of the industry …. So understood, the statute contemplated regulations that would require a substantial number of point sources with the poorest performances either to conform to BPT standards or to cease production." *Id.*

Du Pont shows that a court cannot require EPA to provide a variance provision as a "necessary part of the regulatory process" when the statute does not explicitly provide for one. For these emission guidelines, the remaining useful life provision in section 111(d)(1) does not explicitly provide for a variance. Furthermore, *Crushed Stone* shows that it is permissible, based on the structure and purpose of an environmental statute, to not allow a variance from a standard for existing facilities on the basis of economic inability. In other words, EPA is not compelled to (unless the statute so provides) to allow for variances if a facility might "cease production" and strand its assets. While the EPA has designed these guidelines to avoid stranded assets, and our analysis confirms that design, see subsection IX.E above, the statute does not explicitly require the EPA to do so. In general, the application of the BSER under section 111(d) will require some costs of compliance for existing sources, and for existing sources operating on thin profit margins, these costs could be a contributing factor to those sources ceasing production (although again the design of these emission guidelines are intended to avoid this effect, as confirmed by our analysis). Thus, it would be contrary to the purpose of section 111(d), that is, to reduce emissions of designated pollutants from existing sources through the application of the BSER, for the EPA to create the possibility of variances based on stranded assets.

We note finally that the remaining useful life provision was added in the 1977 Amendments. Thus, Congress was aware of the variance provision in section 301(c) of the CWA (also known as the 1972 Federal Water Pollution Control Act Amendments) and knew how to create an explicit variance based on economic capability. However, Congress did not do so in the remaining useful life provision and so it can be inferred that Congress did not intend to mandate that the remaining useful life provision be interpreted to provide such a variance.

X. Response to Claims that the CPP Raises Constitutional Concerns

A. Tenth Amendment

Commenters have claimed that the emission guidelines and requirements for 111(d) state plans violate principles of federalism embodied in the U.S. Constitution. These commenters claim that states will be unconstitutionally "coerced" or "commandeered" into taking certain actions in order to avoid the prospect of either a federal 111(d) plan applying to sources in the state or losing federal funds.

We disagree with these commenters' conclusions, which rest on fundamental misunderstandings or inaccurate descriptions of the Clean Air Act, this rule, and the applicable case law. As an initial matter, we agree that it is black-letter constitutional law that the federal

government cannot coerce or commandeer state governments into enacting a federal regulatory program.[59] But the emission guidelines and requirements for 111(d) state plans provided in this rule do no such thing. Far from violating principles of federalism, this rule and CAA section 111(d) fully respects such principles. In particular, they provide states with the initial opportunity to submit a satisfactory state plan, with no consequences to states in their sovereign capacity should they decline to participate. Rather, if a state declines to take advantage of that opportunity, affected EGUs in that state will instead be subject to a federal plan that satisfies statutory requirements.[60] No state is legally required to submit a 111(d) plan, and the lone consequence for failing to submit a satisfactory 111(d) plan—imposition of a federal plan for affected EGUs in the state—does not violate the Tenth Amendment.

1. Federal Plan

The prospect of a federal plan applying to affected EGUs in a state does not "coerce" or "commandeer" that state into submitting its own satisfactory 111(d) plan. In CAA section 111(d)(2), Congress required the EPA to prescribe and implement a federal plan where states do not submit or enforce a satisfactory state plan. Affected EGUs in that state would thus be subject to a federal plan that satisfies statutory requirements.[61]

This approach is consistent with cooperative federalism regimes that federal courts have routinely upheld against Tenth Amendment challenges.[62] Among other things, this is because a

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[59] *See, e.g.*, *New York v. United States*, 505 U.S. 144, 161 (1992) (citing *Hodel v. Va. Surface Mining & Reclamation Assn., Inc.*, 452 U.S. 264, 288 (1981)) ("Congress may not simply 'commandeer the legislative processes of the States by directly compelling them to enact and enforce a federal regulatory program.'"); *Printz v. United States*, 521 U.S. 898 (1997) (holding the same with respect to state officers).

[60] Among other things, a federal plan will implement standards of performance subject to specific statutory requirements. *See* 42 U.S.C. § 7411(a)(1). The APA and CAA would prohibit the imposition of any federal plan that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(a). Particularly given these independent constraints on the EPA's authority with respect to any potential federal plan, the prospect of any such plan would not commandeer states or coerce them into submitting their own state plans.

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[62] *See, e.g.*, *Hodel v. Va. Surface Mining & Reclamation Ass'n, Inc.*, 452 U.S. 264, 283–93 (1981); *Texas v. EPA*, 726 F.3d 180, 196–97 (D.C. Cir. 2013) (noting that "Supreme Court precedent repeatedly affirm[s] the constitutionality of federal statutes that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it").

federal plan would regulate private entities, not "the States as States," and there is "no Tenth Amendment impediment" when, as here, a federal plan would regulate "private persons and businesses ...."[63] As the U.S. Supreme Court explained in upholding the federal-plan aspect of another cooperative federalism regime, the Surface Mining Control and Reclamation Act (SMCRA):

> [T]the steep-slope provisions of the Surface Mining Act govern only the activities of coal mine operators who are private individuals and businesses. Moreover, the States are not compelled to enforce the steep-slope standards, to expend any state funds, or to participate in the federal regulatory program in any manner whatsoever. If a State does not wish to submit a proposed permanent program that complies with the Act and implementing regulations, the full regulatory burden will be borne by the Federal Government. Thus, there can be no suggestion that the Act commandeers the legislative processes of the States by directly compelling them to enact and enforce a federal regulatory program. The most that can be said is that the Surface Mining Act establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.[64]

The Court noted that SMCRA thus "resembles a number of other federal statutes that have survived Tenth Amendment challenges in the lower federal courts," citing a case in which the Second Circuit upheld the constitutionality of the Clean Air Act against a similar challenge.[65] One constitutional scholar has noted that the "straightforward" unanimous opinion in *Hodel* was "nothing more than a preemption case" because the provision at issue "governed only the activities of coal mine operators who are private individuals and businesses"—not the states in their sovereign capacity—and "the states were still free to promulgate whatever regulations they wished so long as they were not inconsistent with minimum federal guidelines."[66]

A decade later, in *New York v. United States*, the Court reaffirmed the principle that merely offering states an opportunity to regulate, with the understanding that the federal government will otherwise step in, does not "compel" the states to regulate—once again citing as examples pollution-control statutes administered by EPA:

> [W]here Congress has the authority to regulate private activity under the Commerce Clause, we have recognized Congress' power to offer States the choice of regulating that activity according to federal standards or having state law pre-empted by federal regulation. This arrangement, which has been termed "a program

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[63] *Hodel*, 452 U.S. at 287 (citing *Nat'l League of Cities v. Usery*, 426 U.S. 833, 845 (1975)); *cf. Printz v. United States*, 521 U.S. 898, 920 (1997) (quoting *New York v. United States*, 505 U.S. 144, 166 ("The Framers explicitly chose a Constitution that confers upon Congress the power to regulate individuals, not States.").

[64] *Hodel*, 452 U.S. at 288–89 (internal citations omitted).

[65] *See Hodel*, 452 U.S. at 289 & 30 (citing, *inter alia*, *Friends of the Earth, Inc*. v. *Carey*, 552 F.2d 25, 36–39 (2d. Cir. 1977)).

[66] Laurence H. Tribe, American Constitutional Law 389–90 (2d ed. 1988).

> of cooperative federalism," is replicated in numerous federal statutory schemes. These include the Clean Water Act … [and]… the Resource Conservation and Recovery Act of 1976....
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> [Under these cooperative federalism regimes], as by any other permissible method of encouraging a State to conform to federal policy choices, the residents of the State retain the ultimate decision as to whether or not the State will comply. […] If state residents would prefer their government to devote its attention and resources to problems other than those deemed important by Congress, they may choose to have the Federal Government rather than the State bear the expense of a federally mandated regulatory program, and they may continue to supplement that program to the extent state law is not pre-empted. [67]

The Clean Air Act and this rule recognize the importance of preserving the division of power between state and federal governments.[68] Congress, in enacting CAA section 111(d)(2), required the EPA to develop a reasonable federal plan to regulate affected sources where the state does not. Federal statutes and regulations governing commercial facilities that emit pollutants with substantial effects on interstate commerce are well within the bounds of the federal government's Commerce Clause authority.[69] The fact that section 111(d) stays the EPA's reasonable exercise of that constitutional power while states consider whether or not to develop their own satisfactory plan to regulate those private entities does not offend the Tenth Amendment. [70]

2. Sanctions

States that decline to take certain actions under this rule will not face the prospect of sanctions, such as withdrawn federal highway funds. Here again, we acknowledge the general legal principle that conditions on a state's continued receipt of federal funds can cross the constitutional line between permissible "encouragement" and impermissible "coercion."[71] But that principle simply has no applicability here because there are no federal funds at issue. CAA section 111 does not contain sanctions provisions, and we are finalizing revisions to the emission

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[67] *New York v. United States*, 505 U.S. 144, 167–168 (quoting *Hodel*, 456 U.S. at 289) (internal citations omitted).
[68] *See Printz v. United States*, 521 U.S. 898, 921–22 (1997) (citing The Federalist No. 51, at 323).
[69] *See, e.g.*, *Hodel*, 452 U.S. at 282 ("[W]e agree with the lower federal courts that have uniformly found the power conferred by the Commerce Clause broad enough to permit congressional regulation of activities causing air or water pollution, or other environmental hazards that may have effects in more than one State.").
[70] *Cf. NFIB v. Sebelius*, 132 S. Ct. 2566, 2603 (2012) (plurality) ("The states are separate and independent sovereigns. Sometimes they have to act like it.").
[71] *See NFIB v. Sebelius*, 132 S. Ct. 2566, 2603–04 (citing *New York v. United States*, 505 U.S. 144, 175 (1992); *South Dakota v. Dole*, 483 U.S. 203, 208, 211) (1987).

guidelines making explicit that the EPA will not withhold federal funds from a state on account of that state's failure to submit or implement an approvable 111(d) state plan.[72]

Some commenters pointed to section 110(m) as a possible source of the EPA's sanction authority.[73] Section 110(m) grants the EPA discretionary authority to withhold some federal highway funds under certain conditions. However, section 110(m) requires the EPA to adopt regulations to "establish criteria for exercising" this discretionary authority, and the only EPA regulations implementing section 110(m) apply to SIPs submitted under section 110.[74]

The EPA never intended to even imply that we would contemplate using this authority to encourage state participation in this rule under section 111. To the contrary, we believe that imposition of a federal plan rather than sanctions is the appropriate path in the context of this program. Accordingly, regardless of whether the EPA could theoretically apply discretionary sanctions against states in the section 111(d) context, the rule today forbids the agency from exercising any such authority. We have included in this rule a provision that prohibits the agency from imposing sanctions in the event that a state fails to submit or implement a satisfactory plan under this rule. As states consider whether to take advantage of the opportunity to develop state plans, they can be assured that the EPA will not withdraw federal funding should they decline to participate. There are no "sanctions" against the States available under this rule.

3. Direct Regulation of States

This rule does not promulgate a federal plan. Even if some sources regulated by a future federal plan are owned or operated by states, such a federal plan would still not violate the Tenth Amendment because it "would not require the States *in their sovereign capacity* to regulate their own citizens."[75] In *Reno v. Condon*, the Supreme Court upheld a generally applicable federal law that regulated states and private individuals that sold or disclosed certain personal information. Although state governments were among the entities that sold or disclosed this information, and were thus regulated by the federal law, the Court explained that this raised no Tenth Amendment impediment because the law regulated the states "as owners of databases," not in their sovereign capacities.[76] The federal law did not require state legislatures to enact laws or regulations, and did not require state officials to assist in the enforcement of the federal law against private

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[72] Some commenters alternatively claimed that emission offset requirements could constitute sanctions that coerce states in violation Tenth Amendment. Even if those sanctions were somehow available pursuant to this rule—which they are not, for the reasons discussed below—those offsets would not implicate the Tenth Amendment because they are directed at the "States as States." *See Hodel*, 452 U.S. at 287 (citing *Nat'l League of Cities v. Usery*, 426 U.S. 833, 845 (1975)).

[73] Other commenters point to CAA section 179 as a possible direct source of this sanctions authority. However, the mandatory sanctions outlined in section 179 clearly apply only in the contexts of nonattainment SIPs and responses to SIP Calls made under CAA section 110(k)(5). *See* 42 U.S.C. § 7509(a).

[74] 40 CFR 52.30 (defining "plan or plan item").

[75] *Reno v. Condon*, 528 U.S. 141, 151 (2000).

[76] *Id.*

individuals.[77] Any federal plan regulating state-owned or state-operated EGUs would similarly not be regulating states in their sovereign capacities.

B. Contract Clause

Commenters raised concerns that the portfolio approach could violate the Contract Clause because "a state-driven portfolio approach that adopts EPA's suggestion to use the renewable energy and RECs [renewable energy credits] located in the state to satisfy a state goal will take that RE [renewable energy] and RECs out of the hands of the purchaser ... and into the hands of the state to meet its objectives." Insofar as commenters are uniquely concerned about the Contract Clause implications of the portfolio approach, those concerns are moot because the EPA is not finalizing the portfolio approach. Other commenters, however, asserted that any regulations interfering with contractual rights would violate the Contract Clause.

The Contract Clause provides that, "No State shall ... pass any ... Law impairing the Obligation of Contracts ...."[78] By its terms, the Contract Clause does not apply to the federal government. Accordingly, commenters' concerns about the Contract Clause implications of the provisions of hypothetical state plans are best reserved until state plans have actually been submitted. Furthermore, we note that commenters have tended to ignore the full Contract Clause analysis in their comments.

The Supreme Court has explained that there are two primary questions in a Contract Clause analysis. The first is whether there is a change in a state law[79] that operates as a "substantial impairment" of a contractual relationship.[80] "This inquiry has three components: [1] whether there is a contractual relationship, [2] whether a change in law impairs that contractual relationship, and [3] whether the impairment is substantial."[81] Commenters have largely stopped their analysis at whether a hypothetical state law would "impair" a contract, ignoring the fact that a "*substantial* impairment" typically (although not necessarily) involves a total "destruction of contractual expectations."[82] Highly regulated industries like utilities have a difficult time showing that a contract impairment is "substantial"—contractual agreements in the industry are typically formed with the expectation of additional, future government regulation.

Second, even assuming *arguendo* that a hypothetical state plan provision did substantially impair a contract, there is still no constitutional violation if the law has a "legitimate public purpose," like remedying a "broad and general social or economic problem."[83] This requirement

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[77] *Id.* (citing *New York v. United States*, 505 U.S. 144 (1992); *Printz v. United States*, 521 U.S. 898 (1997)).
[78] U.S. Const. art. I, § 10, cl. 1.
[79] Again, we note that there have not yet been changes in state law in response to this rule.
[80] *General Motors Corp. v. Romein*, 503 U.S. 181, 186 (citing *Allied Structural Steel Co. v. Spannaus*, 438 U.S. 234, 244 (1978); *Energy Reserves Group, Inc. v. Kansas Power & Light Co.*, 459 U.S. 400, 411 (1983)).
[81] *Id.*
[82] *Energy Reserves Group, Inc.*, 459 U.S. at 411–12.
[83] *Energy Reserves Group, Inc.*, 459 U.S. at 412

is to ensure that the state law is regulating in the public interest, rather than merely trying to benefit a special interest by excusing it from contract obligations. It is likely that any generally applicable state plan would satisfy this requirement.

C. Compact Clause

Some commenters and individuals have asserted that multi-state plans would require congressional consent pursuant to the Compact Clause[84] or section 102(c) of the Clean Air Act.[85] Some commenters' concerns flow from the faulty assumption that enforceable multi-state agreements will allow states to directly enforce the terms of a binding multi-state agreement against each other, as is often the case with interstate agreements covered by the Compact Clause.

These commenters and individuals are incorrect, first and foremost because they misunderstand the nature of multi-state plans under this rule. As a conceptual and legal matter, the "multi-state plans" envisioned under this rule are sets of independently adopted and enforced state laws that mirror (or allow for interaction with) other state laws. In this sense, the state laws comprising multi-state plans are nothing more than reciprocal legislation of the sort that states have routinely enacted in consultation with each other, including in the context of the Clean Air Act. States are allowed to cooperate in this way without obtaining congressional approval under either the Compact Clause or section 102 of the Clean Air Act.

1. The Compact Clause does not apply

The Compact Clause provides that, "No State shall, without the Consent of Congress ... enter into any Agreement or Compact with another State ...."[86]

Despite the provision's superficial breadth, "not all agreements between States are subject to the strictures of the Compact Clause."[87] Rather, the Compact Clause requires congressional consent only for a narrow subset of interstate agreements that tend to increase "the political power in the States" in a way that encroaches upon or interferes with federal government.[88] Thus, for example, Compact Clause concerns may arise when agreements authorize states to exercise powers they could not otherwise, or that actually delegate state

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[84] U.S. Const. art. I, § 10, cl. 3.
[85] 42 U.S.C. § 7402(c).
[86] U.S. Const. art. I, § 10, cl. 3.
[87] *See U.S. Steel Corp. v. Multistate Tax Comm'n*, 434 U.S. 452, 469 & n.21 (1978); *Ne. Bancorp, Inc. v. Bd. of Governors of Fed. Reserve Sys.*, 472 U.S. 159, 175 (1985) (citing *Virginia v. Tennessee*, 148 U.S. 503, 518–19 (1893)).
[88] *See, e.g., U.S. Steel Corp.*, 434 U.S. at 468, 471 (1978) (describing this rule as, "stat[ing] the proper balance between federal and state power with respect to compacts and agreements among States"); *New Hampshire*, 426 U.S. at 369 (quoting *Virginia v. Tennessee*, 148 U.S. 503, 519 (1893) ("application of the Compact Clause is limited to agreements that are 'directed to the formation of any combination tending to the increase of political power in the states, which may encroach upon or interfere with the just supremacy of the United States.'").

sovereign power to an interstate entity or process.[89] By contrast, no congressional consent is necessary when, as here, states merely cooperate to achieve a common goal by independently adopting and enforcing state laws that mirror (or allow for interaction with) other state laws. Perhaps given the modest scope of the Compact Clause's prohibition, no interstate agreement has ever been invalidated for lacking congressional consent.[90]

As noted in section VIII.C.5 of the preamble, the multi-state plans envisioned under this rule are, as a legal matter, coordinated sets of single-state plans that do not enhance or diminish the sovereign authority of any state, and that do not enhance state power vis-à-vis the federal government.[91] Rather, the state laws comprising a multi-state plan are "nothing more than reciprocal legislation"[92] of the sort that states have routinely enacted in consultation with each other, including within the context of the Clean Air Act. They do not implicate the Compact Clause.

For example, states coordinating to meet a joint CO_2 emission goal under this rule is similar to the relationship between states coordinating SIP submissions to attain the NAAQS in an interstate nonattainment area.[93] In both cases, the states coordinate their actions in a way that, cumulatively, the measures applicable in each state will lead to achievement of a common interstate goal (with the EPA evaluating the sufficiency and success of the plans on a holistic, interstate basis). Despite the shared goal, in both cases, the mere fact of coordination has no

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[89] *See, e.g.*, *U.S. Steel Corp.*, 434 U.S. at 472–73.

[90] David E. Enghdahl, *Characterization of Interstate Arrangements: When is a Compact Not a Compact?*, 64 MICH. L. REV. 63, 69 (1965) ("[I]ndeed, in every case since *Virginia v. Tennessee* in which an interstate arrangement has been challenged for lack of congressional consent, it has been held exempt from the consent requirement."); William Funk, *Constitutional Implications of Regional CO2 Cap-and-Trade Programs: The Northeast Regional Greenhouse Gas Initiative as a Case in Point*, 27 UCLA L. J. ENVTL. L. & POL'Y 353, 361 (2009) ("[O]f the hundreds of interstate agreements and compacts that have been adopted in our nation's history not one has ever been found to have been required to have congressional consent despite numerous challenges to agreements and compacts brought in both state and federal court.").

[91] *See U.S. Steel Corp.*, 434 U.S. at 469 & n.21 (quoting Laurence H. Tribe, *Intergovernmental Immunities in Litigation, Taxation, and Regulation: Separation of Powers Issues in Controversies about Federalism*, 89 Harv. L. Rev. 682, 712 (1976)) (reciprocal state tax statutes do not implicate the Compact Clause because "they neither project a new presence onto the federal system nor alter any state's basic sphere of authority").

[92] *See U.S. Steel Corp.*, 434 U.S. at 476–77.

[93] Indeed, in the 1990 Clean Air Act Amendments, Congress added section 174(c) to clarify that, for multi-state nonattainment areas, states can jointly undertake the Act's nonattainment planning procedures—even without an interstate compact. *See* 42 U.S.C. § 7504(c) ("In the case of a nonattainment area that is included in more than one State, the affected States may jointly, through interstate compact *or otherwise*, undertake and implement all or part of the planning procedures" under section 174) (emphasis added); H.R. Rep. 101-490, pt. 1, at 226 (1990) (section 174(c) "clarifies" that in such instances "states may jointly undertake planning procedures). Section 174(c) does not itself provide congressional consent for interstate compacts to implement section 174's planning requirements.

effect on each state's sovereign legal authority.[94] For example, the legally applicable rules in a given state are adopted by that state individually, not by a joint entity or other interstate mechanism. Similarly, the mere fact that the states coordinate their rules does not grant them the authority to directly enforce each other's rules, or to take direct legal action against a state that is failing to implement its own rules.

Another example is provided by SIP provisions adopted to comply with the CAA's Good Neighbor Provision[95] that allow sources in one state to engage in emissions trading with out-of-state sources.[96] Although the trading provisions allow for interstate exchanges between sources, the states have direct legal authority only over the sources within their own borders. Furthermore, while participation in an emissions trading program may be premised on the state's adoption of a model or uniform law, the state develops and submits the SIP on its own initiative—pursuant to its independent, sovereign authority. Interstate emissions trading programs that states may which to develop under this rule similarly would not implicate the Commerce Clause.

Finally, as noted above with respect to the Tenth Amendment, states cannot be legally required to implement a federal regulatory program. Should states with satisfactory state plans decide to stop implementing the plan as a matter of state law, the Tenth Amendment provides that they may do so, and section 111(d)(2) provides for federal regulation of sources in that state. This is unlike many interstate compacts, which—with congressional consent—can encroach upon ordinary principles of state sovereignty by legally requiring a member state to continue implementing the terms of the agreement.[97] As with multi-state SIPs under section 110, nothing legally requires a state that has submitted its plan as part of a "multi-state" plan to continue implementing it.[98] This is true whether the state submitted its plan as part of a coordinated "multi-state" effort, or as a stand-alone plan. There is thus no merit to commenters' contention that all multi-state plans would necessarily require congressional consent under the Compact Clause.

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[94] *Cf. New York v. United States*, 505 U.S. 144, 183 (1992) ("The fact that the Act, like much federal legislation, embodies a compromise among the States does not elevate the Act (or the antecedent discussions among representatives of the States) to the status of an interstate agreement requiring Congress' approval under the Compact Clause.").
[95] 42 U.S.C. § 7410(a)(2)(D)(i)(I).
[96] *See, e.g.*, 66 FR 43795 (Aug. 21, 2001) (final action approving Pennsylvania SIP revision to allow certain Pennsylvania sources to participate in the interstate NO_x Budget Trading Program).
[97] *See, e.g., West Virginia ex rel. Dyer v. Sims*, 341 U.S. 22 (1951) (applying contract law estoppel principles under an interstate compact).
[98] For similar reasons, the requirement that states submit plan revisions to EPA for approval does not mean that a state is legally required to continue implementing the original state plan. As with SIPs under section 110, the EPA cannot actually prevent a state from changing its state law, or refusing to continue implementing the state plan as currently approved by the EPA. Until EPA approves the revision, the only entities that continue to be legally subject to, or "bound by," the terms of the original state plan are (1) entities regulated by the original plan, and (2) in some cases, the EPA itself.

2. Section 102(c)'s prohibition does not apply

Commenters are also off-base in their claim that CAA section 102(c) prohibits states from forming multi-state plans. The text and statutory context of CAA section 102(c) indicates that Congress did not intend to preempt a broader range of state action than would otherwise require congressional consent under the Compact Clause.

Section 102(c) is situated in a larger section entitled, "Cooperative activities." The thrust of that section—as with the Act as a whole[99]—is that where appropriate, Congress wanted to encourage interstate efforts at addressing pollution control. For example, section 102(a) of the Act expressly directs the EPA to encourage all manners of cooperative activities between states:

> The Administrator shall encourage cooperative activities by the States and local governments for the prevention and control of air pollution; encourage the enactment of improved and, so far as practicable in the light of varying needs, uniform State and local laws relating to the prevention and control of air pollution; and encourage the making of agreements and compacts between States for the prevention and control of air pollution.[100]

It is within this context of encouraging interstate cooperation that Congress included section 102(c), which speaks only to the interstate compacts and says in relevant part:

> The consent of the Congress is hereby given to two or more States to negotiate and enter into agreements or compacts, not in conflict with any law or treaty of the United States, for (1) cooperative effort and mutual assistance for the prevention and control of air pollution and the enforcement of their respective laws relating thereto, and (2) the establishment of such agencies, joint or otherwise, as they may deem desirable for making effective such agreements or compacts. No such agreement or compact shall be binding or obligatory upon any State a party thereto unless it has been approved by Congress.[101]

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[99] *See, e.g.*, CAA section 101(b)(4), 42 U.S.C. § 7401(b)(4) (declaring that purpose of the CAA is "to encourage and assist the development and operation of regional air pollution prevention and control efforts").

[100] *Id.* § 7402(a).

[101] 42 U.S.C. § 7402(c). Section 102(c) includes a third and final sentence: "It is the intent of Congress that no agreement or compact entered into between States after November 21, 1967, which relates to the control and abatement of air pollution in any air quality control region, shall provide for participation by a State which is not include (in whole or in part) in such air quality control region." The reference to "air quality control region[s]" makes clear that congressional intent regarding this sentence concerns NAAQS pollutants. *See id.* § 7407(b)(1) (defining air quality control region). Because air quality control regions concern the attainment and maintenance of the NAAQS, and there are no air quality control regions under CAA section 111(d), EPA reasonably interprets this sentence as having no bearing on multi-state plans developed pursuant to this rule.

To the extent that section 102(c) is ambiguous, the EPA reasonably interprets this provision as clarifying that Congress's encouragement of interstate cooperation in sections 102(a) and 102(c) does not equate to congressional consent to compacts where necessary under the Compact Clause. Because the multi-state plans envisioned under this rule do not require congressional consent under the Compact Clause, they accordingly do not require special congressional action under section 102(c). The EPA's reasonable interpretation is based on the context of section 102(c)—within section 102 and the Act as a whole, as described above—as well as for the additional reasons below.

Adverse commenters tended to ignore the first sentence of section 102(c), which gives express consent for states to "negotiate and enter into" non-preempted compacts "for cooperative effort and mutual assistance for the prevention and control of air pollution and the enforcement of their respective laws relating thereto," as well as to create of compact entities that help effectuate such arrangements.[102] Members of Congress have accurately noted that the provision purports to grant consent in some instances where consent is not required.[103] This may be because the provision was initially adopted in 1955, and has not been revisited since two landmark Supreme Court opinions clarifying when the Compact Clause requires congressional consent.[104] As discussed above, and in those cases, the Compact Clause simply does not apply to all agreements between states, almost all of which are for cooperative effort and mutual assistance in addressing a shared concern. Accordingly, it is perhaps unsurprising that members of Congress have suggested that section 102(c) is "merely a restatement of the general constitutional provision applicable to all compacts (art. I, sec. 10)...."[105]

Additionally, the second sentence of section 102(c) does not prohibit states from engaging in *any* "cooperative efforts and mutual assistance" regarding air pollution. Rather, it only withholds consent from *agreements or compacts* to effectuate those purposes if "such agreements or compacts" are "binding or obligatory" upon a compacting state. Whether an agreement has a power to bind a state—and thus the limit the state's sovereign authority—is one indicia of a constitutional compact.[106]

Section 102(c) is not, as some individuals have suggested, intended to preempt a broader range of interstate agreements than would be prohibited under the Compact Clause. Courts apply a presumption against preemption in this context, and Congress has spoken clearly in other parts

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[102] *Id.* § 7402(c).
[103] H.R. Rep. No. 728, at 23–24, 30 (1967) (recommending the deletion of section 102(c) because, *inter alia*, "States do not require the consent of the Federal Government to enter into negotiations").
[104] *See U.S. Steel Corp. v. Multistate Tax Comm'n*, 434 U.S. 452 (1978); *New Hampshire v. Maine*, 426 U.S. 363 (1976).
[105] H.R. Rep. No. 728, at 23–24, 30 (1967) (recommending the deletion of section 102(c) because, *inter alia*, "States do not require the consent of the Federal Government to enter into negotiations").
[106] *See U.S. Steel Corp.*, 434 U.S. at 468; *cf. West Virginia ex rel. Dyer v. Sims*, 341 U.S. 22 (1951) (applying contract law estoppel principles under an interstate compact).

of the Act where it intended to preempt otherwise lawful state action.[107] Furthermore, Congress's titling of section 102(c) ("Consent of Congress to compacts") mirrors the phraseology of the Compact Clause itself ("Consent of Congress"). Additionally, if Congress had intended to expressly preempt certain "binding or obligatory" interstate agreements and compacts, it likely would have said so in the first sentence of section 102(c), which uses preempting language to preclude states from entering into arrangements "in conflict with any law or treaty of the United States...."[108]

Alternatively, even if section 102(c) unambiguously preempts a further range of conduct than is covered by the Compact Clause—which it does not—it is inapplicable to multi-state plans under this rule for another reason: Section 102(c) only withholds congressional consent from "agreements or compacts" that are "binding or obligatory" upon party states, and multi-state plans are not binding or obligatory agreements or compacts between states.[109] As explained above, multi-state plans that adopt a joint goal or allow for interstate emission trading under this rule are merely a coordinated sets of coordinated single-state plans. The fact that states may reach informal understandings prior to simultaneously submitting their plans does not render that mutual understanding itself "binding or obligatory upon any State a party thereto…." Rather, the only direct legal effect stems from the act of submitting the plans to EPA for approval: Depending on whether the applicable state plan is satisfactory, submitting a state plan can obviate federal regulation of sources within the state.[110] This legal consequence is the same whether a state submits its plan in isolation, or in coordination with other states as part of a "multi-state" plan.

D. Just Compensation Clause

Several commenters claim that this rule unconstitutionally takes private property in violation of the Takings Clause of the Fifth Amendment.

The EPA has considered commenters' hypothetical takings claims but, for the reasons set forth below, has not altered this rule as a result. The EPA disagrees that this rule constitutes a taking within the meaning of the Fifth Amendment. The EPA also disagrees that it is likely this rule will lead to widespread regulatory takings that require compensation.

The Takings Clause of the Fifth Amendment prohibits the federal government from taking "private property… for public use, without just compensation."[111] Federal courts have explained that, broadly speaking, "The purpose of the Takings Clause is to prevent 'Government from forcing some people alone to bear public burdens which, in all fairness and justice, should

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[107] *See, e.g.*, *Engine Mfrs. Ass'n v. S. Coast Air Quality Mgmt. Dist.*, 541 U.S. 246 (2004) (interpreting 42 U.S.C. § 209(a)).
[108] *Compare* 42 U.S.C. § 7402(c), *with* U.S. Const. art. VI, cl. 2.
[109] Some commenters appear to assert that section 102(c) prohibits interstate agreements that are binding on sources. The text of section 102(c) refers to effects "upon any State a party thereto," and thus makes clear that is not the case.
[110] CAA section 111(d)(2), 42 U.S.C. § 7411(d)(2).
[111] U.S. Const. amend. V.

be borne by the public as a whole.'"[112] The Federal Circuit has developed a two-part test for determining whether "fairness and justice" require compensation for the burdens imposed by a particular government action:

> First, as a threshold matter, the court must determine *whether the claimant has established a property interest for purposes of the Fifth Amendment*. This is because only persons with a valid property interest at the time of the taking are entitled to compensation. […]
>
> Second, after having identified a valid property interest, the court must determine *whether the government action at issue amounted to a compensable taking of that property interest*.[113]

Before addressing the substance of commenters' claims, however, it is worth noting that the remedy for an uncompensated taking is to provide the "just compensation" required by the Takings Clause—not to invalidate or withhold implementation of the government action—unless that remedy has been expressly withdrawn by Congress. Thus, even assuming *arguendo* that private entities can (1) identify a compensable property interest that could be subject to a taking, and (2) demonstrate that a regulatory taking has occurred, some commenters still miss the mark by claiming that this rule must accordingly be invalidated as "unconstitutional." As the Supreme Court has explained, "Equitable relief is not available to enjoin an alleged taking of private property for a public use, duly authorized by law, when a suit for compensation can be brought against the sovereign subsequent to the taking."[114] The Tucker Act provides the avenue for aggrieved parties to seek compensation under federal statues like the Clean Air Act.[115] Furthermore, because the takings claims hypothesized by commenters would likely exceed $10,000 in amount, exclusive jurisdiction over such claims (should they materialize) would be in the United States Court of Claims,[116] with initial appellate review in the Federal Circuit.[117] Nor would the pendency of takings claims in those courts justify delaying implementation of this rule, given that the "Fifth Amendment does not require that compensation precede the taking."[118]

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[112] *See, e.g.*, *Huntleigh U.S.A. Corp. v. United States*, 525 F.3d 1370, 1377 (Fed. Cir. 2008) (quoting *Penn. Cent. Transp. Co. v. City of N.Y.*, 438 U.S. 104, 123 (1978)).
[113] *Huntleigh U.S.A. Corp. v. United States*, 525 F.3d 1370, 1378 (Fed. Cir. 2008) (emphasis added) (internal citations and quotations omitted); *see Hearts Bluff Game Ranch, Inc. v. United States*, 669 F.3d 1326, 1329 (Fed. Cir. 2012) (same).
[114] *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1016 (1984) (citing *Larson v. Domestic Foreign Commerce Corp.*, 337 U.S. 682, 697 n.18 (1949)).
[115] *See Ruckelshaus*, 467 U.S. at 1016 (holding that the Tucker Act applies to private property taken pursuant to a federal statute, unless the statute withdraws Tucker Act applicability).
[116] *See* 28 U.S.C. § 1346(a)(2); *Transcapital Fin. Corp. v. Director, Office of Thrift Supervision*, 44 F.3d 1023, 1025 (D.C. Cir. 1995) (noting that federal district courts do not have such jurisdiction).
[117] *See* 28 U.S.C. § 1295(a)(3).
[118] *Ruckelshaus*, 467 U.S. at 1016 (citing *Hurley v. Kincaid*, 285 U.S. 95, 104 (1932)).

Turning to the Federal Circuit's two-step test for determining when compensation is required by the Takings Clause of the Fifth Amendment, the first step is for commenters to identify a compensable property interest subject to the alleged taking. We agree with commenters that a property interest may be in real property, tangible personal property, or intangible personal property. However, many of the purported property interests identified by commenters have been rejected by courts. To take just one example, frustration of business interests does not form the basis of a takings claim, particularly when the alleged taking comes as a result of regulations directed at a third party.[119] Here too, many commenters appear to acknowledge that this rule does not itself regulate affected EGUs, but is merely establishes the framework for state plans to do so.[120] The fact that federal law directed at Party A may "drastically reduce[] the demand" for a Party B's services—and thus "result[] in adverse economic consequences" for Party B—does not mean that the federal government has effectuated a "taking" of Party B's property.[121] Nor have commenters cited any precedent for the proposition that affected EGUs or coal companies have a property interest in the being able to emit CO_2 without regulation. Furthermore, courts have held that, "Where a citizen voluntarily enters into an area which from the start is subject to pervasive Government control, a property interest is likely lacking."[122]

Assuming *arguendo* that legitimate property interests do exist, the second step of the Federal Circuit's framework requires consideration of whether the government action (*i.e.*, this rule) amounts to a compensable taking of those property interests. A takings claim can be based on the theory of physical taking, a "total regulatory taking," a *Penn Central* regulatory taking, or certain types of land exactions.[123] Commenters do not claim that this rule—or applicable 111(d) plan developed under this rule—would result in a physical taking.[124] Rather, they claim that this rule will lead to widespread, uncompensated regulatory takings in violation of the Takings Clause of the Fifth Amendment.

There are two types of regulatory takings relevant here. Under *Lucas v. South Carolina Coastal Council*, just compensation is required for regulations that "completely deprive an owner of '*all* economically beneficial us[e]'" of property, "except to the extent that 'background principles of nuisance and property law' independently restrict the owner's intended use of the

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[119] *See, e.g.*, *Huntleigh USA Corp. v. United States*, 525 F.3d 1370, 1379–81 (Fed. Cir. 2008) (discussing cases); *Omnia v. United States*, 261 U.S. 502 (1923).
[120] Nor do the emission guidelines restrict the use of real property of EGU owners, or of coal reserves.
[121] *See Huntleigh USA Corp.*, 525 F.3d at 1380.
[122] *Hearts Bluff Game Ranch, Inc. v. United States*, 669 F.3d 1326, 1330 (Fed. Cir. 2012).
[123] *Lingle v. Chevron U.S.A. Inc.*, 125 S. Ct. 2074, 2087 (2005) (describing the theories of takings claims).
[124] A physical taking involves the government physically taking possession of an interest in property. *Tahoe-Sierra Pres. Council v. Tahoe Reg'l Planning Agency*, 535 U.S. 302, 323 (2002); *Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982).

property."[125] *Lucas* applies to a "relatively narrow" category of government regulation.[126] By contrast, regulatory challenges are ordinarily governed by the standards set forth in *Penn Central Transportation Co. v. New York City*.[127] That approach requires a balancing of factors including:

> ... "the economic impact of the regulation on the claimant and, particularly, the extent to which the regulation has interfered with distinct investment-backed expectations." In addition, the "character of the governmental action" -- for instance whether it amounts to a physical invasion or instead merely affects property interests through "some public program adjusting the benefits and burdens of economic life to promote the common good" -- may be relevant in discerning whether a taking has occurred.[128]

Assessments of regulatory takings claims are not ordinarily done in the abstract: "[A] takings claim must be ripe,"[129] and commenters' hypothetical takings claims are not.

Contrary to many commenters' assertions, this rule does not establish emission standards for any affected EGU. This rule does not require EGUs to retire, nor does it require EGUs to reduce utilization. This rule does not impose any regulatory requirements on EGUs at all. Rather, emission standards applicable to affected EGUs will be found in as-yet undeveloped state or federal plans.[130] This rule—the only regulatory action present at this stage—merely establishes (1) state-specific CO_2 goals reflecting CO_2 performance rates based on the BSER, and (2) guidelines for the development, submittal and implementation of state plans that will implement those CO_2 performance rates.

As noted throughout the preamble, both states and utilities have substantial flexibility and latitude in the manner of achieving the emission reductions resulting from implementation of these guidelines. Accordingly, it is simply too early in the process to claim that any takings will necessarily materialize. For example, it is not yet known what emission standards will apply to any specific EGUs; or whether such standards will apply by virtue of a state or federal plan;[131] or how individual EGUs will otherwise comply with the emission standards (including whether the

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[125] *Lingle v. Chevron U.S.A. Inc.*, 125 S. Ct. 2074, 2081 (quoting *Lucas v. South Carolina Coastal Council*, 505 U.S. 1003, 1019, 1026–32 (1992)) (emphasis and second alteration in original).
[126] *Id.*
[127] 438 U.S. 104 (1978).
[128] *Lingle*, 125 S. Ct. at 2081–82 (quoting *Penn Central*, 438 U.S. at 124).
[129] *Palazzolo v. Rhode Island*, 533 U.S. 606, 618 (2001) (citing *Williamson Cnty. Reg'l Planning Comm'n v. Hamilton Bank of Johnson City*, 473 U.S. 172 (1985)).
[130] *See* 42 U.S.C. § 111(d)(1), (2).
[131] This is an important distinction given that commenters' assert takings under the Fifth Amendment, which applies only to the federal government, whereas the Clause applies to state governments through the Fourteenth Amendment. *See Chicago, B. & Q. R. Co. v. Chicago*, 166 U.S. 226 (1897).

future applicable plan will allow EGUs to acquire credits or allowances to comply).[132] In the takings context, it is important to wait for the final decision affecting a regulated entity, as the U.S. Supreme Court has explained in the context of land-use regulations:

> [A] takings claim challenging the application of land-use regulations is *not ripe unless the government entity charged with implementing the regulations has reached a final decision regarding the application of the regulations to the property at issue*. A final decision by the responsible state agency informs the constitutional determination whether a regulation has deprived a landowner of all economically beneficial use of the property [under *Lucas*], or defeated the reasonable investment backed expectations of the landowner to the extent that a taking has occurred [under *Penn Central*].[133]

This importance of waiting for facts to develop is partially because determining the existence of a taking is, "essentially an 'ad hoc, factual' inquiry."[134] It is thus "particularly important" that courts not decide constitutional takings claims "except in an actual factual setting that makes such a decision necessary."[135] The weight of the *Penn Central* factors—and thus the outcome of the balancing test—turns on critical facts that can differ between EGUs, and will necessarily depend on an assessment of emission standards eventually applicable to an EGU through (currently non-existent) state or federal plans.[136] (For the same reasons, it is too early for

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[132] The fact that EPA's modeling predicts that some EGUs will choose to retire as a result of this rule does not make this rule a categorical *Lucas*-style regulatory taking as to those EGUs. Some EGU owners or operators might choose to retire the EGU even though they could have complied with emission standards in a state plan (perhaps even by purchasing allowances), simply because of economic decisions about compliance costs or that their own investment-backed expectations in the EGU have already been fulfilled. This reinforces the importance of considering each situation on a case-by-case basis, as described below.

[133] *Palazzolo v. Rhode Island*, 533 U.S. 606, 618 (2001) (emphasis added) (internal quotations and citations omitted).

[134] *See Ruckelshaus*, 467 U.S. at 1005 (quoting *Kaiser Aetna v. United States*, 444 U.S. 164, 175 (1979)).

[135] *Hodel v. Va. Surface Mining & Reclamation Assn., Inc.*, 452 U.S. 264, 294–95 (1981).

[136] For example, the "economic impact" factor could differ dramatically depending on whether a hypothetical emission standard results in 1% reduced utilization versus 99% reduced utilization. Similarly, the utility power sector—"an industry that has long been the focus of great public concern and significant government regulation"—should have expected the substantial probability that the Clean Air Act would be used to regulate CO_2. *Cf. Ruckelshaus*, 467 U.S. at 1008–09 (holding that, given the highly-regulated nature of the pesticide industry, pesticide manufacturers had "no basis for a reasonable investment-backed expectation" that data submitted to EPA would remain confidential under the Trade Secrets Act, even when EPA had not previously taken a position on disclosure of certain pesticide-related data). Nevertheless, the possibility exists that some EGUs within this highly regulated industry can, because of unique factual circumstances, demonstrate the existence of reasonable investment-backed expectations. At this stage of the process, however, all that exists are hypothetical state plans applying hypothetical emission standards against hypothetical EGUs with hypothetical backgrounds.

commenters to claim that they have been partially or fully deprived of a property interest in coal-reserves, or of the real property where affected EGUs are located.[137])

The prematurity of these takings arguments are further evidenced by the separate requirement in Takings Clause cases that parties must typically avail themselves of any opportunities to "obtain administrative relief," which might result in "a mutually acceptable solution" that would "obviat[e] the need to address the constitutional questions."[138] EGUs cannot pursue administrative relief from emission standards that do not exist. All that exists are hypothetical state plans applying hypothetical emission standards against EGUs with hypothetical investment-backed expectations. Commenters' taking arguments are simply not ripe.

XI. Examples of Reduced Generation

This section supports Section V.B.5 of the preamble by providing additional examples of regulations and rulemakings that incorporate reduced production by individual sources as a method for achieving emissions limitation, as well as permits in which fossil fuel-fired EGUs accepted limits on generation to achieve emissions limitations.

A. Limits on Potential to Emit

Stationary sources that emit or have the potential to emit a pollutant equal to or above specified major source thresholds are subject to major source requirements under the CAA. *See, e.g.*, CAA §§ 302(j) (defining "major stationary source" and "major emitting facility"), 112(a)(1) (defining "major source" with respect to hazardous air pollutants), 169(1) (defining "major emitting facility" for purposes of prevention significant deterioration [PSD] permitting). For this reason, the determination of a source's potential to emit, or PTE, often plays a critical role in determining what CAA requirements apply to a source. PTE is a significant factor in determining applicability of major source requirements for the program to control hazardous air pollutants (HAPs) under CAA § 112, the operating permits program under title V of the CAA, the PSD permitting program under part C of title I, and Nonattainment New Source Review (NNSR) permitting program under part D of title I. *See* CAA §§ 112(a)(1), 112(d)(1), 165(a), 169(1), 172(c)(5), 173(a) & (c), 501(2), 502(a), 302(j).

EPA regulations similarly make clear that PTE is a significant factor in determining applicability for certain CAA programs. For example, the applicability provisions for the federal PSD permitting program state that PSD requirements apply to construction of "any new major stationary source" in an area designated as attainment or unclassifiable, 40 CFR 52.21(a)(2), and define "major stationary source" as a stationary source that "emits or has the potential to emit" at least 100 tons per year for any source in a listed source category or 250 tons per year for any source, 40 CFR 52.21(b)(1)(i)(a-b). *See also* 40 CFR 70.3(a)(1) and 71.3(a)(1) (major source applicability under the regulations for the title V permitting programs); 40 CFR 70.2 and 71.2

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[137] *Cf. Hodel*, 452 U.S. at 296–97 & nn.37–38 (rejecting a facial challenge to a federal statute that "does not categorically prohibit coal mining" or "purport to regulate alternative uses to which coal-bearing lands may be put").
[138] *Hodel*, 452 U.S. at 297.

(definition of “major source” for title V, which includes PTE thresholds that qualify a source as a major source if exceeded).

Not surprisingly, given its role in these CAA programs, PTE is defined several places in the EPA’s regulations, and these regulations expressly recognize that certain sources may take enforceable restrictions on utilization, specifically including limitations on hours of operation. The regulations for the PSD program for permits issued under federal authority, for instance, define “potential to emit” as:

> the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and *restrictions on hours of operation* … shall be treated as part of its design if the limitation or the effect it would have on emissions is federally[139] enforceable. …

40 CFR 52.21(b)(4) (regulations for federal PSD permitting program) (emphasis added). Several other CAA programs have materially similar PTE definitions. *See* 40 CFR 51.166(b)(4) (addressing SIP-approved PSD programs), 51.165(a)(1)(iii) (addressing SIP-approved NNSR programs), 70.2 (addressing title V operating permit programs), and 63.2 (hazardous air pollutants). As the EPA’s Environmental Appeals Board, or EAB, has summarized, “PTE reflects a source’s maximum emissions capacity considering the application of any emission control equipment, or other capacity-limiting restrictions, that effectively and enforceably limit emissions capacity.”[140]

For decades, the EPA has recognized that sources that would otherwise exceed the major source threshold for a pollutant may accept limits to reduce their capacity to emit that pollutant and to consider those limits in calculating PTE for that pollutant, so long as those limits satisfy enforceability criteria.[141] In this way, if the source accepts an enforceable limit that restricts its

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[139] Although the federal definition of PTE for PSD includes the term "federally enforceable," EPA has clarified that the term "federally enforceable" as used in relation to the definition of PTE for the federal PSD program in 40 C.F.R. 52.21(b)(4) should be read to mean "federally enforceable or legally and practicably enforceable by a state or local air pollution control agency." Memorandum from John Seitz, Director, Office of Air Quality Planning and Standards, and Robert Van Heuvelen, Director, Office of Regulatory Enforcement, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit* at 3 (Jan. 22, 1996), available at http://www.epa.gov/region07/air/nsr/nsrmemos/pottoemi.pdf. The term "federal enforceability" has also been interpreted to require practical enforceability. *See, e.g., In re Shell Offshore, Inc., Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, 13 E.A.D. 357 at 394, n.54 (EAB 2007).

[140] *In re Shell Offshore, Inc.*, 15 E.A.D. __ , Slip. Op. at 17 (EAB 2012) (citations omitted).

[141] *See, generally*, Memorandum from Terrell Hunt, Assoc. Enforcement Counsel, U.S. EPA, & John Seitz, Director, Stationary Source Compliance Div., U.S. EPA, *Guidance on Limiting Potential to Emit in New Source Permitting*, at 1-2, 6 (June 13, 1989), (“*1989 PTE Guidance*”), available at http://www.epa.gov/region07/air/nsr/nsrmemos/lmitpotl.pdf; Memorandum from John Seitz, Dir., Office of Air Quality Planning & Standards, U.S. EPA, & Robert Van

capacity to emit a pollutant below the relevant threshold, the source avoids triggering major source obligations for that pollutant and obviates the associated requirements. This type of PTE limit is frequently called a synthetic minor limit, and it has become a well-established tool under several major source CAA programs.[142] The use of such PTE limits for sources has been recognized by the EPA in guidance documents,[143] rulemaking notices,[144] and orders signed by

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Heuvelen, Dir., Office of Regulatory Compliance, to EPA Reg'l Air Div. Dirs., *Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)* (*"Options for Limiting PTE"*) (Jan. 25, 1995), available at http://www.epa.gov/region7/air/title5/t5memos/ptememo.pdf.

[142] *See, e.g., In re Shell Offshore, Inc.*, 15 E.A.D. __ , Slip. Op. at 18 n.15 (EAB 2012) (quoting a definition of "synthetic minor" in EPA guidance and prior EAB decisions). *See also* 40 CFR 49.152 (defining "synthetic minor source" for purposes of EPA's minor new source review permitting program for sources on Indian Country).

[143] *See, e.g., 1989 PTE Guidance* at 1-2; *Options for Limiting PTE* at 1-2; U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 8 (Mar. 2011), EPA-457/B-11-001, available at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

[144] *See, e.g.*, 45 FR 52689 (Aug. 7, 1980) (NSR rulemaking noting that availability of PTE limits in permit conditions addressed concerns raised concerning peak load units, among others); 67 FR 80188 (Dec. 31, 2002) (NSR rulemaking); 61 FR 34,211-12 (July 1, 1996) (Title V Part 71 rulemaking).

EPA Administrators responding to petitions for objection to title V permits,[145] by the EAB in considering permit challenges,[146] and by federal courts.[147]

Thus, the EPA and state and local air permitting authorities generally have broad authority to establish such capacity-limiting restrictions for sources that request them, as long as the restrictions are adequately enforceable. These restrictions may, generally speaking, be established through a variety of mechanisms, including rules, general permits, and source-specific permits.[148] Accordingly, the use of PTE limits or synthetic minor limits for stationary sources is widely available and well accepted by both air agencies and sources.

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[145] *See, e.g., In re Orange Recycling and Ethanol Production Facility, Pencor Masada Oxynol, LLC*, Petition No. II-2001-05, at 4-10 (April 8, 2002), available at: http://www.epa.gov/Region7/air/title5/petitiondb/petitions/masada-2_decision2001.pdf (denying petition's request to object to title V permit based on alleged flaws with PTE limits); *In re Columbia University*, Petition No.: II-2000-08, at 33-35 (Dec. 16, 2002), available at: http://www.epa.gov/Region7/air/title5/petitiondb/petitions/columbia_university_decision2000.pdf (recognizing availability of PTE limits, but granting petition's request to object to title V permit where PTE limits were not adequately enforceable); *In re Hu Honua Bioenergy LLC*, Petition No.: IX-2011-1, at 9-14, 16-19 (Feb. 7, 2014), available at http://www.epa.gov/Region7/air/title5/petitiondb/petitions/hu_honua_decision2011.pdf (recognizing availability of PTE limits and granting petition's request to object to title V permit for proposed bioenergy electricity generating facility where PTE limits for criteria pollutants and HAPs were not adequately enforceable); *In the Matter Of Cash Creek Generation, LLC*, Petition No. IV-2010-4 at 14-15 (June 22, 2012), available at http://www.epa.gov/Region7/air/title5/petitiondb/petitions/cashcreek_response2010.pdf (granting in part and denying in part requests for objections based on alleged flaws in PTE limits for a new coal gasification facility and co-located natural gas combined cycle plant). In granting objections in some of these title V orders, the EPA did not in any way diminish the viability of a PTE limit as a means of restricting utilization to ensure compliance. Rather, these objections were based on specific flaws that arose in these particular permitting actions.

[146] *See, e.g., In re Shell Offshore, Inc.*, 15 E.A.D. __ , Slip. Op. at 18 n.15 (EAB 2012) (citing *In re Shell Offshore, Inc., Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, 13 E.A.D. 357, 366 (EAB 2007) and *In re Peabody Western Coal Co.*, 12 E.A.D. 22, 26 & n.11, 31. (EAB 2005)).

[147] *See, e.g., United States v. Louisiana-Pacific Corp*., 682 F. Supp. 1122, 1132-33 (D. Colo. 1987); *Weiler v. Chatham*, 392 F.3d 532 (2d Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels.").

[148] Memorandum from Kathie A. Stein, Director, Air Enforcement Division, Office of Enforcement and Compliance Assurance, to Regional Air Directors, *Guidance and Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits*, at 2-5 (Jan. 25, 1995), available at http://www.epa.gov/region07/air/title5/t5memos/potoem.pdf; *Options for Limiting PTE* at 3-5.

One well-established means of establishing a PTE limit or synthetic minor limit is by taking an enforceable restriction that limits utilization, such as a limit on the hours of operation of an emissions unit. Such PTE limits that restrict hours of operation are particularly relevant for the § 112 program and the title V, PSD, and NNSR permitting programs. The implementing regulations for those programs specifically provide for such limits, and treat them as equivalent to other enforceable restrictions on emissions, such as requirements for pollution control equipment. As noted above, in relevant part, EPA regulations provide that "[a]ny physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and *restrictions on hours of operation*" is considered in determining PTE "if the limitation or the effect it would have on emissions" is enforceable as a legal and practical matter. 40 CFR 52.21(b)(4) (regulations for federal PSD permitting program) (emphasis added). The other CAA programs mentioned above have materially similar provisions in the corresponding PTE definitions.[149] Under these regulatory provisions, a source can take an enforceable limitation on hours of operation that has the effect of restricting actual emissions below the relevant threshold, and by complying with that limit, the source also complies with the CAA by avoiding triggering the corresponding HAP, PSD, NNSR, or Title V requirements. Such a limit on the hours of operation would also restrict utilization. By acknowledging that PTE limitations include both "air pollution control equipment" and "restrictions on hours of operation," these regulations treat reduced utilization and emission controls as equally cognizable means of restricting potential emissions and avoiding CAA obligations.

Furthermore, the EPA has also specifically recognized reduced utilization, particularly limits on the hours of operation, as a mechanism to limit PTE in various documents. In a memorandum setting forth types of restrictions that may limit PTE, for example, the EPA stated "[r]estrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, *hours of operation*, or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level."[150] As with the regulatory provisions discussed above, this statement treats restrictions on hours of operation and requirements to install pollution controls as comparable means of reducing capacity and limiting potential emissions. The EAB has likewise acknowledged the EPA's authority to impose limits on hours of operation to serve as a PTE limit.[151] Federal courts have also determined that limits on the hours of

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[149] *See* 40 CFR 51.166(b)(4) (addressing SIP approved PSD programs), 51.165(a)(1)(iii) (addressing SIP approved NNSR programs), 70.2 (addressing title V operating permit programs), and 63.2 (hazardous air pollutants). The EPA, or a tribal agency operating under delegation, also has authority to issue synthetic minor permits to sources in Indian Country under 40 CFR 49.158, including synthetic minor HAP permits, and those permit may contain enforceable limitations on the hours of operation or other operational restrictions. *See* 40 CFR 49.152(d) (definitions of PTE and reviewing authority).

[150] *1989 PTE Guidance*, at 6 (emphasis added).

[151] *In re Shell Offshore, Inc.*, 15 E.A.D. __ , Slip. Op. at 25-27 (EAB 2012) (quoting 1989 PTE Memorandum and denying a challenge to an emissions-based PTE limit where, among other things, Petitioners had not addressed the operational limits in the permit issued by EPA, including hourly operational limits on certain activities).

operation are properly considered in the calculation of a source's PTE. *United States v. Louisiana-Pacific Corp*., 682 F. Supp. 1122, 1133 (D. Colo. 1987).

Synthetic minor limits, including limits on utilization, are available for EGUs in the same way as they are for any other stationary source. EPA is aware of numerous instances in which EGUs have taken limits on utilization, and in particular limits on hours of operation, as a means of avoiding triggering particular CAA requirements. Sources may also take such limits to comply with requirements under the CAA. Such limits have been used by EPA when it has acted as the permitting authority for sources[152], as well as by state or local agencies acting in their capacity as permitting authorities.[153] Several examples of such permits are highlighted in this Memorandum. A more extensive list of examples of permits containing such limits is included in supporting tables contained in Section XI.C of this Memorandum. These examples illustrate that taking enforceable limits on utilization is a viable means of complying with, or obviating CAA, obligations for EGUs.

If a source does not take an enforceable limit on hours of operation, its PTE is calculated based on its maximum capacity, which is generally 8760 hours per year (i.e., 24 hours a day multiplied by 365 days a year). Sources may take limits below this level to avoid PSD permitting requirements. For example, Sunbury Generation LP in Pennsylvania obtained a minor new source preconstruction permit, called a plan approval, for a repowering project from the Pennsylvania Department of Environmental Protection in 2013 that limited the hours of operation of three combined cycle combustion turbines that were planned for construction below 8760 hours in any 12 month consecutive period in order to remain below the significance threshold for GHGs. [154] Similarly, Manitowoc Public Utilities in Wisconsin obtained a title V renewal permit that limited the operating hours of the single simple-cycle combustion turbine to

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[152] *See, e.g.,* GHG PSD permit for Shady Hills Generating Station, Permit No. PSD-EPA-R4013 (EPA Region 4, 1/13/2014), Condition IX.B.2 at p. 6 of 14 ("If both EU 005 and 006 [combustion turbines] are constructed, they shall not operate an average of more than 3,390 hours per year per combustion turbine on a 12-month rolling total basis. No single unit shall operate more than 5,000 hours per year on a 12-month rolling total basis. If only one combustion turbine is installed, it shall operate no more than 3,390 hours per year on a 12 month rolling total basis. Permittee shall monitor and record the number of hours each combustion turbine operates monthly and totaled every month for the previous 12 months.").

[153] *See, e.g.,* PSD Permit for Tampa Electric Company, Polk Power Station, Permit No. PSD-FL-263 (Fl. Dept. Env. Prot., 10/8/1999), General Operating Condition 13 at p.15 of 219, ("Maximum allowable hours of operation for each unit are 4,380 hours per year on natural gas and 750 hours per year on fuel oil.")

[154] *See* Plan Approval No. 55-00001E for Sunbury Generation LP (Pa. Dept. Env. Protection, 4/1/2013), Conditions #016 on pp. 24, 32 and 40 of 48 (limiting turbine units to operating no more than 7955, 6920, or 8275 hours in any 12 consecutive month period depending on which of three turbine options was selected); Memorandum from J. Piktel to M. Zaman, *Addendum to Application Review Memo for the Repowering Project* (Pa. Dept. Env. Protection, 4/1/2013) at p. 2 of 10 (noting that source had "calculated a maximum hours per year (12 consecutive month period) of operation for the sources proposed for each of the turbine options in order to remain below the significance threshold for GHGs.").

not more than 194 hours per month, averaged over any consecutive 12 month period, as part of limiting its potential to emit for volatile organic compounds below the title V threshold of 100 tpy, and carbon monoxide, nitrogen oxides and sulfur dioxide below the PSD threshold of 250 tpy.[155]

Similarly, to avoid triggering NNSR requirements for NO_x and VOC, NTE Ohio, LLC obtained a Final Permit-to-Install for the Middletown Energy Center that included utilization limits on the auxiliary boiler (as an annual limit on fuel consumption and emission limits for NOx and VOC)[156] and on the emergency generator (as an annual limit of 500 hours of operation and emission limits for NO_x and VOC),[157] as well as emission limits on the combustion turbine and heat recovery steam generator with duct burners.[158] This permit also contains conditions explaining that the limits on the amount of NO_x and VOC that may be emitted by the auxiliary boiler and the emergency generator are derived from and reflect the limits on utilization of those

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[155] *See* Final Operation Permit No. 436123380-P10 for Manitowoc Public Utilities - Custer Street (Wis. Dept. Nat. Res., 8/19/2013), Condition ZZZ.1.a(1) at p. 9 of 14 (limiting potential to emit) and n. 11 ("These conditions are established so that the potential emissions for volatile organic compounds will not exceed 99 tons per year and potential emissions for carbon monoxide, nitrogen oxides and sulfur dioxide emissions from the facility will not exceed 249 tons per year."). *See also* Analysis and Preliminary Determination for the Renewal of Operation Permit 436123380-P10 (Wis. Dept. Nat. Res., 5/21/2013) at p. 5 of 6 (noting that the "existing facility is a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The existing facility is a minor source under PSD and an area source of federal HAP" and further noting that after renewal, "the facility will continue to be a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The facility will also continue to be a minor source under PSD and an area source of federal HAP.").

[156] *See* Final Permit to Install No. P0116610 for NTE Ohio, LLC (OhioEPA, 11/5/2014), Condition 1.b)(1)d. at p.22 of 87 (imposing synthetic minor to avoid NNSR for NOx and VOC by providing that NOx emissions for the emission unit shall not exceed 3.30 TPY and that VOC emissions shall not exceed 1.50 TPY, both based on a rolling 12-month summation); Condition 1.b)(2)k. at p. 25 of 87 ("The maximum annual fuel consumption for this emissions unit shall not exceed 600,000 MMBtu per rolling, 12-month period. …."); and Condition 1.f)(1)b & e at p. 27-29 of 87 (explaining relationship between the emission limitations and the annual fuel consumption limit correlate).

[157] *Id.*, Condition 3.b)(1)c. at p. 63 of 87 (imposing synthetic minor to avoid NNSR for NOx and VOC by providing that NOx emissions for the emission unit shall not exceed 7.25 TPY and the VOC emissions shall not exceed 0.26 TPY, both based on a rolling 12-month summation); Condition 3.b(2)e. at p. 65 of 87 ("The maximum annual operating hours for this emissions unit shall not exceed 500 hours, based upon a rolling, 12-month summation of the operating hours. …"); and Condition 3.f)(1)b & e at p. 69-70 of 87 (explaining relationship between the tpy emission limitations and the annual fuel consumption limit).

[158] *Id.*, Condition 2.b)(1)b at p. 33 of 87 (imposing synthetic minor to avoid NNSR for NOx and VOC by providing that NOx emissions for the emission unit shall not exceed 88.4 TPY and the VOC emissions shall not exceed 92.3 TPY, both based on a rolling 12-month summation).

units. [159] This demonstrates that emission limits may also restrict utilization, depending on how the emission limit was calculated.

Synthetic minor limits may also be taken to avoid requirements of the title V operating permit program. For example, City Center West in Wisconsin obtained a state operating permit when it proposed to modify its emergency generators so that they could provide electric power to the grid, thus making them peak shaving generators.[160] In that permit, it accepted a limit that restricted each generator to operating no more than 16.66 hours per month, averaged over any 12 consecutive months, in order to keep its PTE for NO_x below the 100 tpy major source threshold for purposes of the title V operating permit program. [161]

For construction that triggers PSD permitting requirements, the CAA requires, among other things, that the proposed new source or major modification be subject to best available control technology (BACT) for each pollutant subject to regulation under the Act that it will emit. CAA § 165(a)(4). Permitting authorities have used limits on utilization as part of establishing BACT limits for EGUs. For example, in the PSD permit for Antelope Elk Energy Center, EPA Region 6 limited the turbine to 4,572 operational hours on a 12 month rolling basis.[162] Likewise, in order to ensure that the Rockgen Energy Center could meet its BACT emission limits for several pollutants, the state permitting authority limited each of the combustion turbine processes to operating less than 3800 hours in any 12 consecutive months, with an additional limit on the hours fired with distillate fuel.[163]

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[159] *Id.*, Condition 1.f)(1)b & e at p. 27-29 of 87, Condition 3.f)(1)b & e at p. 69-70 of 87.

[160] *See* Analysis and Preliminary Determination for the Construction and Operation Permits for the Proposed Modification of Two Diesel Electric Generators for City Center West (Wis. Dept. Nat. Res., 3/12/2007) at p. 3 of 13.

[161] FESOP (Synthetic Minor, Non-Part 70) – Final Permit, Permit No. 113225200-F01 for City Center West (Wis. Dept. Nat. Res., 4/19/2007), Condition I.A.2(2) at p. 4 of 15 ("Each generator may not be operated for more than 16.66 hours per month, averaged over any 12 consecutive months. This limit is proposed by the permittee to be minor for Part 70."). *See also id*. at n.2 ("This limit will keep the facility NO_x potential to emit (PTE) less than 100 tons per year, the Part 70 major source threshold level in ch. 407, Wis. Adm. Code.").

[162] PSD Permit for Antelope Elk Energy Center, Permit No. PSD-TX-1358-GHG, (EPA Region 6, 6/2/2014), Condition III.A.2.d at p. 7 of 14 ("The turbine is limited to 4,572 operational hours on a 12-month rolling total basis."); Condition III.A.2.a at p. 7 of 14 ("The BACT limit of 1,304 lbs of CO2/MW-hr gross output is based on a 4,572 rolling operational hour average basis ….").

[163] Title V Renewal Permit for Rockgen Energy Center, LLC, Permit No. 113308030-P10 (Wis. Dept. Nat. Res., 2/4/2010), Condition I.C.1(1) at p. 29 of 55, ("Each of the three combustion turbine processes (P01, P02, and P03) may not be operated more than 3800 hours in any 12 consecutive months of which not more than 800 hours in any consecutive 12-month period shall be on distillate fuel oil with less than 0.05% sulfur by weight. This condition is necessary to meet the BACT emission limits for sulfur dioxide, carbon monoxide, nitrogen oxides, particulate matter, volatile organic compounds and sulfuric acid (mist).")

In addition, permitting authorities have imposed limits on the utilization of EGUs to protect the NAAQS. For example, a title V renewal permit for Madison Gas & Electric Co.'s Blount Street Generating Station took limits on the operating hours for a boiler in order to protect the NAAQS for nitrogen oxides.[164]

B. Title V permit limits

Among other things, title V of the CAA requires all major stationary sources of air pollution and certain other sources to apply for a title V operating permit that includes emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA. CAA §§ 502(a), 503(a), 503(c), 504(a). The title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements, but does not generally impose new substantive air quality control requirements. The title V program is implemented through regulations promulgated under 40 CFR part 70 for programs implemented by state and local agencies and tribes, and 40 CFR part 71 for programs generally implemented by the EPA.

The title V program expressly authorizes permitting authorities to impose operational requirements on sources to ensure compliance with applicable requirements under the CAA, including any requirement under section 111. Section 504(a) of the CAA requires in pertinent part that each permit issued under title V "shall include enforceable emission limitations and standards … and such other conditions as are necessary to assure compliance with applicable requirements" under the CAA. "Emission limitation" is defined in CAA § 302(j), in relevant part, as "a requirement established by the State or Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including *any requirement relating to the operation* … of a source to assure continuous emission reduction, and *any … operational standard* promulgated under this chapter." (Emphasis added.) The implementing regulations specifically state that title V permits may include "operational requirements and limitations," and makes clear that those operational requirements can "assure compliance with … applicable requirements…."[165] The regulations define "applicable requirements" to include any new source performance standards or other requirement under CAA § 111.[166]

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[164] Title V Renewal Permit for Madison Gas & Electric Co. - Blount Street Generating Station, Permit No. 113004430-P20 (Wis. Dept. Nat. Res., 6/30/2015), Condition I.A.3.1 at p. 6 of 75 ("The operating hours for boiler B22 may not exceed 5,100 hours during each 12 consecutive month period.[FN 1]." FN 1 states: "The operating hour limitations are necessary to ensure that the national ambient air quality standard for nitrogen oxide is attained and maintained.")

[165] 40 CFR 70.6(a) ("*Standard permit requirements.* Each permit issued under this part shall include the following elements: (1) Emissions limitations and standards, including those *operational requirements and limitations* that assure compliance with all applicable requirements at the time of permit issuance…." (emphasis added)). *See also* 40 CFR 71.6(a) (same).

[166] 40 CFR 70.2 (defining applicable requirement to include "(3) Any standard or other requirement under section 111 of the Act, including section 111(d); …."). *See also* 40 CFR 71.2 (same).

As the EAB has observed, title V permits may function as vehicles for permitting authorities to establish enforceable limits that restrict PTE, thus allowing sources to qualify as synthetic minor sources for major source requirements that would otherwise apply without such a limit.[167] Indeed, the section of this Memorandum above discussing utilization limits in EGU permits and the supporting tables contained in Section XI.C of this Memorandum that contain additional examples of permits with such limits both include several examples of utilization limits that were taken in title V permits. The authority to impose this type of limit provides permitting authorities with a tool to ensure compliance with requirements under the CAA by establishing enforceable requirements that prevent an applicable requirement from being triggered in the first instance. Thus, these types of limits increase flexibility for permitting authorities and for sources that can keep actual emissions below the relevant thresholds, as well as providing an incentive to do so. Some sources, rather than taking such limits in a title V permit, take synthetic minor limits to avoid being subject to requirements under title V, which include permitting requirements and title V fees. Whether the limit is taken *in* a title V permit or *to avoid* title V obligations, however, it illustrates that taking enforceable limits on operations is a viable means for sources such as EGUs to use reduced utilization to comply with, or obviate, CAA obligations.

[167] *In re Shell Offshore, Inc.*, 15 E.A.D. __ , Slip. Op. at 18 (EAB 2012) (citing *In re Peabody Western Coal Co.*, 12 E.A.D. at 31 & n.21 (EAB 2005)).

C. Examples of Permits Requiring Reduced Utilization at EGUs[168]

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
Shady Hills Generating Station	Pasco County, Florida	Peaking plant; permit authorized construction of two simple cycle combustion turbines (natural gas with backup fuel of ULSD fuel oil)	GHG-only PSD permit	PSD-EPA-R4013	EPA Region 4	1/13/2014	Condition IX.B.2: If both EU 005 and 006 [combustion turbines] are constructed, they shall not operate an average of more than 3,390 hours per year per combustion turbine on a 12-month rolling total basis. No single unit shall operate more than 5,000 hours per year on a 12-month rolling total basis. If only one combustion turbine is installed, it shall operate no more than 3,390 hours per year on a 12 month rolling total basis. Permittee shall monitor and record the number of hours each combustion turbine operates monthly and totaled every month for the previous 12 months.	http://www.epa.gov/region4/air/permits/ghgpermits/shadyhills_ghg.html Page 6 of 14
Tampa Electric Company, Polk Power Station	Polk County, Florida	260 MW integrated coal gasification and combined cycle turbine unit; permit added two dual fuel simple cycle combustion turbines	PSD	PSD-FL-263	Florida DEP	10/8/1999	General Operation Requirements 13. Maximum allowable hours of operation for each unit are 4,380 hours per year on natural gas and 750 hours per year on fuel oil. [Rule 62-210.200, FAC, (Definitions – Potential Emissions), 62.212.400, FAC, (BACT Determination)]	http://arm-permit2k.dep.state.fl.us/psd/1050233/000109D2.pdf Page 15 of 219
Antelope Elk Energy Center	Abernathy, Texas	168 MW, peaking and intermediate load plant; permit added one natural gas fired simple cycle combustion turbine	GHG-only PSD	PSD-TX-1358-GHG	EPA Region 6	6/2/2014	Special Permit Conditions – Turbine BACT Requirements III.A.2.d – The turbine is limited to 4,572 operational hours on a 12-month rolling total basis. III.A.2.a – The BACT limit of 1,304 lbs of CO2/MW-hr gross output is based on a 4,572 rolling operational hour average basis, calculated daily using equations for CO2 provided in 40 CFR Part 75, Appendix G, Procedure 2.3 or the CO2 emissions CEMS data 40 CFR Part 75, Appendix F. The Permittee	http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/goldenspread-antelope-final-permit060314.pdf Page 7 of 14.

[168] These examples of permits containing terms that require reduced utilization at EGUs were identified with the assistance of EPA regional staff. Copies of the cited permits are available in the docket for this action.

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
							shall calculate each day a combustion turbine operates, CO2 emissions over the rolling 4,572 hours of operation basis divided by gross electrical output over the same period for comparison to the limit for the combustion turbine.	
Sunbury Generation LP	Snyder County, PA	Repowering of facility by replacing coal fired generation with natural-gas fired combined cycle turbines	Minor new source review precon-struction permit	Plan Approval No. 55-00001E	Pennsylvania DEP	4/1/2013	Condition #016: Pursuant to the best available technology requirements of 25 Pa. Code Sections 127.1 and 127.12, Source ID P181 [turbine] shall not be operated in excess of the following rates: (a) 7,955 hours in any 12 consecutive month period (CMP) if the Siemen[s] F4 option is selected, (b) 6,920 hours in any 12 CMP if the Siemens F5 option is selected, (c) 8,275 hours in any 12 CMP if the GE 7FA.05 option is selected.	N/A Page 24 of 48; see also pp. 32 and 40 of 48 (same for other turbines)
Madison Gas & Electric Co., Blount Street Generating Station	Madison, Dane County, Wisconsin	Natural Gas/Distillate Fuel Oil Boilers	Title V Renewal	113004430-P20	Wisconsin DNR	6/30/2015	Condition I.A.3.1 (1) The operating hours for boiler B22 may not exceed 5,100 hours during each 12 consecutive month period.[FN 1]. [ss. 285.63(1)(b) and 285.65(7), Wis. Stats, s. NR 407.09(2)(d), Wis. Adm. Code] FN 1 states: "The operating hour limitations are necessary to ensure that the national ambient air quality standard for nitrogen oxide is attained and maintained."	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 6 of 75
City Center West	Madison, Dane County, Wisconsin	Peak shaving generators	FESOP (Synthetic Minor, Non-Part 70)	113225200-F01	Wisconsin DNR	4/19/2007	Condition I.A.2(2) [Part of NOx limit] (2) Each generator may not be operated for more than 16.66 hours per month, averaged over any 12 consecutive months. This limit is proposed by the permittee to be minor for Part 70. [s. 285.65(7), Wis. Stats.]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 4 of 15
Rockgen Energy Center, LLC	Christiana, Dane County, Wisconsin	Nominal 525 MW Peak Power Electric Generation Facility	Title V Renewal	113308030-P10	Wisconsin DNR	2/04/2010	Condition I.C.1(1) (1) Each of the three combustion turbine processes (P01, P02, and P03) may not be operated more than 3800 hours in any 12 consecutive months of which not more than 800 hours in any consecutive 12-month period shall be on distillate fuel oil with less than 0.05% sulfur by weight. This condition is necessary to meet the BACT emission limits for sulfur dioxide, carbon monoxide, nitrogen oxides, particulate matter, volatile	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 29 of 55

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
							organic compounds and sulfuric acid (mist). [s. 285.65(7), Wis. Stats.]	
We Energies – Concord Generating Station	Watertown, Jefferson County, Wisconsin	Combustion turbines	Title V Renewal	128065080-P30	Wisconsin DNR	01/15/2013	Condition I.A.7(3) The operation of turbines P01, P02, P03 and P04 combined at less than 75 MW output may not exceed 540 hours/month averaged over any 12-month period, excluding startup/shutdown periods. [s. 285.65(7), Wis. Stats., 05-SDD-320 for P01 and P02, and 08-SDD-104 for P03 and P04]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 18 of 21
Washington Island Electric Cooperative	Washington Island, Wisconsin	Backup electricity generating facility from diesel generators	FESOP (Synthetic Minor, Non-Part 70) - Renewal	415186750-F20	Wisconsin DNR	02/09/2010	Condition I.Z.1.a.(1): The permittee may not burn more than 300,000 gallons of Numbers 1 and 2 distillate fuel in generators P08 and P09, combined, during each 12 consecutive month period.3 [s. 285.65(7), Wis. Stats.] Condition I.Z.2.a.(1): The permittee may not operate generators P03 and P04 for more than 500 hours, each, during each 12 consecutive month period. [s.285.65(7), Wis. Stats.]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 6 of 8
Manitowoc Public Utilities - Custer Street	Manitowoc, Manitowoc County, Wisconsin	Simple cycle combustion turbine	Title V Renewal	436123380-P10	Wisconsin DNR	08/19/2013	Condition I.ZZZ.1.a(1): The operating hours for the single simple-cycle combustion turbine (P01) may not exceed 194 hours per month averaged over any 12 consecutive month period. [s.285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.; 98-RV-153]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 9 of 14
Madison Gas & Electric - West Marinette Facility	Marinette County, Wisconsin	Simple cycle combustion turbine	Title V Renewal	438022420-P10	Wisconsin DNR	08/31/2010	Condition I.A.9.a(1)(a) The total hours of operation of Process B04 [combustion turbine] may not exceed 4,000 hours in any year. Of the total 4,000 hours, the hours fired on distillate fuel oil may not exceed 2,000 hours in any year; and (b) The total hours of operation in the peak power mode may not exceed 100 hours in any year. [s. 285.65(7), Wis. Stats.; Permit #99-RV-136-OP-R1]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 14 of 32
Wisconsin DOA-UW-Stout Power Plant	Menomonie, Dunn County, Wisconsin	23 Emergency generator (9 powered by CI diesel engines and 14 powered by SI natural gas engines)	Title V	617013320-P30	Wisconsin DNR	1/21/2014	(1) Each emergency electric generator in Process P01 shall only be used to provide electricity to the facility if normal electrical service is interrupted and shall be operated no more than 200 hours in any consecutive 12-month period. [s. NR 400.02(56), Wis. Adm. Code, and s. 285.65(3), Wis. Stats.]	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 50
NTE Ohio, LLC – Middletown Energy Center	Middletown, Ohio	Combined cycle turbine	Permit to Install	P0116610	Ohio EPA	11/5/2014	Auxiliary Boiler	http://wwwapp.epa.ohio.gov/dapc/permits_issued/1224365.pdf

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
							Condition 1.b)(1)d. Synthetic Minor to avoid Nonattainment Area New Source Review (NAA-NSR) for NOx and VOC. The NOx emissions shall not exceed 3.30 TPY based on a rolling 12-month summation. The VOC emissions shall not exceed 1.50 TPY based on a rolling 12-month summation. See b)(2)k. Condition 1.b)(2)k. The maximum annual fuel consumption for this emissions unit shall not exceed 600,000 MMBtu per rolling, 12-month period. … Condition 1.f)(1)b.Emission Limitation: NOx emissions shall not exceed 0.011 Lb/MMBtu of heat input, 1.65 pounds per hour, and 3.30 tons per rolling, 12-month period. … The annual emission limitation was developed by multiplying the hourly emission limitation (1.65 pounds per hour) by the maximum annual operating hours (4,000 hours per year) and dividing by 2,000 pounds per ton. The 4000 hours per year value is equivalent to the 600,000 MMBtu, per rolling, 12-month period value. … See also Condition 1.f)(1)a (similar provision for CO); Condition 1.f)(1)c (similar provision for PE, PM10, and PM2.5); Condition 1.f)(1)e. (similar provision for VOC); Condition 1.f)(1)f (similar provision for sulfuric acid mist) <u>Emergency Generator</u> Condition 3.b)(1)c. Synthetic Minor to avoid Nonattainment Area New Source Review (NAA-NSR) for NOx and VOC. The NOx emissions shall not exceed 7.25 TPY based on a rolling 12-month summation. The VOC emissions shall not exceed 0.26 TPY based on a rolling 12-month summation. see b)(2)e. Condition 3.b(2)e. The maximum annual operating hours for this emissions unit shall not exceed 500 hours, based upon a rolling, 12-month summation of the operating hours. …	Pages 22, 25, 27-29, 63, 65, 69-70 of 87; see also 33 for an emissions-based synthetic minor limit on the turbine with heat recovery steam generator, natural gas-fired, including duct burners

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
							Condition 3.f(1)b. Emission limitation NOx emissions shall not exceed 8.92 g/hp-hr, 9.01 Lbs/hr, and 7.25 tons per rolling, 12-month period. … The hourly emission limitation was developed by multiplying the maximum operating load (1475 HP) by the NOx emission factor supplied by the manufacturer (8.92 g/hp-hr) divided by (453.59 g/Lb) to determine the hourly emissions. … The annual emission limitation was developed by multiplying the hourly emission limitation (29.01 Lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Compliance with the rolling, 12-month emission limitation shall be demonstrated by the recordkeeping in d)(1). Condition 3.f(1)e. Emission Limitation: VOC emissions shall not exceed 0.26 tons per rolling, 12-month period. … The annual emission limitation was developed by multiplying the maximum hourly emissions (1.04 Lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Compliance with the rolling, 12-month emission limitation shall be demonstrated by the recordkeeping in d)(1).	
PREPA San Juan	San Juan, Puerto Rico	2 Turbines and 4 Boilers	PSD permit with PSD nonapplic-ability conditions for some pollutants.	Not applicable	EPA Region 2	4/01/2004	Condition XII.3: Both Westinghouse 501 distillate oil fired combustion turbines shall only be allowed to operate for up to 15,000 hours per year. Daily compliance shall be determined by adding the total amount of hours operated by both turbines during each calendar day to the total hours operated by both turbines in the preceding 364 calendar days. Condition XII.3.c: The maximum total fuel use in these four boiler units shall be limited to 173.1 million gallons per year.	http://www.epa.gov/region2/air/permit/PREPA04012004.pdf Page 17 of 30
El Paso Electric Company, Montana Power Station	El Paso, Texas	400 MW peak and intermediate load Electric Power	GHG only PSD	PSD-TX-1209-GHG	EPA Region 6	3/25/2014	BACT Limit: III.A.2.a. The limit of 1,100 lbs of CO2/MWhr gross output is based on …calculate each day a combustion turbine operates, CO2 emissions	http://yosemite.epa.gov/r6/Apermit.nsf/AirP Page 7 of 14

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
		Generation Facility					over the rolling 5,000 hours of operation basis divided by gross electrical output over the same period for comparison to the limit for each combustion turbine. III.A.2.d. Each turbine …is limited to 5,000 operational hours on a 12-month rolling basis which shall include periods of startup and shutdown.	
Burney Mountain Power	Burney, California	Biomass Boiler	PSD	SAC 08-01	EPA Region 9	10/21/2010	Condition X.D.1.b: Operation of the boiler shall not exceed 8,400 hours on a 12-month rolling basis.	http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2009-0966-0026 Page 6 of 13
Fort Pierre Power and Light Plant	Stanley County, SD	Peaking, Diesel Generators	Title V	28.0801-58	South Dakota Dept. of Environ. & Nat. Res.	04/13/2015	10.3 Hourly limit for diesel engines In accordance with ARSD 74:36:05:16.01, the owner or operator shall not operate Unit #1, #2, and #3 for more than a total of 8,112 hours during any 12-month rolling period. The 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values.	http://denr.sd.gov/pdfaq1/28.0801-58_permit_20150413.pdf Page 37 of 37
Madison Generation Plant	Lake County, SD	Peaking, Diesel Generators	Title V	28.0801-43	South Dakota Dept. of Environ. & Nat. Res.	04/07/2015	7.4 Hourly limit for diesel engines In accordance with ARSD 74:36:05:16.01(8), the owner or operator shall not operate Engines #1, #2, #3, #4 and #5 for more than a combined 7,834 hours during any 12-month rolling period. The 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values. The initial startup of the facility shall be the first month of the 12-month rolling period.	http://denr.sd.gov/pdfaq1/28.0801-43_permit_20150407.pdf Page 17 of 38
Northwestern Public Service Company, Yankton	Yankton, SD	Peaking, Diesel Generators	Title V	28.0801-07	South Dakota Dept. of Environ. & Nat. Res.	03/06/2015	7.3 Hourly limit for Unit #4 In accordance with ARSD 74:36:05:16.01(8), the owner or operator shall not operate Unit #4 for more than 1,120 hours each during any 12-month rolling period. The 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values.	http://denr.sd.gov/pdfaq1/28.0801-07_permit_20150306.pdf Page 17 of 37
Basin Creek Equity Partners, Basin Creek	Silver Bow County, MT	Peaking, Natural gas reciprocating internal combustion engines	Title V	OP3211-02	Montana Dept. of Env. Quality	09/04/2011	B.5. Combined RICE operation (9 engines total) shall be limited to a maximum of 34,200 hours during any rolling 12-month time period (ARM 17.8.749).	http://www.deq.mt.gov/airquality/ARMpermits/awm_final_permit.mcpx Page 11 of 40

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
Basin Electric Power Cooperative, Culbertson	Roosevelt County, MT	Peaking, combustion turbine	Title V	OP4256-00	Montana Dept. of Env. Quality	12/14/2010	B.6. Operation of the turbine generator, including startup and shutdown, shall not exceed 3,400 hours per rolling 12-month time period (ARM 17.8.749).	http://www.deq.mt.gov/airquality/ARMpermits/awm_final_permit.mcpx Page 10 of 39
Payson City Corporation – Payson City Power	Utah County, Utah	Peaking; four dual-fuel (NG/oil) internal combustion engines, two serving 2.65-MW electrical generators, one serving a 2.093-MW electrical generator, and one serving a 1.80-MW electrical generator	Title V	4900080004	Utah Dept. of Env. Quality	1/16/2015	Permit condition II.B.6.e (pertaining to the dual-fuel engines): Total hours of operation shall not exceed 12,600 hours per rolling 12-month period for all engines combined. [Origin: DAQE-AN108230006-14, SIP IX.H.3.c]. [R307-110-17(SIP IX.H.3.c), R307-403-8(1)(a)(BACT)]	http://168.178.3.241:8080/DAQ_NOI/DocViewer?IntDocID=79251 Page 23 of 34
Provo City Power - Power Plant	Utah County, Utah	Peaking; four dual-fuel (NG/oil) internal combustion engines, each serving a 2.585-MW electrical generator; two NG-fired boilers, each serving a 9.20-MW electrical generator	Title V	4900018003	Utah Dept. of Env. Quality	10/28/2009	Permit condition II.B.2.c (pertaining to the dual-fuel engines): Combined hours of operation shall be no greater than 48 hours per day for the four engines. [Authority granted under R307-401-8(1)(a)[BACT]; condition originated in DAQE-AN0795006-04].	http://168.178.3.241:8080/DAQ_NOI/DocViewer?IntDocID=50100 Page 16 of 22

Capacity Limits

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
PREPA Costa Sur	Guayanilla Puerto Rico	Two boilers 4 & 5. Each boiler is rated at 3,950.7 MMBTU/hr and can produce 410 MW (820 MW in total).	Revised state construct-ion permit	PFE-31-0810-0455-II-C (in Spanish)	Puerto Rico Envt'l Quality Board	09/20/2010	Condition B.2 provides 5 different operating scenarios for the two boilers: 1) 100% natural gas; 2) 25% natural gas & 75% fuel oil; 3) 50% NG & 50% fuel oil; 4) 75% NG & 25% fuel oil, and 5)100% fuel oil. Each operating scenario has a maximum fuel oil and natural gas restriction limit. The capacity factor for each of the operating scenario is 71%, 65%, 65%, 65%, and 65%, respectively.	Page 3 of 14.

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
AES-Puerto Rico Co-generation Project	Guayama, Puerto Rico	454 MW Circulating Fluidized Bed Boiler-Coal fired.	PSD - Revised Permit	Not applicable	EPA Region 2	08/10/2004	See Condition XVI.6: Maximum Annual Capacity Factor a. AES-PRCP shall not exceed a maximum annual capacity factor of 95% during any period of 12 consecutive months. Compliance will be demonstrated by limiting facility fuel use to a maximum of 40,966,709 MMBtu during any period of 12 consecutive months. AES-PRCP shall maintain fuel use records to demonstrate compliance with this condition. b. "Annual capacity factor" means the ratio between the actual heat input to the steam generating units from fuel use during a period of 12 consecutive calendar months and the potential heat input to the steam generating units from fuels had the steam generating units been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity of 4922.7 MMBtu/hr. Therefore, a maximum annual capacity factor of 95% means fuel use will not exceed 40,966,709 MMBtu during a period of 12 consecutive calendar months.	http://www.epa.gov/region2/air/permit/AES08102004.pdf Page 28 of 31
Great River Energy - Coal Creek Station	McLean County, North Dakota	Base-loaded; two lignite-fired boilers, one rated at 6,015 MMBtu/hr, one rated at 6,022 MMBtu/hr; two liquid fuel fired auxiliary boilers, each rated at 172 MMBtu/hr	Title V	T5-F82006	North Dakota Dept. of Health, Dept. of Air Quality	1/30/2015	Permit condition 3.C: Auxiliary Boilers Annual Capacity Factor: Beginning on the compliance date of NDAC 33-15-22 (40 CFR 63) Subpart DDDDD for existing boilers (January 31, 2016 or as amended), EU3 and EU4 auxiliary boilers shall be limited to an average annual capacity factor of no more than 10 percent to maintain status as limited use boilers as defined in 40 CFR 63.7575. …	http://www.ndhealth.gov/EHS/FOIA/AQPermits/AQPermitOperating.aspx Page 6 of 61
Otter Tail Power Company - Coyote Station	Mercer County, North Dakota	Base-loaded; one lignite-fired cyclone boiler rated at 5,800 MMBtu/hr; one oil-fired auxiliary boiler rated at 202 MMBtu/hr	Title V	T5-F84011	North Dakota Dept. of Health, Dept. of Air Quality	10/2/2013	Permit condition 4.F: In order to maintain limited-use boiler classification as defined by 40 CFR 63 Subpart DDDDD, EU2 shall combust no more than 1,263,943 gallons of No. 2 fuel oil per calendar year, which corresponds to an average annual capacity factor of 10 percent. Periodic tune-ups shall be completed as specified in 40 CFR 63.7540. These requirements shall become effective at the time EU2 must comply with 40 CFR 63 Subpart DDDDD. Applicable Requirement: PTC 13032 and NDAC 33-15-22-03, Subpart DDDDD	http://www.ndhealth.gov/EHS/FOIA/AQPermits/AQPermitOperating.aspx Page 5 of 35

Fuel or Heat Input Limits

Facility name	Location of facility	Type of EGU	Type of permit	Permit number	Permit authority issuing permit	Date permit signed or issued	Text of permit condition containing utilization limit	Web address where permit can be found, if available, and page citation for limit
Wisconsin DOA-UW – Green Bay	Green Bay, Wisconsin	6 Industrial Watertube boilers which burn natural gas and distillate oil	Synthetic minor, non-Part 70	405043540-F20	Wisconsin Department of Natural Resources	2/16/2010	D. Conditions applicable to the entire facility. 1. Synthetic Minor Restrictions [fn 7] (1) The total quantity of natural gas fired by the facility may not exceed 109.6 million Cubic Feet (cf6) per month, averaged over any 12 consecutive month period. [s. 285.65(7), Wis. Stats.] (2) The total quantity of distillate fuel oil fired by the facility may not exceed 109,600 gallons per month, averaged over any 12 consecutive month period. [s. 285.65(7), Wis. Stats.] FN 7 states: These restrictions on fuel use, and the limitations on Nitrogen Oxides emissions when firing natural gas (0.10 lbs/MMBTU) and distillate oil (0.143 lbs/MMBTU) are both necessary for the facility to be considered a synthetic minor source under PSD and Title V. A. [Boiler Limitations] 3. Nitrogen Oxides (1) 0.10 pounds of Nitrogen Oxides per million BTU of heat input when firing natural gas and 0.143 pounds of Nitrogen Oxides per million BTU of heat input when firing distillate fuel oil. [FN2] [s. 285.65(3), and s. 285.65(7), Wis. Stats., 04-DCF-301] FN2 states: This condition, along with the facility restrictions on the quantities of natural gas and distillate fuel oil that may be fired, are necessary to assure that the facility constitutes a synthetic minor source under the Title V and PSD permit programs. These emission rates are based on the AP-42 emission factors of 100 lbs/cf6 for natural gas and 20 lbs/gal3 for distillate oil combustion, in boilers with heat inputs less than 100 MMBTU/hr.	http://dnr.wi.gov/cias/am/amexternal/AM_PermitTrackingSearch.aspx (search by permit number) Page 12 of 15 for restriction on fuel use; Page 6 of 15 for Nitrogen Oxide Emissions Limits
Anita Municipal Utilities	Anita, IA	IC Diesel Engines	Minor new source review preconstruction permit	02-A-375	Iowa Department of Natural Resources	8/22/2002	14. Operating Limits …	Page 6 of 11

							The total amount of fuel used by this unit (EU-11) shall not exceed 189,225 gallons per twelve (12) month rolling period.[169]	

[169] While Caterpillar makes several versions of this generator set, the low fuel consumption version uses 123.2 gal/hr at 100% load (specifications available at http://s7d2.scene7.com/is/content/Caterpillar/17791289. Under that assumption, the 189,225 fuel limit would restrict operations to 1,536 hours (189,225 gal/123.2 gal/hr = 1,536 hrs), which is less than 8760 hours.

C. Cross-state Air Pollution Rule (CSAPR)

In CSAPR, the EPA noted that reducing generation was one of the methods EGUs were expected to use to achieve emission reductions. 76 Fed. Reg. at 48272 ("EPA believes that the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing fuels, ***reducing utilization,*** buying allowances, or any combination of these actions. Interstate trading with assurance provisions provides additional regulatory flexibility that promotes the power sector's ability to operate as an integrated, interstate system and to provide electric reliability.").

D. General state implementation plan (SIP) provisions

Long-standing EPA regulatory requirements for SIPs make clear that reduced production is an accepted type of control strategy for reducing emissions.

Specifically, EPA regulations require SIPs to include a "control strategy,"[170] defined as:

> a combination of measures designated to achieve the aggregate reduction of emissions necessary for attainment and maintenance of national standards including, but not limited to, measures such as:
>
> * * *
>
> (3) Closing or relocation of residential, commercial, or industrial facilities ... [and]
>
> * * *
>
> (8) Any variation of, or alternative to any measure delineated herein.[171]

Reduced production (i.e., in the case of EGUs, reduced generation) would be considered a "variation," under paragraph (8) of the measures in paragraph (3).

XII. Combining Categories

This section provides more information relevant for section IV.E., "Combined Categories and Codification in the Code of Federal Regulations."

Combining the steam generator category and the combustion turbine category is reasonable because the sources in both categories provide the same product, electricity services and, though the integrated grid, operate in conjunction with each other. Moreover, combining them in this rule is consistent with our decision to combine them in the CAA section 111(b) rule for new sources that accompanies this rule. In addition, many of the monitoring, reporting, and verification requirements are the same for both source categories, and, as discussed next, we are codifying all requirements in a single new subpart of the regulations; as a result, combining the two categories into a single category will reduce confusion. Moreover, combining the categories facilitates emission trading between steam generators and combustion turbines by obviating any

[170] 40 C.F.R. § 51.111.
[171] 40 C.F.R. §51.100(n)(8).

legal questions as to whether section 111 authorizes emission trading between sources in different source categories.

XIII. Timetable for Source Compliance

This section provides more information in support of preamble section V., which explains that affected EGUs are able to implement the building blocks on a timetable that allows them to meet their emission performance requirements by 2022 and later without having to incur significant expenditures for the first several years after promulgation of this rule. This same information supports preamble section VIII, which explains that implementation of the building blocks is not expected to cause reliability concerns.

There are a number of instances (cited below) in which the owners or operators of fossil fuel-fired EGUs have retired their plants on short notice, sometimes retiring their plants within a few months of announcing their intention to do so. In some instances, transmission upgrades or reconfigurations were needed to facilitate the retirements. The ability of owners or operators to retire their plants on short notice depends at least in part on the extent to which the plants are being utilized, along with the availability of other generation resources needed to meet load requirements. Even so, these instances illustrate that significant reductions in generation resources can occur over very short periods.

As a result, these instances illustrate that one method of implementing building blocks 2 and 3 -- reduced generation, which is less intrusive than retirement -- should be available to affected EGUs on a timetable that allows them to meet their emission performance requirements by 2022 and later without having to incur significant expenditures for the first several years after promulgation of this rule.

In addition, these instances also demonstrate circumstances in which the electricity system has sufficient resiliency, including the ability to make some types of transmission upgrades and reconfigurations on short notice, to accommodate retirements without raising reliability concerns.

Other examples of units that have retired on short notice are found in the docket for this rulemaking, which include sets of slides provided by PJM. Each month up until the April 16, 2015 compliance date for MATS, and, at present, quarterly, EPA holds a conference call with DOE, FERC and PJM at which PJM updates the agencies on the status of deactivation (retirements) requests. The information provided is usually the date of the request, deactivation date requested, whether there is a reliability concern and if there is, the remedy and when the remedy is complete.

Retirement of Hatfield Ferry 1,2,3 (1590 MW) and Mitchell 2,3 (359 MW) [172]

All of these units were owned by First Energy, which notified PJM on July 9, 2013 that the plants would be retired on October 9, 2013. The retirements entailed 30 transmission upgrades, some of which were previously identified and needed to be accelerated, and some of

[172] https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy-to-deactivate-two-coal-fired-power-plants-in-pennsyl.html

which were new. Most involved small, lower voltage transmission lines, and some were larger, costing tens of millions of dollars. In a few places, lines needed to be reconfigured to address thermal issues. Most transmission upgrades were completed by the time of plant retirements, and the rest were managed with operating procedures. The plants closed on time.

Will County Unit 3 (251 MW) [173]

This unit notified PJM in the fall of 2014 that it would close on April 15, 2015. PJM found no reliability issues with the closure, and the unit closed on schedule.

Walter C. Beckford 5 & 6 (652 units) [174]

The units notified PJM in September of 2014 that it wanted to close as soon as possible. PJM found no issues and the units closed later in September.

XIV. Explanation for Certain Aspects of the EPA's Interpretation of the BSER

This section provides additional support for certain aspects of the EPA's interpretation and application of the BSER, as described in section V. of the preamble.

In this rulemaking, the EPA is determining the BSER on the basis of the relevant source subcategory. For example, the BSER for the fossil fuel-fired steam generator subcategory includes, along with building block 1, substituting lower- and zero- emitting generation for higher-emitting generation, through building blocks 2 and 3. For convenience, the remainder of this discussion will refer only to the steam generator subcategory, and will refer only to building blocks 2 and 3.

Based on its determination of the BSER, the EPA determines the emission performance rate that reflects the degree of emission limitation achievable through the application of the BSER. For the fossil fuel-fired steam generator subcategory, the EPA is determining the emission performance rate to be 1305 lbs CO_2/MWh.

Individual affected EGUs in the source subcategory would be able to achieve the emission standard performance rate, if their state were to impose it as the standard of performance, by undertaking any of a set of measures or actions that apply or implement[175] the BSER. These include purchasing emission reduction credits (ERCs), engaging in bilateral transactions with lower- or zero-emitting units, reducing generation, emissions trading, or undertaking a combination of those measures or actions.

It should be noted that while it would be technically feasible for each affected EGU to substitute part of its generation for lower- or zero-emitting generation in its share of the amounts contemplated for the source category, by reducing a portion of its generation and purchasing ERCs or undertaking other actions, that would not maximize the efficiencies available to each

[173] http://www.powermag.com/nrg-to-shutter-repower-illinois-coal-units-in-modernization-bid/
[174] http://www.cincinnati.com/story/money/2014/08/29/beckjord-plant-shutting-monday/14839437/
[175] In this context, the terms "implement" and "apply" are used interchangeably.

source. The EPA's determination of the BSER for the source category -- in this case, substitution of lower- or zero-emitting generation for higher emitting generation -- does not depend on each individual affected source being able to implement the BSER in precisely the manner that the EPA defined it for the source category as a whole.

Rather, it is sufficient that each affected EGU is *capable* of achieving its emission limit (which, again, EPA calculated on the basis of the degree of emission limitation achievable by the application of the BSER to the source category) by applying or implementing the BSER (which, again, each affected EGU can do by undertaking any of a set of measures or actions).

As just described, our approach complies fully with CAA section 111(d)(1) and (a)(1). These provisions require that the EPA determine the BSER and the related emission performance standard, and that the affected sources be able to achieve the emission performance standard through the application of the BSER. These provisions do not specify how the EPA is to determine the BSER, and as a result, the EPA may determine the BSER on the basis of the source category, as it has done here. The ability of all of the affected EGUs to achieve the emission performance standard by implementing or applying the BSER through the above-described set of measures assures that the EPA's approach is consistent with section 111(d)(1) and (a)(1).

It is useful to present another set of circumstances that, although different from the ones in this rulemaking, illustrate another application of the EPA's approach. Assume that for a source category, the EPA identifies as the BSER an add-on control that, when installed and operated at full capacity, reduces emissions by 90%, but that the EPA determines is of reasonable cost only if applied to half the production. Assume further that it is reasonable to expect that the sources in the source category will engage in emissions trading. In this case, the EPA, in its emission guidelines, would identify the add-on control technology as the BSER, and determine the emission rate for the sources that reflects the degree of emission limitation achievable by reducing emissions by 45% (half of 90%). Each source would be able to achieve its emission rate – which means lowering its emissions by 45% -- by implementing the BSER, which it could do either by (i) installing an add-on control (and reducing its emissions by 90%, and being able to sell emission reduction credits to defray the costs of the add-on control), or (ii) purchasing emission reduction credits or conducting a bilateral transaction with another source to, in effect, jointly implement the add-on control on one of the sources.

XV. Coal-cleaning as a "Beyond-the-unit" measure

This section provides additional explanation for section V.B.3. of the preamble by explaining in more detail how the history of EPA's and Congress's reliance on coal-cleaning as the basis for emission limits under section 111 makes clear that, contrary to the views of some commenters, section 111(a)(1) incorporates "beyond-the-unit" measures.

Some commenters argue that under section 111, Congress never intended to authorize "beyond-the-unit" or "beyond-the-fenceline" measures, and that such measures cannot be considered components of a system of emission reduction. We disagree with these comments, for reasons discussed in section V.B.3 of the preamble, including the point that at least one "beyond-the-unit" measure has been part of the BSER for EGUs for some standards of performance for

decades, and, in fact, for a period of time, was expressly authorized under section 111, namely, pretreatment of fuels. Here we provide a more detailed discussion of this point.

Shortly after the 1970 CAA Amendments, EPA proposed standards of performance for an "initial list of five stationary source categories which contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare."[176] The first category identified in the proposed rule addressed fossil fuel-fired steam generators, for which EPA proposed standards for particulate matter, SO_2, and NO_x.[177]

With respect to SO_2 emissions, EPA proposed to restrict emissions in excess of 0.8 ppm BTU heat input when liquid fuel (*i.e.*, oil) is burned and 1.2 ppm BTU heat input when solid fuel (*i.e.*, coal) is burned.[178] The stringency of this standard was based upon consideration of "the availability and cost of fuels and control techniques and to effects on the economics of producing electric power."[179] In particular, one of EPA's major considerations was "[t]he desirability of setting [SO_2] standards that would allow the use of low-sulfur fuels as well as *fuel cleaning*, stack-gas cleaning, and equipment modifications."[180] As noted in the preamble, fuel cleaning activities are frequently undertaken off-site, by parties not related to the affected EGU. EPA even considered oil desulfurization facilities that would come on-line outside the country after the rule went into effect.[181] Thus, the availability of fuel cleaning technologies, whether or not implemented on site or even directly by the affected source, were part of the basis for the standards of performance.[182]

By 1977, Congress observed that many fossil fuel-fired stationary sources were complying with new source performance standards exclusively by fuel shifting to untreated low-sulfur coal. This made it more expensive for existing sources to use naturally low-sulfur coal (due to supply limitations) and potentially resulted in higher overall SO_2 emissions. To address this, Congress inserted the term "technological" into the definition of standard of performance and required new fossil fuel-fired stationary sources to achieve a percentage reduction in

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[176] *Standards of Performance for New Stationary Sources: Proposed Standards for Five Categories*, 36 Fed. Reg. 15704 (Aug. 17, 1971).
[177] 36 Fed. Reg. 15704, 15704-706.
[178] 36 Fed. Reg. 15704, 15706.
[179] U.S. EPA, Office of Air Programs, *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants*, p. 7 (Aug. 1971).
[180] *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants*, p. 7 (emphasis added). As noted above, fuel cleaning activities are frequently undertaken by parties not related to the affected EGU, off-site.
[181] *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants*, p. 8.
[182] *See Standards of Performance for New Stationary Sources*, 36 Fed. Reg. 24876, 24879 (Dec. 23, 1971).

emissions that would result from burning untreated fuels.[183] Together, this narrowed the underlying considerations used to calculate a standard of performance and would essentially "force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance."[184]

Although Congress strongly discouraged fuel-switching under the 1977 CAA Amendments, Congress made clear that EPA could not require the installation or operation of any particular technological system of continuous reduction under Section 111.[185] Congress nevertheless ensured that EPA could still consider fuel cleaning as part of a "technological system of continuous emission reduction," just as EPA had prior to the 1977 CAA Amendments. To that end, Congress added to the definition of standard of performance for certain new sources in section 111(a)(1) the words "precombustion cleaning or treatment of fuels" to "insure that in upgrading the standards and in defining the 'best technological system of continuous emission reduction', the Administrator would not be limited to consideration of stack gas cleaning or clean combustion processes."[186] Congress also understood that these techniques would not necessarily be accomplished at the individual source. For example, a House committee report indicates that an assessment of the best technological system of continuous emission reduction for fossil fuel-fired power plants would include "various coal-cleaning technologies such as solvent refining, oil desulfurization at the refinery".[187] Coal-cleaning, Senator Muskie observed, can occur at the "minemouth" (rather than at the source), and, similarly, other precombustion fuel treatment processes may or may not even be "undertaken by the source itself."[188] EPA has also recognized in a regulatory analysis of new source performance standards for industrial-commercial-institutional steam generating units that coal-cleaning technology "requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam

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[183] *See* 1977 CAA Amendments, § 109, 91 Stat. at 700; see also, *New Stationary Sources Performance Standards; Electric Utility Steam Generating Units*, 44 Fed. Reg. 33580, 33582 (June 11, 1979).

[184] 44 Fed. Reg. 33580, 33581-33582. In particular, the percentage reduction requirement made burning high-sulfur coals more economical because it would be easier to achieve the reductions than with low-sulfur coals. Achieving a percentage reduction in emissions at the individual plant level could be accomplished in several ways. An individual source could install pollution control technology, such as the application of flue gas desulfurization systems, or receive credit for fuel cleaning or other fuel pre-treatment measures taken "after extraction and prior to combustion". 1977 CAA Amendments, § 109, 91 Stat. at 700. In fact, Congress authorized EPA to give "credit for minemouth and other precombustion fuel treatment processes *whether or not undertaken by the source itself*." Sen. Muskie, Sen. Consideration of H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353 (emphasis added).

[185] 1977 CAA Amendments, § 109, 91 Stat. at 700-01.

[186] Sen. Conf. R. No. 94-1742, at 88 (Sept. 30, 1976).

[187] H.R. Rep. No. 95-294, at 188 (May 12, 1977). If there is any doubt whether coal-cleaning activities must be conducted at a fossil fuel-fired power plant for purposes of identifying the BSER, the committee report also names oil refineries, which are clearly separate facilities.

[188] Sen. Muskie, Sen. Consideration of H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

generating units."[189] Thus, Congress assured that even between 1977 and 1990, standards of performance reflecting the best technological system implementable by an affected source could be based, in part, on technologies operated by third-parties outside the affected source.

In 1990, Congress largely reinstated the 1970 definition of "standard of performance" and thus eliminated many of the restrictions added in the 1977 CAA Amendments, including the specific reference in section 111(a)(1) to fuel cleaning. Nevertheless, there is no indication that reinstating the 1970 definition of standard of performance was designed to limit its scope. Thus, just as fuel cleaning was factored into the first set of regulations for new source performance standards, fuel cleaning is still considered by the EPA in establishing post-1990 CAA Amendment standards. For instance, in 2007, the EPA, in amending its standards of performance for industrial-commercial-institutional steam generating units, required the owner or operator of such units to include "a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A".[190]

All told, the example of fuel cleaning sheds light on the scope of section 111. Since the 1970 CAA Amendments, and up to the present time, the EPA has (with congressional acquiescence) interpreted section 111 to authorize basing standards of performance on off-site fuel cleaning. Even during the period when Congress imposed the most narrow limits on section 111(a)(1) – 1977 to 1990 – Congress expressly authorized standards of performance to be based on off-site fuel cleaning, whether or not undertaken by the source itself.

XVI. CAA Title IV

This section supports section V of the preamble by providing additional information that in Title IV of the Clean Air Act, Congress recognized the integrated nature of the electricity system and the usefulness of dispatch shifts and renewable energy in reducing emissions from coal-fired EGUs. As noted in the preamble, these provisions and the legislative history of Title IV are supportive of interpreting section 111(d) and (a)(1) to be broad enough to include building blocks 2 and 3 because both Title IV and this rulemaking concern the same industry, Title IV was enacted and section 111(a)(1) were revised in the 1990 CAA Amendments, and the Title IV and section 111(a)(1) are linked.

On June 30, 1980, Congress enacted the Acid Precipitation Act of 1980, as part of the broader Energy Security Act, to authorize a ten-year comprehensive study "(1) to identify the causes and effects of acid precipitation and (2) to identify actions to limit or ameliorate the

[189] U.S. EPA, *Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input*, EPA-450/3-86-005, p. 4-4 (June 1986).
[190] 40 C.F.R. § 60.49b(n)(4); see also *Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule*, 72 Fed. Reg. 32742 (June 13, 2007).

harmful effects of acid precipitation."[191] The study, titled the National Acid Precipitation Assessment Program (NAPAP), produced two main reports to Congress: the Interim Assessment, released in September 1987, and the 1990 Integrated Assessment Report, released in November 1991. These reports, including their many drafts, along with many other scientific studies helped shape one of the most significant additions to the CAA in 1990: Title IV.[192]

Leading up to the 1990 CAA Amendments, the NAPAP had established that fossil fuel-fired power plants were the greatest source of acid rain precursors, *i.e.*, sulfur dioxide (SO_2) and nitrogen oxide (NO_x), in the United States and that older plants in particular were responsible for "[m]ore than 90 percent" of total U.S. power plant emissions.[193] However, the existing CAA proved inadequate to address concerns with acid rain because older plants could not be regulated on a national scale for these criteria pollutants due to the pollution exclusions in Section 111(d).[194] Thus, in 1990, Congress added Title IV to address these "principal sources of ... sulfur and nitrogen oxides"[195] and designed it to encourage "energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy ... for reducing air pollution".[196] In doing so, Congress fashioned an SO_2 cap-and-trade program for fossil fuel-fired utilities—the most notable feature of Title IV—and required a technology based NO_x emission rate for certain utility boilers.

Title IV and its legislative history show that Congress was well aware of the unique opportunities for reducing emissions from the utility industry and from existing power plants in particular.[197] In fact, Congress found that many "strategies and technologies for the control of

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[191] Acid Precipitation Act of 1980, Pub. L. 96-294, § 704, 94 Stat. 611, at 770 (June 30, 1980). Under Subtitle B of the Acid Precipitation Act of 1980, Congress instructed the Director of the Office of Science and Technology Policy and the National Academy of Sciences to study the "projected impact on the level of carbon dioxide in the atmosphere, of fossil fuel combustion, coal-conversion and related synthetic fuels activities authorized in the [Energy Security Act]". *Id.* at § 711, 94 Stat. at 774. Congress made clear that the study "should also include an assessment of the economic, physical, climatic, and social effects of such impacts." *Id.*

[192] *See, e.g.*, Sen. Rep. No. 101-228, at 261-346 (Dec. 20, 1989) (discussing Title IV, including NAPAP and other scientific reports).

[193] *See* Sen. Rep. No. 101-228, at 282-83 (Dec. 20, 1989). According to the NAPAP, 23.1 million tons of SO_2 and 20.5 million tons of NO_x were emitted from anthropogenic sources in 1985. *Id.* at 828. Electric utilities accounted for 16.1 million tons of SO_2 and 6.7 million tons of NO_x, and industrial sources (including industrial combustion and industrial processes) accounted for 5.6 million tons of SO_2 and 4.1 million tons of NO_x. *Id.*

[194] Existing plants could be indirectly regulated through the NAAQS program (*e.g.*, by tightening ambient air quality standards) and directly regulated on a case-by-case basis through the EPA's new source review program (*e.g.*, as a result of a plant modification).

[195] 42 U.S.C. § 7651(a)(2); CAA § 401(a)(2).

[196] 42 U.S.C. § 7651(b); CAA § 401(b).

[197] "[B]y their business nature," Congress explained, "utilities appear to be well-suited to create, and to take advantage of, an active market in emissions allowances." Sen. Rep. No. 101-228, at 319 (Dec. 20, 1989). In fact, "utilities already engage in power-pooling arrangements to ensure maximum flexibility and efficiency in supplying power." *Id.* Moreover, the allowance system

precursors to acid deposition exist now that are economically feasible, and improved methods are expected to become increasingly available over the next decade".[198] But by establishing an "allowance system"[199] in lieu of a particular control strategy or technology, Congress intended that the system would encourage such "technologies and strategies" as "energy efficiency; enhanced emissions reduction or control technologies—like sorbent injection, cofiring with natural gas, integrated gasification combined cycles; fuel-switching and least-emissions dispatching in order to maximize emissions reductions."[200] Indeed, the allowance system would "maximize the economic efficiency of the program both to minimize costs and to create incentives for aggressive and innovative efforts to control pollution."[201]

The following briefly addresses the relevant control "strategies and technologies" that are reflected in building blocks 2 and 3.

A. Congressional Support for the Building Block

1. Re-dispatch (Building Block 2)

For Title IV purposes, Congress was aware that "utilities already engage in power-pooling arrangements to ensure maximum flexibility and efficiency in supplying power."[202] Some of these arrangements incorporated least-emissions dispatch for pollution control.[203] Least-emissions dispatch is a "relatively inexpensive approach to air pollution control" and has been considered a pollution control strategy since at least 1968.[204] It has been studied and used specifically to meet SO_2 and NO_x emission limitations and also to meet heat discharge limits.[205]

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enabled parties to "transfer between them and among themselves pursuant to a wide variety of commercial agreements such as under leases, sales agreements and exchanges between emissions and electric power or capacity." *Id.* at 320.

[198] 42 U.S.C. § 7651(a)(4); CAA § 401(a)(4).

[199] *See* Sen. Rep. No. 101-228, at 320 (Dec. 20, 1989).

[200] *See* Sen. Rep. No. 101-228, at 316 (Dec. 20, 1989).

[201] Sen. Rep. No. 101-228, at 320 (Dec. 20, 1989).

[202] Sen. Rep. No. 101-228, at 319 (Dec. 20, 1989).

[203] *See* Sen. Rep. No. 101-228, 316 (Dec. 20, 1989) (recognizing "least-emissions dispatching" as an exploitable technology and strategy used to reduce emissions) and *id.* at 320 (discussing various commercial arrangements including emissions exchanges).

[204] Croke, E.J., et al., "Chicago Air Pollution System Model, Third Quarterly Progress Report," Chicago Department of Air Pollution Control, p. 186 (1968) (discussing the feasibility of "Control by Load Reduction" in combination with load shifting as applied to the Commonwealth Edison Company); see also Shepard, Donald S., *A Load Shifting Model for Air Pollution Control in the Electric Power Industry*, Journal of the Air Pollution Control Association, Vol. 20:11, pp. 756-761 (November 1970).

[205] *See, e.g.*, Delson, Jerome K., *Controlled Emission Dispatch*, IEEE Trans. PAS, Vol. PAS-93, No. 5, pp. 1359-1366 (1974); *see also* Tyle, Navin *et al.*, *Emission Constrained Dispatching of Electric Power*, Paper ICTTE-92-046, Presented at the International Congress on Technology and Technology Exchange (1982), Cadogan, J.B. and L. Eisenberg, *Sulfur Oxide Emission Management for Electric Power Systems*, IEEE Trans. PAS, Vol. PAS-96, No. 2, pp. 393-400

It was therefore logical to design an allowance system that took these arrangements into account.[206] In fact, the Senate Report explained that "the Administrator should be mindful that to exploit the efficiencies afforded by the allowance system," recognizing that parties would transfer allowances "between them and among themselves pursuant to a wide variety of commercial arrangements such as under leases, sales agreements and exchanges between emissions and electric power or capacity."[207]

2. Renewables (Building Block 3)

To encourage the "use of renewable and clean alternative technologies," Congress added Section 404(g) to establish "a renewable energy technology reserve within the allowance system."[208] The addition would encourage utilities to adopt renewable energy technologies, which, "along with increased energy efficiency, can greatly reduce emissions of acid rain precursors and global warming gases."[209] "That makes them a potent weapon against catastrophic climate change, widespread respiratory disease, crop and forest damage, and the poisoning of our lakes and streams."[210] "With a little foresight," Senator Fowler explained, "we can also see that renewable systems can easily and cost-effectively be integrated into the existing utility sector, increasing power supplies without increasing pollution."[211]

Allowances for emissions avoided through energy conservation and renewable energy would be allocated on a first-come-first-served basis from the reserve pursuant to Section 404(f). Such allowances would be issued to an electric utility for qualified energy conservation measures or qualified renewable energy paid for "directly or through purchase from another person,"[212] such as "a third-party provider."[213] By adding Section 404(f), Congress recognized that

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(1977); and Friedmann, Paul G., *Power Dispatch Strategies for Emission and Environmental Control*, Proc. ISA Power Institute Symp., Vol. 16 (1973).

[206] *See* McDermott, K.A. and D.W. South, Argonne National Laboratory, Alternative Emission Cost Control Strategies for Electric Utilities: A Review, pp. 18-22 (Dec. 1990) (work sponsored by U.S. Department of Energy) (reproducing section 7 (*Electric Utilities: Alternative Emission Cost Control Strategies*) of South, D.W., *et al.*, *Technologies and Other Measures for Controlling Emissions: Performance, Cost and Applicability*, which is NAPAP Rep. SOS/T 25, in Vol. IV of *Acidic Deposition: State of Science/Technology* (Dec. 1990)) (finding that "a least emission dispatch program can be used in conjunction with ... trading programs." The report also stated that "[e]nvironmental dispatching appears to be a viable strategy when used selectively and in tandem with other emission reductions strategies, such as fuel switching, conservation (demand-side management) or scrubber installations.").

[207] Sen. Rep. No. 101-228, at 320 (Dec. 20, 1989).

[208] Sen. Fowler, Sen. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7103.

[209] Sen. Fowler, Sen. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.

[210] Sen. Fowler, Sen. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.

[211] Sen. Fowler, Sen. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.

[212] 42 U.S.C. § 7651c(f)(2)(B); CAA § 404(f)(2)(B).

[213] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 675 (May 17, 1990).

> [c]onservation and renewables not only significantly curtail sulfur dioxide emissions, but they emit little or no nitrogen oxides and carbon dioxide, and decrease the envionmental [*sic*] degradation of land and water associated with oil imports and energy production.[214]

Moreover, "[t]hese important environmental attributes should make conservation and renewables a central part of the nation's clean air policies immediately."[215]

B. Title IV Does Not Preclude Consideration of the Building Blocks as the BSER

These Title IV provisions and the accompanying statements in the legislative history make clear that Congress considered the tools proposed under buildings blocks 2 and 3 as appropriate and cost-effective methods to reducing emissions of SO_2 and NO_x from fossil fuel-fired power plants. Congress was also clear that these tools could be used "in combination" and in many cases could be used to reduce emissions of CO_2. Accordingly, these measures are appropriately within the scope of Section 111(a)(1) and may be considered as the BSER.

Some commenters claim that Title IV precludes regulation of the "electricity system as a whole" and that Sections 401(b) and 404(f) in particular prohibit EPA from considering building blocks 2 and 3 as the BSER. As an initial matter, this rule does not regulate the "electricity system as a whole." All this rule provides is an emission guideline to assist States in establishing standards of performance for existing fossil fuel-fired power plants. The fact that power plants may serve an interstate electricity system does not mean that these same plants cannot be regulated under Section 111.[216] Nor does regulating these same plants under Section 111 mean that EPA is regulating the electricity system as a whole.

Second, neither the purpose statements in Section 401(b) nor the crediting instructions in Section 404(f) preclude consideration of building blocks 2 and 3 under Section 111. These provisions simply confirm that Congress designed Title IV to "encourage" renewable energy technologies. Section 404(f) in particular provides additional incentives to credit sources for compliance with Title IV. Nothing in the text of Title IV nor in its legislative history suggests that these provisions were intended to preclude the consideration of certain "strategies and technologies" elsewhere under the CAA. Indeed, these provisions highlight Congress' preferences for cleaner and cost-effective measures to "reduce emissions of acid rain precursors

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[214] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 674 (May 17, 1990).

[215] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 674 (May 17, 1990).

[216] In fact, "steam electric powerplants" were expressly identified as one of 19 source categories "for which the Congress would expect standards of performance to be established" under section 111. *See* "Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970 (Exhibit 1), Sen. Consideration of H.R. Rep. No. 91-1783 (Dec. 18, 1970), 1970 CAA Legis. Hist. at 133.

and global warming gases."[217] In fact, there is strong legislative history indicating that "conservation and renewables" were intended to become "a central part of the nation's clean air policies immediately."[218]

XVII. Renewable Energy in SIPs

This section supports the determination in section V that building block 3 is an adequately demonstrated component of the BSER, by identifying additional examples in which the States and the EPA have relied or are developing plans to rely, in CAA section 110 state implementation plans (SIPs), on renewable energy (RE) for emission reductions. It should be noted that not all of these SIP measures have been or may be limited to actions taken by fossil fuel-fired power plants themselves; some of these actions have been, or may be, government actions such as the governmental purchase of renewable energy certificates (RECs). These examples of governmental action are useful because they illustrate some of the types of non-BSER actions that are available for a state to meet its section 111(d) requirements. It should also be noted that while this section focuses on RE, it also makes occasional reference to demand-side energy efficiency (EE) projects in SIPs as well.

As the EPA noted in the proposal, SIPs already include RE measures to reduce the need for generation from the more polluting forms of energy generation, such as fossil fuel-fired EGUs. *See* 79 FR at 34887-88. As the EPA noted, several states have already adopted RE measures in their SIPs for attaining and maintaining the national ambient air quality standards (NAAQS), and the EPA has provided initial guidance for states to do so.[219] For example, in 2005, EPA approved inclusion of county government commitments to purchase 5 percent of their annual electricity consumption from wind power in Maryland's SIP.[220] In 2007, Virginia, Maryland, and the District of Columbia submitted SIP revisions for the 1997 8-hr ozone in the Washington non-attainment area that included commitments by municipalities to purchase renewable energy certificates representing 123 million kWh of wind energy each year from 2004 to 2009.[221] Similarly, Connecticut's 1997 8-hour ozone NAAQS SIP submittal Connecticut included solar photovoltaic installations.[222]

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[217] Sen. Fowler, Sen. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.
[218] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 674 (May 17, 1990).
[219] *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf;* Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf*
[220] 70 Fed. Reg. 24,988 (May 12, 2005).
[221] *Id.* at K-9.
[222] CT 1997 8-hour ozone SIP Web site, *http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619* (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

Since those SIPs were submitted, many states have adopted legislative mandates for renewable energy, and the EPA has provided additional guidance for including EE/RE projects in SIPs, which we refer to as the EE/RE Roadmap.[223] The EPA has also partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including EE/RE in a NAAQS SIP and to provide real-world examples and lessons learned through those states' case studies.[224]

In the EE/RE Roadmap, EPA recognized four "pathways" for incorporating EE and RE into SIPs: the baseline emissions projection pathway, the control strategy pathway, the emerging/voluntary measures pathway, and the weight of evidence pathway. Of these four options, only the "control strategy" pathway results in federally enforceable obligations with respect to EE and RE. A collection of fifteen States provided additional information to EPA noting some states may choose the federally-enforceable control strategy pathway within their State Plans, and "EPA and the state would share enforcement authority."[225] However, these States anticipated that most states would choose the "baseline emissions projection pathway" in which states would project the emissions reduction attributable to those programs over the course of the compliance period, to demonstrate that such programs "substantially limit section 111(d) source emissions."[226] These states went on to provide detailed appendices for twelve states explaining the success of their various investments in EE and RE strategies for pollution control.[227]

Multiple commenters on the CPP responded to EPA's request for comment on these issues and many, including states, strongly affirmed that the use of RE and EE in SIPs is now an accepted and growing practice. These commenters also provided greater detail on the various options states have for treating RE and EE in their SIPs, and urged EPA to encourage states to use its existing guidance on RE and EE, particularly EPA's 2012 EE/RE Roadmap, in developing plans under the CPP.[228]

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[223] U.S. EPA, Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs (July 2012), *http://epa.gov/airquality/eere/manual.html* (hereinafter "EE/RE Roadmap")
[224] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013), *http://www.nescaum.org/documents/nescaum-final-reptto-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf*.
[225] States' Roadmap, at 32.
[226] *Id.*
[227] *Id.* at 34-57.
[228] *See* Alliance to Save Energy, Comments on the Clean Power Plan, at 10 (Nov. 24, 2014) (hereinafter "Alliance Comments") ("We urge EPA to emphasize the applicability of [the RE/EE Roadmap and other resources] and to provide pertinent training and technical assistance to facilitate inclusion of EE in state CPP compliance."); States' Roadmap on Reducing Carbon Pollution, Attach. at 20 (Dec. 16, 2014) (hereinafter "States' Roadmap") ("The [2012] Roadmap discusses all three of our strategies, including energy efficiency programs, emissions trading

EPA has continued to work closely with states engaged in pioneering efforts to reduce power plant pollution through RE measures. For example, EPA has collaborated with the Connecticut Department of Environmental Protection (CTDEP) to develop pathways for the state to use its renewable portfolio standard (RPS) requirements and extensive energy efficiency programs for CAA planning and compliance under section 110.[229] Having assessed the effect of its EE and RE projects on NO_X emissions during high demand days as part of the weight of evidence analysis in its 2007 8-hr ozone attainment demonstration, CTDEP contacted EPA Region 1 for guidance on additional opportunities for incorporating RE and EE programs into its CAA planning.[230] Region 1 responded by providing CTDEP with a guidance letter outlining key issues and questions for CTDEP to consider in incorporating RE/EE measures into its SIP as federally enforceable control measures, in particular, discussing the four key criteria: permanent, enforceable, quantifiable, and surplus.[231]

Commenters on the proposal have also noted that recently developed tools – particularly, EPA's AVERT system[232] -- facilitate the calculation of the amount of emission reductions available from RE, as well as EE. AVERT relies on publicly available and auditable data maintained by EPA to estimate the emission benefits of RE and EE policies and programs, including reductions in carbon dioxide. States, PUCs, analysts, and environmental agencies are currently using AVERT to lower the costs of their analytical work, ensure and improve electric supply reliability, and diversify their energy supply portfolios.[233] Commenters have noted that AVERT, along with EPA's new guidance materials, will significantly ease the quantification and documentation issues with RE, as well as EE.[234]

XVIII. EPA Transport Rulemakings and the Building Blocks

This section supports the preamble section V discussion concerning the integrated nature of the electricity sector and the determinations that building blocks 2 and 3 are adequately demonstrated by pointing out similar statements and conclusions that the EPA made in the transport rulemakings, the NOx SIP Call, Clean Air Interstate Rule (CAIR), and Cross-State Air Pollution Rule (CSAPR).

The EPA's regulatory initiatives under the CAA's "good neighbor" provision in section 110(a)(2)(D)(i)(I) have recognized the unique opportunities available for reducing emission from

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systems, and renewable portfolio standards which can help reduce grid-level emissions. Those same strategies work to reduce greenhouse gas pollution as well.").

[229] EE/RE Roadmap, Appendix K, at K-9-K-10, K-12-14.

[230] *Id.*

[231] *Id.* at K-14-K-15, K-32-K-38.

[232] See "Avoided Emissions and geneRation Tool (AVERT)," http://epa.gov/avert/ (last updated May 21, 2015).

[233] AVERT, Fact Sheet for Decision Makers, available at http://www.epa.gov/statelocalclimate/documents/pdf/AVERT%20Decision%20Makers%20Fact%20Sheet%202-13-14%20Final_508.pdf

[234] *See* Alliance Comments, at 10 ("AVERT, though it has some limitations, is an easy-to-use tool that can provide adequate calculations of avoided emissions.").

fossil fuel-fired EGUs. The EPA's NO_x SIP Call, CAIR, and CSAPR have recognized that emissions from EGUs can be reduced through many of the building-block mechanisms identified as part of the BSER in this rule, as well as from demand-side energy efficiency. Commenters noted these salient precedents as well.[235]

A. Building Block 2 – Generation Shifts Among Affected EGUs

1. NO_x SIP Call

In the NO_x SIP Call, the EPA calculated the state emission budgets in part based on the degree of emission reductions that could be achieved from EGUs by applying feasible and highly cost-effective controls.[236] The EPA determined that one set of highly cost-effective controls for EGUs was an intrastate program that allowed EGUs to meet an average emission rate of 0.15 lbs/mmBtu.[237] The EPA explained that it had determined that these controls were highly-cost effective because, "*considering changes in dispatch* and other aspects of the future of the nation's power system," the projected average costs were $1,499 per ton.[238] This mirrored EPA's approach at the proposal stage, during which the EPA also clearly considered generation shifting to be a legitimate way to reduce NO_x emissions from EGUs:

> System NO_x emissions can be reduced in several ways. *One way is through dispatch decisions, by increasing generation from lower-emitting units, while decreasing the use of higher-NO_x units*. For States covered by the Ozone Transport Rulemaking, the model results did indicate lower levels of generation from fossil-fueled units under the proposed regulatory approach.[239]

2. CAIR

In CAIR, the EPA noted the importance of regulating EGUs in a holistic manner that takes into account the generation shifting facilitated by the interconnected nature of the electricity grid, and the fact that all EGUs produce an identical product—electricity. Several of EPA's decisions regarding CAIR were influenced by the practical reality of generation shifting in the utility power sector.

In some instances, the EPA recognized that because shifting generation also shifts emissions in way that could interfere with CAIR's air quality goals, it was important that any regulation of EGUs under CAIR apply to all EGUs. For example, the prospect of generation shifting led the EPA to reject commenters' suggestion to exclude all cogeneration units from CAIR's model cap-and-trade program.[240] Instead, the EPA found it "important to include in the

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[235] *See, e.g.*, Comments of Environmental Defense Fund, Docket ID No. EPA-HQ-OAR-2013-0602-23140 at 21–23.
[236] 63 FR at 57362.
[237] 63 FR at 57401.
[238] 63 FR at 57401 (emphasis added).
[239] NO_x SIP Call Proposal RIA at 2-16 (emphasis added).
[240] 70 FR 25162, 25277 (May 12, 2005).

CAIR Program all units, including cogeneration units, substantially in the business of selling electricity," because:

> Inclusion of all units substantially in the electricity sales business minimizes the potential for shifting utilization, and emissions, from regulated to unregulated units in that business and thereby freeing up allowances, with the result that total emissions from generation of electricity for sale exceed the CAIR emissions caps. *The fact that units in the electricity sales business are generally interconnected through their access to the grid significantly increases the potential for utilization shifting.*[241]

The EPA's requirements for state transport SIPs submitted under CAIR were similarly influenced by the prospect that generation shifting among EGUs could undermine CAIR's air quality goals. The EPA explained that if a state wished to meet is good neighbor obligation under CAIR by limiting emissions from EGUs, it would have to impose limits on *all* EGUs:

> The requirement to cap all EGUs is important because it prevents shifting of utilization (and resulting emissions) to uncapped EGUs. *The EGUs are part of a highly interconnected electricity grid that makes utilization shifting likely and even common*. The units are large and offer the same market product (*i.e.*, electricity), and therefore the units that are least expensive to operate are likely to be operated as much as possible. If capped and uncapped units are interconnected, the uncapped units' costs would tend to decrease relative to the capped units, which must either reduce emissions or use or buy allowances, and the uncapped units' utilization would likely increase. The cap ensures that emissions reductions from these interconnected sources are actually achieved rather than emissions simply shifting among sources. The caps constitute the State EGU Budgets for SO_2 and NO_x.[242]

The potentially negative consequence of generation shifting between regulated and unregulated EGUs drove the EPA's decisions to include certain cogeneration units in the CAIR model trading program, and to require that any state regulation of EGUs under CAIR apply to all EGUs. Similarly, the decision whether EGUs built on Tribal lands would have to be included in an EGU cap-and-trade program turned on the potential for generation shifting across an interconnected electricity grid:

> ... in the event of any future planned construction of EGUs on Tribal lands within the CAIR region, EPA intends to work with the relevant Tribal government to regulate the EGU through either a Tribal implementation plan (TIP) or a Federal implementation plan (FIP). We anticipate that at a minimum, a proposed EGU on a reservation within a State participating in the CAIR cap and trade program would need to be made subject to the cap and trade program. In the case of a new EGU on a reservation in a CAIR-affected State which chose not to participate in the cap and trade program, the new EGU might also be required, through a TIP or FIP, to

[241] 70 FR at 25277 (emphasis added);
[242] 70 FR at 25256–57 (emphasis added).

> participate in the program. *This would depend on the potential for emissions shifting and other specific circumstances (e.g., whether the EGU would service the electric grid of States involved in the cap and trade program.)*[243]

The EPA was not only motivated in CAIR to develop a rule that would avoid the negative consequences of generation shifting between regulated and unregulated EGUs. The Agency was also influenced by the opportunities that generation shifting presented as a compliance option. For example, the EPA considered whether certain EGUs smaller than 250 MW should be included in the CAIR budgets and model rule, given commenters' claims that inclusion in CAIR would cause these smaller EGUs to shut down.[244] The EPA declined to set a cut-off at 250 MW, noting its projections that "some [EGUs] below 250 MW" would implement highly cost-effective controls, and that smaller EGUs "also have the option to ... *alter dispatch, and/or purchase power*" as a means of compliance.[245]

3. CSAPR

In evaluating the costs for CSAPR, the EPA projected that fossil-fuel-fired EGUs would achieve emission reductions through, *inter alia*, "increased dispatch of more efficient units and lower-emitting generation technologies (e.g., some reduction of coal-fired generation with an increase of generation from natural gas)."[246]

The EPA established the stringency of CSAPR's deadlines based on the fact that EGUs were expected to engage in generation shifting. For example, in quantifying the state budgets for CSAPR, the EPA assessed the emission reductions that EGUs could achieve at various cost thresholds. The ability of EGUs to engage in generation shifting directly influenced the stringency of state budgets. For example, the EPA based 2012 requirements for "Group 1" states on the emission reductions emissions that EGUs were expected to achieve by implementing controls that cost up to $500/ton. The EPA decided that a certain quantity of emission reductions was "feasible" at that cost threshold because affected EGUs could cheaply and efficiently reduce emissions by generation shifting to lower-emitting sources:

> EPA applied escalating SO_2 cost per ton thresholds for Group 1 states to create the cost curves for 2014 and beyond. For 2012 SO_2, the cost per ton was held constant at $500/ton as the cost thresholds in 2014 and beyond were varied. The advanced pollution controls incentivized by these higher cost-per-ton levels can reasonably be installed by 2014. EPA also considered whether any of these emission reductions could be achieved prior to 2014. For the reasons that follow, EPA concluded that significant reductions could be achieved by 2012 and that it is important to require

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[243] 70 FR at 25168 (emphasis added).
[244] 70 FR at 25276.
[245] 70 FR at 25276; U.S. EPA, *Corrected Response to Significant Public Comments on the Proposed Clean Air Interstate Rule*, Docket No. OAR-2003-0053-2172 at 158–59 (April 2005) (emphasis added).
[246] Regulatory Impact Analysis (RIA) for the Final Transport Rule, Docket ID No. EPA-HQ-OAR-2009-0491 at 255–56 (June 2011), *available at* http://www.epa.gov/airtransport/pdfs/FinalRIA.pdf.

> all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable. *SO_2 and NO_x reductions come from* operating existing controls, installing combustion controls, fuel switching, and *increased dispatch of lower-emitting generation which can be achieved by 2012. In general, compliance mechanisms that do not involve post-combustion control installation are feasible before 2014. For this reason, EPA believes it is appropriate to require these emissions to be removed in 2012*, consistent with the Act's requirement that downwind states attain the NAAQS as expeditiously as practicable.
>
> Therefore, all of the cost curves presented below include all feasible 2012 reductions up to a threshold of $ 500/ton for SO_2 and $ 500/ton for annual NO_x in states linked to receptors for $PM_{2.5}$, as well as $ 500/ton for ozone-season NO_x in states linked to receptors for ozone. *These cost per ton levels do not precipitate advanced post-combustion control installation in 2012* (as EPA acknowledges that such installations are not feasible by 2012), *but they do promote the compliance options outlined above*.[247]

EPA's selection of a $500 threshold "reflect[ed] an amount of ... generation shifting that can be achieved for $500/ton."[248] Had EPA ignored the reality of generation shifting when determining the CSAPR requirements, the 2012 budgets EPA set based on feasibility would have been less stringent than they ended up being.

It made sense for EPA to take generation shifting into account when setting the CSAPR budgets because, at all compliance stages, EPA projected that generation shifting was a technique that EGUs would actually engage in as a means of reducing emissions: The electric utility sector would meet 2012 NO_x requirements by, *inter alia*, "dispatching lower emitting units more often ...."[249] For the 2012 SO_2 requirements, EPA projected that, "the fleet will increase dispatch from lower-sulfur-emitting units as well as from natural gas-fired generators."[250] For the 2014 phase 2 compliance deadline, EPA projected that sector would reduce SO_2 by "dispatch[ing] lower emitting generation units."[251] [252]

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[247] 76 FR at 48252 (emphasis added).
[248] 76 FR at 48280.
[249] 76 FR at 48279.
[250] 76 FR at 48279; *see also id.* at 48280 (describing EPA's modeling showing that for SO_2, EGUs would use "changes in dispatch and generation shifting from higher emitting units to lower emitting units" as a means of meeting requirements).
[251] 76 FR at 48281.
[252] Another example of generation shifting to control emissions can be found in a recent compliance agreement between the EPA and TVA to resolve NSR issues. There, the EPA gave TVA a few extra months to achieve continuous operation of its FGDs at the Kingston plant, while it worked out some issues with the associated gypsum disposal ponds. During that period, TVA was required to dispatch the fully controlled, but more costly to run, Bull Run unit before it could operate any of the Kingston units without FGD. TVA Federal Facilities Compliance

B. Building Block 3 – Renewable Energy

The following describes the role that RE played in the transport rules, and also mentions the roles that energy efficiency, both supply side (building block 1) and demand-side (building block 4) played in those rules. While the EPA relied on other measures as the basis for the control requirements, it recognized that RE could be used for compliance and encouraged that use.

1. NO_x SIP Call

In the NO_x SIP Call, the EPA noted that NO_X emissions from EGUs could be reduced through efficiency projects that improve EGU heat rate (referred to in the instant rule as building block 1), and by replacing generation at existing EGUs with generation from renewable energy projects (building block 3).[253] The EPA also noted that demand-side EE programs can reduce emissions from EGUs. The NO_x SIP Call's emission budgets were ultimately based on "highly cost-effective measures" that did not include these methods of reducing EGU emissions.[254] However, the EPA recognized that heat rate improvement, renewable energy, and demand-side EE programs could be part of a "cost-effective NO_X reduction strategy" for EGUs, including as part of an emission trading program:

> The EPA believes that, with respect to EGUs, there is a large potential for energy efficiency and renewables in the NO_x SIP call region that reduce demand and provide for more environmentally-friendly energy resources. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_x emissions proportionately, while the associated generator would produce the same amount of electricity. Renewable energy source generation includes hydroelectric, solar, wind, and geothermal generation. EPA recognizes that promotion of energy efficiency and renewables can contribute to a cost-effective NO_x reduction strategy. As such, EPA encourages States in the NO_x SIP call region to consider including energy efficiency and renewables as a strategy in meeting their NO_x budgets. One way to achieve this goal is by including a provision within a State's NO_x Budget Trading Rule that allocates a portion of a State's trading program budget to implementers of energy efficiency and renewables projects that reduce energy-related NO_x emissions during the ozone season. Another is to include energy efficiency and renewables projects as part of a State's implementation plan.[255]

Agreement, http://www2.epa.gov/enforcement/tva-federal-facilities-compliance-agreement-matter-tennessee-valley-authority-docket-no.

[253] 63 FR 57356, 57359, 57438 (Oct. 27, 1998).

[254] *See, e.g.*, 63 FR at 57405.

[255] 63 FR at 57438.

The EPA's treatment in the NO_x SIP Call of heat rate improvements, renewable energy projects, and demand-side energy efficiency as "additional control measures" for reducing emissions from EGUs further illustrates how the EPA has encouraged sources and states to leverage the integration of the utility power sector to reduce emissions.[256] Indeed, when some commenters expressed concern that the NO_x SIP Call provided insufficient time for the construction, procurement, and installation of add-on pollution controls at EGUs, the EPA allayed those concerns in part by pointing to the "NO_x-reducing benefits that energy efficiency and renewables projects provide, many of which could be developed in less than three years and incorporated into a SIP."[257] With respect to cost, the EPA noted that for many states, "energy efficiency and renewable energy actions may be the least cost method of compliance with the requirements of the SIP Call," and opened the door for states to award emission trading allowances for energy efficiency and renewable energy projects.[258]

In that vein, the EPA established a NO_x Budget Trading Program to facilitate states' implementation of an interstate trading program, and included an option for states to set-aside allowances for renewable energy and energy efficiency projects.[259] The EPA explained that "the Clean Air Act Amendments of 1990 and the Pollution Prevention Act (PPA) of 1990 recognize the significant role that energy efficiency and renewable energy resources can play in reducing pollution and achieving the nation's environmental goals."[260] These set-aside pools of allowances are for "energy efficiency and renewable energy projects that reduce electricity generation," and thereby "reduce emissions of pollutants, including NO_x."[261] The EPA's Climate Protection Division explained in guidance for the set-asides that this voluntary option for states "focuses primarily on end-use electricity efficiency and renewable energy actions, since the amount and source of electricity consumed by end-users affects the quantity of NO_x emitted at an electricity generating unit (EGU)."[262] By 2005, seven states had incorporated such energy efficiency and/or renewable energy programs into their NO_x Trading Program budgets,[263]

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[256] *See* 63 FR at 57438 (discussing these measures as distinct from control measures for reducing emissions from non-EGU stationary sources, or from mobile sources).
[257] 63 FR at 57449.
[258] U.S. EPA, *Responses to Significant Comments on the Proposed Finding of Significant Contribution & Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone*, Docket No. A-96-56 VI-C-1 at 332–33 (Sept. 24, 1998).
[259] *See* U.S. EPA, *Guidance on Establishing an Energy Efficiency and Renewable Energy (EE/RE) Set-Aside in the NO_x Budget Trading Program*, vol. 1 (March 1999); *id.* vol. 2 (April 2000); *id.* vol. 3 (July 2007).
[260] U.S. EPA Climate Prot. Div., *Guidance on Establishing an Energy Efficiency and Renewable Energy (EE/RE) Set-Aside in the NO_x Budget Trading Program*, vol. 3 at ii (July 2007) (citing as an example the Clean Air Act's "encouragement of energy conservation and renewable energy resources in the Acid Rain Program").
[261] *Id.*
[262] *Id.*
[263] *Id.* at 1-5.

reflecting the reality that "[e]nergy efficiency and renewable energy resources can result in reductions of fossil-fuel energy use, which are a primary cause of pollution emissions."[264]

2. CAIR

As some commenters noted, CAIR continued in the tradition of the NO_x SIP Call by allowing the use of allowance set-asides for renewables and energy efficiency.[265] The EPA explained that in allocating allowances, "States are welcome to use set-asides" to "promot[e] energy efficiency or renewables."[266] The EPA also promulgated an example method for allocating allowances based in part on electrical output, and noted that "states may choose to include non-emitting generation (such as renewables)" within that type of approach.[267]

3. CSAPR

When EPA promulgated CSAPR as a replacement for CAIR, much of the prior rule's treatment of renewables and energy efficiency carried over. For example, EPA took comment on two mechanisms for states to submit SIPs that would satisfy CSAPR, both of which allowed the state to allocate allowances to "renewable energy facilities."[268]

XIV. Stack Height Emissions Balancing Policy, BB-2, and the Integrated Electricity Sector

This section supports section V of the preamble by describing how the 1988 Stack Height Emissions Balancing Policy recognized the integrated electricity sector and the usefulness of shifting dispatch to lower emitting sources as a means of emissions reduction.

In 1988, the EPA issued the Stack Height Emissions Balancing Policy,[269] which implemented the revised stack height regulation, issued under CAA section 123, on July 8, 1985. This 1988 policy addresses the special case of "lower emissions dispatch," which explicitly couples the curtailment of operations at high-emitting EGUs with increased use of well-controlled EGUs to assure overall emission reductions, and authorizes its use where specified criteria are met.[270]

In 1977, Congress added CAA section 123 in order to address the use of "dispersion techniques," such as unnecessarily tall smokestacks, as a method of obtaining less stringent

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[264] *Id.* at i.
[265] *See, e.g.*, 70 FR 25162, 25279 (May 12, 2005).
[266] U.S. Envtl. Prot. Agency, *Corrected Response to Significant Public Comments on the Proposed Clean Air Interstate Rule*, Docket No. OAR-2003-0053-2172 at 797 (April 2005).
[267] *Id.* at 114; 70 FR at 25280.
[268] 76 FR 48208, 48326–28 (Aug. 8, 2011) ("the state may allocate allowances to ... renewable energy facilities").
[269] 53 FR 480 (Jan. 7, 1988).
[270] 53 FR at 480, "Detailed Response to Public Comments on the December 23, 1985 Proposal," pp. 2-3.

emission limitations.[271] Dispersion techniques are techniques that lower the predicted ground-level concentrations of a pollutant,[272] for example by using excessively tall stacks that exceed "good engineering practice" (GEP), or varying emissions based on weather conditions.[273] Congress saw these attempts to obtain less stringent emission limitations by diluting emissions as antithetical to the pollution-reducing goals of the CAA.[274] In order to eliminate the incentive to use dispersion techniques, section 123 provides that the "degree of emission limitation required" from a source may "not be affected in any manner" by that source's use of dispersion techniques.[275] Thus, for example, sources with unnecessarily tall stacks that dispersed pollutants would be treated for standard-setting purposes as if those stacks "were note excessively 'tall.'"[276]

Congress understood that the costs of complying with these more stringent limits could be high, and accordingly grandfathered-in some older sources with tall stacks.[277] For the other sources with unnecessarily tall stacks, or that had been using other dispersion techniques, section 123 and EPA's implementing regulations meant that they would have to comply with more stringent (and costly) emission limitations.[278]

In order to ameliorate cost concerns for tall-stacked sources, EPA in 1988 promulgated a "Stack Heights Emission Balancing Policy."[279] That policy allowed these sources "to meet more stringent emission limitations required by the revised stack height regulation by securing emission limitations from another source or sources ...."[280]

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[271] For example, if a source built a tall enough smokestack in a nonattainment area, the pollutants would be diluted in the atmosphere and not contribute as much (if at all) to monitors in the area. Section 123 was intended to eliminate this incentive to use unnecessarily tall stacks, which Congress saw as an improper "attempt to use dispersion rather than clean up." S. Rep. No-94-1742 (accompanying S. 3219), as found in 5 Legislative History of Clean Air Act Amendments of 1977 at 4435.
[272] 50 Fed. Reg. 52418, 52418 (Dec. 23, 1985).
[273] *See* 40 C.F.R. § 51.100(hh)(1).
[274] *See, e.g.*, S. Rep. No-94-1742 (accompanying S. 3219), as found in 5 Legislative History of Clean Air Act Amendments of 1977 at 4435 (calling these techniques improper "attempt to use dispersion rather than clean up").
[275] 42 U.S.C. § 7423(a)(1).
[276] 53 Fed. Reg. at 481; 50 Fed. Reg. 27,892. For example, if a source's 100-meter stack exceed good engineering practices by 35 meters, that source would be treated for emission modeling and standard-setting purposes as if its stack was only 65-meters tall. Under the legal fiction of that shorter stack, the source's emissions would have a more significant effect on the ambient air, and the source would likely be subject to more stringent emission limitations.
[277] *See* 42 U.S.C. § 7423(a) (grandfathering in "stack heights in existence before December 31, 1970").
[278] *See* 50 Fed. Reg. 52418, 52418 (Dec. 23, 1985).
[279] 53 Fed. Reg. 480 (Jan. 7, 1988).
[280] 53 Fed. Reg. 480, 481 (Jan. 7, 1988). The crediting sources are required to be in the same state or air quality control region as the affected source, and offsetting reductions must be in a 1:1.2 ratio in order to ensure environmental benefits are achieved. *Id.*

In evaluating how to apply the Emission Balancing Policy, EPA recognized that the integrated nature of the electricity system provided unique opportunities for EGUs affected by stack height rules to reduce their emissions through "lower emission dispatch":

> "Lower emissions dispatch" is the term used in this policy to describe a utility company, holding company, or powerpool management strategy to control emissions by *decreasing electricity production at higher emitting* (e.g., higher lbs/10^6 Btu) *power plants*, and *increasing electricity production at lower emitting (cleaner) power plants*, rather than distributing (dispatching) electricity production solely on the basis of least cost.[281]

Provided that sources could show "enforceable, easily monitored procedures for assuring equivalent emission reductions," EPA committed itself to reviewing proposals to reduce EGU emissions through lower emission dispatch on a case-by-case basis.[282] EPA further recognized, however, that the integrated nature of the electricity grid required a system-wide approach to ensuring that emission reductions achieved from some EGUs were not obviated by increased emissions from others:

> EPA believes that the potential for shifting production demand (e.g., increased dispatching) to less well-controlled sources as a result of an emissions balance could generally be offset by use of such practices as an enforceable system of production constraints (i.e., caps and floors) and emission limits selected. However, in the case of lower emission dispatch (LED), methods by which emission reductions are calculated and enforced may have to be expanded to include consideration of changes in capacity factors for all sources in a system affected by the proposed LED approach.[283]

XV. Emissions Trading

This section supports section V of the preamble by describing EPA rules, primarily for the electric power sector, that rely on emissions trading.

As discussed in section V., EPA has promulgated numerous rules, under the authority of several CAA provisions, that base emission reduction obligations on the ability of sources to engage in emissions trading and purchase emission reduction credits from other sources. In purchasing emission reduction credits to achieve an emission limit – which, in the present rule, is one of the measures to implement building blocks 2 and 3 – the source must engage with other entities to achieve its emission limit. In the case of emissions trading, the source typically does not itself implement measures within its facility to control its emissions, but instead depends on

[281] 53 Fed. Reg. 480, 482 (Jan. 7, 1988) (emphasis added).
[282] 53 Fed. Reg. 480, 482 (Jan. 7, 1988).
[283] "Detailed Response to Public Comments on the December 23, 1985 Proposal," Docket No. A-85-05 at 2–3 (accompanying 53 Fed. Reg. 480 (Jan. 7, 1988)).

other entities to sell it allowances or emission reduction credits, which the other entities typically are able to sell because they have controlled their own emissions.

A. Clean Air Mercury Rule

The EPA's 2005 Clean Air Mercury Rule[284] was "a nationwide interstate cap-and-trade program for mercury, with mercury allowances fully allocated at the level authorized by the Administrator and with full and unrestricted participation by affected sources in all 50 states."[285] By establishing a cap-and-trade program for mercury, EPA projected that mercury reductions would "result from units that are most cost effective to control, which enables those units that are not cost effective to use other approaches for compliance including buying allowances, switching fuels, or making dispatch changes."[286] This program enabled EPA to set the cap's stringency at a level commensurate with widespread compliance (whereas if the cap were based solely on the installation of control technologies, the cap would not be cost-effective for the source category).

In CAMR, the EPA determined the BSER to be the cap-and-trade program:

> EPA must next ''determine'' that such a system is ''the best system of emissions reductions which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) * * * has been adequately demonstrated.'' (See CAA section 111(a)(1).) EPA has determined that a cap-and-trade program based on control technology available in the relevant timeframe is the best system for reducing Hg emissions from existing coal-fired Utility Units.[287]

The EPA justified this determination by reviewing the successful cap-and-trade programs for EGUs in Title IV and the 1998 NOx SIP Call, and concluded:

> The success of the Acid Rain cap-and trade program for utility SO2 emissions, which EPA duplicated in large measure with the NOX SIP Call cap-and-trade program for, primarily, utility NO_x emission[s] from utilities qualifies as the "best system of emission reductions" that "has been adequately demonstrated."[288]

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[284] 70 Fed. Reg. 28606 (May 18, 2005). CAMR was vacated by the D.C. Circuit on account of the EPA's flawed CAA section 112 delisting rule, although the court declined to reach the merits of the EPA's interpretation of CAA section 111(d). *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).
[285] Comments of the Utility Air Resources Group on the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units and Supplemental Notice, 133 (June 29, 2004).
[286] 70 Fed. Reg. 28606, 28619 (May 18, 2005).
[287] 70 FR at 28617.
[288] 70 FR at 28617.

That interpretation was recognized by industry commenters as "reasonable,"[289] indeed, "compelling."[290] Industry commenters argued that a "cap-and-trade program ... is the best way to produce the largest mercury reductions in the most efficient manner."[291] Their views aligned with EPA's recognition that "[a]uthorizing the allowances to be traded maximizes the cost-effectiveness of the emissions reductions in accordance with market forces."[292] These commenters supported the EPA in defending the nationwide interstate cap-and-trade program in the D.C. Circuit.[293]

B. NOx SIP Call

In the NO_x SIP Call, the EPA set emission budgets based in part on the emissions reductions that EGUs could achieve by implementing highly cost-effective controls. The EPA "assumed an emissions trading system" when assessing the costs—and thus the appropriate level of control—for EGUs to reduce emissions of NO_x.[294] Ultimately, the Agency "decided to base the emissions budgets for EGUs on a 0.15 lb/mmBtu trading level of control."[295] To facilitate compliance, the EPA established a NO_x Budget Trading Program— "a compliance mechanism that capitalizes on a proven means of cost effectively meeting a specific emissions budget" that EPA could assist states with administering.[296]

The EPA's identification of EGUs' ability to comply with emission limits by purchasing allowances affected the NO_x SIP Call's emission reductions requirements in several ways. For example, the availability of trading affected EPA's assessment of the cost-effectiveness for the chosen level of controls. At the proposal stage, the EPA explained that its "approach to the NO_x budget component for the electric power industry relies on consideration of the States using [an interstate] cap-and-trade program to reduce emissions from this source category."[297] An

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[289] Comments of the Utility Air Resources Group on the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units and Supplemental Notice, 133 (June 29, 2004).
[290] Joint Brief of State and Industry Respondent-Intervenors, at 25, *New Jersey v. EPA* (May 18, 2007) ("EPA has offered compelling legal justifications for a mercury cap-and-trade program").
[291] Comments of the UARG on the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units and Supplemental Notice, 5 (June 29, 2004).
[292] 70 Fed. Reg. 28606, 28616 (May 18, 2005).
[293] Commenters went even further by arguing that state plans could not deviate from the trading program set up by EPA. *See, e.g.*, Brief of Petitioner UARG, *State of New Jersey, et al. v. EPA*, No. 05-1097 (D.C. Circuit) (Jan. 12, 2007). The argument reasoned that by allowing states to deviate, individual states could "unilaterally establish a new cap that is contrary to EPA's 'best system.'" Brief of Petitioner, at 8.
[294] 63 FR at 57400.
[295] 63 FR at 57401–02.
[296] 63 FR at 57458.
[297] 62 FR 60318, 60349.

interstate trading approach, the EPA explained, "is 25 percent more cost effective (lower in cost per ton reduced) than the use of a comparable traditional command-and-control approach, such as setting rate-based NO_x emission limitations ... at every source."[298]

As a second example, the availability of trading greatly influenced the EPA's decision to base budgets on a uniform rate applicable to all fossil fuel-fired EGUs. One of the decisions the EPA made was to base emissions reductions on a uniform 0.15 lb/mmBtu control level applicable to all EGUs, regardless of the fact that the costs of meeting that standard differ based on EGU fuel type.[299] The EPA explained that these cost differences did not undermine the feasibility of a 0.15 lb/mmBtu approach because EGUs could trade with each other: "Because the EPA envisions a market for NO_x allowances, transfers of allowances from low-cost to high-cost units will tend to equalize the marginal costs of control across all affected units."[300] Because of the availability of trading, it was thus appropriate to consider *average* cost-effectiveness for all EGUs:

> In this rulemaking, EPA has chosen to focus on an average cost-effectiveness measure in identifying highly cost-effective control options for several reasons. Since EPA's determination for the core group of sources is *based on the adoption of a broad-based trading program*, average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs.[301]

Accordingly, although the EPA concluded that, while it might be less cost-effective for some individual EGUs to meet an emission rate through installing on-site controls, overall those EGUs could purchase allowances through a trading program, so that overall the emission rate remained highly cost-effective.[302] This was despite the differences in feasibility for gas and oil-fired EGUs compared to coal-fired EGUs:

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[298] 62 FR at 60349; *see* U.S. EPA, *Responses to Significant Comments on the Proposed Finding of Significant Contribution & Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone*, Docket No. A-96-56 VI-C-1 at 217–18 (Sept. 24, 1998) (stating that in calculating the emissions reductions required from sources in each state, "a cap and trade approach is better than an [alternative] rate-based approach because it is more cost-effective").

[299] U.S. EPA *Responses to Significant Comments on the Proposed Finding of Significant Contribution & Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone*, Docket No. A-96-56 VI-C-1 at 217 (Sept. 24, 1998).

[300] U.S. EPA *Responses to Significant Comments on the Proposed Finding of Significant Contribution & Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone*, Docket No. A-96-56 VI-C-1 at 217 (Sept. 24, 1998).

[301] 63 FR at 57399 (emphasis added).

[302] *See e.g.*, 63 FR 57356, 57399, 57413, 57457 (Oct. 27, 1998); RTC at 217.

> In terms of the proposed level of control on which the trading program budget is based, EPA believes that trading at 0.15 lb/mmBtu is feasible because the proposed limit can readily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_x levels below 0.15 lb/mmBtu and should readily be able to generate emission credits if affected States join a trading program.
> The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/mmBtu emission limit, SCR would generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/mmBtu by installing SCR, it can provide emission credits to another coal-fired boiler and obviate the need for that second boiler to install SCR.
> * * *
> In summary, EPA believes that an emission rate of 0.15 lb/mmBtu reflects the greatest emissions reduction that EPA can confidently conclude is feasible and that is highly cost-effective....[303]

The EPA projected that EGUs with the most cost-effective control possibilities would be "tightly controlled, at significant cost" because of the incentive to sell allowances to EGU owners who "elect to under-control their plants' emission."[304] Accordingly, although the cost to reduce emissions would vary across EGUs, the existing of an emission trading market would level compliance costs. For purposes of modeling the emissions, cost, and economic impact of the NO_x SIP Call:

> Firms are assumed to either buy or sell allowances depending on their costs of control in comparison to the market price of allowances. As the price reacts to changes in demands and supplies of allowances, the market will help ensure that the costs of incremental reductions of NO_x are the same for all participants.[305]

C. CAIR

In 2005, the EPA promulgated an expanded and more stringent transport rule, the CAIR, which regulated SO_2 as well as NO_x emissions from fossil fuel-fired EGUs through a tradable allowance system. Similar to the NO_x SIP Call, the state budgets set by CAIR were based on cost-effective controls on EGUs. The EPA's evaluation of the cost impacts of CAIR assumed that EGUs would be participating in an interstate trading program.[306] The EPA explained that –

[303] 63 FR at 7413 (emphasis added).
[304] NO_x SIP Call RIA at 4-10.
[305] NO_x SIP Call RIA at 4-10
[306] 70 FR 25162, 25196 (May 12, 2005).

> In modeling the CAIR with the IPM, EPA assumes interstate emissions trading. While EPA is not requiring states to participate in an interstate trading program for EGUs, we believe it is reasonable to evaluate control costs assuming states choose to participate in such a program since that will result in less expensive reductions.[307]

EGUs' ability to engage in emission trading similarly factored into EPA's decision to include certain EGUs smaller than 250 MW in the CAIR budget and model rule, despite commenters' claims that inclusion in CAIR would cause these smaller EGUs to shut down.[308] The EPA declined to set a cut-off at 250 MW, noting its projections that "some [EGUs] below 250 MW" would implement highly cost-effective controls, and that smaller EGUs "also have the option to ... purchase allowances" as a means of compliance.[309]

D. CSAPR

In 2011, the EPA promulgated the CSAPR, which regulated interstate transport of SO_2, NO_x, and particulate matter emissions from fossil fuel-fired EGUs through a tradable allowance system.[310] Here, again, the EPA concluded that --

> the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing fuels, reducing utilization, *buying allowances*, or any combination of these actions.[311]

As with the previous two interstate transport programs, the EPA in CSAPR recognized that interstate trading was a particularly well-suited mechanism for addressing emissions from EGUs because of "the power sector's ability to operate as an integrated, interstate system and to promote reliability."[312] As described below, this recognition makes CSAPR merely the most recent in a line of EPA interstate transport rules that took into account trading as a method for EGUs to reduce emissions.[313]

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[307] 70 FR at 25196.
[308] 70 FR at 25276.
[309] 70 FR at 25276.
[310] 76 FR 48208 (Aug. 8, 2011).
[311] 76 FR at 48272.
[312] 76 FR at 48272.
[313] *See, e.g.*, NO_x SIP Call, 63 FR 57356, 57399 (Oct. 27, 1998) (noting that the EPA set state budgets using a uniform emission standard for EGUs in part because those standards were "based on the adoption of a broad-based trading program" that would allow sources with higher marginal costs to more cost-effectively comply); CAIR, 70 FR 25162, 25196 (May 12, 2005) (noting that the EPA set state budgets based on cost-effective controls on EGUs and, in evaluating the cost impacts, "assume[d] interstate emissions trading" because of the reasonable likelihood that states and EGUs would use trading as the way to meet emission requirements).

E. **Regional Haze SIPs**

Under Section 169A of the Clean Air Act, Congress required EPA to promulgate regulations to assure reasonable progress toward meeting the national visibility goal. 42 U.S.C. § 7491(a)(4). Congress further directed EPA to include in its regulations a requirement that States revise their SIPs to include "emission limitations, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." *Id.* § 7491(b)(2). One such measure that Congress deemed necessary to make reasonable progress was a requirement that certain older stationary sources that cause or contribute to visibility impairment "procure, install, and operate, as expeditiously as practicable ... the best available retrofit technology," more commonly referred to as BART. *Id.* § 7491(b)(2)(A). As the statutory language makes clear, Congress envisioned BART as a technology-based standard that would apply at a specific set of sources. Neither Section 169A nor the related Section 169B, *see* 42 U.S.C. § 7492, contain any explicit statutory authorization for EPA to permit States to adopt trading programs or other alternatives to comply with the BART requirement.

In 1999, EPA promulgated the Regional Haze Rule to satisfy Congress's mandate to promulgate regulations that would assure reasonable progress toward the national goal. 64 Fed. Reg. 35,714 (July 1, 1999) (codified at 40 C.F.R. §§ 51.308-309). The Regional Haze Rule allows States to adopt trading programs or other alternatives in lieu of requiring retrofit controls at sources subject to BART. Specifically, the Regional Haze Rule provides:

> A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART.

40 C.F.R. § 51.308(e)(2). EPA provided the following explanation why the Agency had the authority to allow States to adopt trading programs in lieu of BART despite Section 169A(b)(2)(A)'s clear statement that BART was a technology-based standard:

> In recognition of the control and cost efficiencies that can be achieved through trading programs and other alternative measures, EPA is providing States with the opportunity to adopt alternative measures in lieu of BART where such measures would achieve even greater reasonable progress toward the national visibility goal. The overarching requirement of the visibility protection provisions of section 169A is to make reasonable progress toward the national goal of eliminating visibility impairment. If greater reasonable progress can be made through an approach that does not require source specific application of BART, EPA believes that approach would comport with this statutory goal. The EPA reached this conclusion in determining the appropriate measures to address visibility impairment in the Grand Canyon National Park resulting from the Navajo Generating Station. In that case,[314] EPA ultimately chose not to adopt the emission control limits indicated by its BART analysis. Instead, as explained by the Ninth Circuit in upholding EPA's final

[314] Cent. Ariz. Water Conservation Dist. v. EPA, 990 F.2d 1531 (9th Cir. 1993).

> decision, EPA acted within its discretion in adopting an alternative emission control standard ''that would produce greater visibility improvement at a lower cost. Congress's use of the term 'including' in [section 169A(b)(2)] prior to its listing BART as a method of attaining 'reasonable progress' supports EPA's position that it has the discretion to allow States to adopt implementation plan provisions other than those provided by source specific BART analyses in situations where the agency reasonably concludes that more 'reasonable progress' will thereby be attained.'' Under today's final rule, States may elect to adopt an emissions trading program or other alternative measures in lieu of BART so long as greater reasonable progress is made.

64 Fed. Reg. at 35,739 (citation omitted). EPA also explained that a State's trading program could include sources not subject to BART:

> [T]he regional trading program may include sources not subject to BART. Inclusion of such sources provides for a more economically efficient and robust trading program. The EPA believes the program can include diverse sources, including mobile and area sources, so long as the reductions from these sources can be accurately calculated and tracked.
>
> In other words, any sources subject to BART that a State chose to include in a trading program could comply with their obligations through actions taken to reduce emissions by non-BART sources.

In addition to the general provisions at 40 C.F.R. § 51.308(e)(2) discussed above, the Regional Haze Rule also provided a specific option for States on the Colorado Plateau to adopt an SO_2 backstop trading program in lieu of BART. *Id.* § 51.309. Before these States could take advantage of this option, however, the Regional Haze Rule required the Grand Canyon Visibility Transport Commission or another regional planning body to submit a report to EPA that would fill in the details for two aspects of the program: (1) specific emission reduction milestones and (2) documentation for implementing a market trading program in the event that voluntary measures were not sufficient to meet the required milestones. *See* 64 Fed. Reg. at 35,751-52. The Western Regional Air Partnership (WRAP) submitted this report to EPA in 2000, and EPA amended the Regional Haze Rule in 2003 to incorporate the WRAP's recommendations regarding the milestones and trading program. 68 Fed. Reg. 33,764 (June 5, 2003). In a challenge to the 2003 revisions to the Regional Haze Rule, the D.C. Circuit held that EPA had reasonably interpreted Section 169A(b)(2) as permitting alternatives to BART, including trading programs, so long as they achieve greater reasonable progress than would the installation of retrofit controls. *Ctr. for Econ. Dev. v. EPA*, 398 F.3d 653, 660 (D.C. Cir. 2005).

Since 2003, EPA has twice amended the Regional Haze Rule to allow States to rely on other trading programs as alternatives to BART. In 2005, EPA amended the Regional Haze Rule to allow States to rely on the Clean Air Interstate Rule (CAIR) in lieu of BART, 70 Fed. Reg. 39,104 (July 6, 2005), while in 2012, EPA again amended the Rule to allow States to rely on CAIR's predecessor, the Cross State Air Pollution Rule (CSAPR), 77 Fed Reg. 33,642 (June 7, 2012) (codified at 40 C.F.R. § 51.308(e)(4)). In addition to the many eastern States that chose to rely on the CAIR and CSPAR trading programs to satisfy BART requirements, three States and one municipality ultimately submitted SIPs implementing the SO_2 backstop trading program

pursuant to 40 C.F.R. § 51.309, *see* 77 Fed. Reg. 70,693 (Nov. 27, 2012) (New Mexico), 77 Fed. Reg. 71,119 (Nov. 29, 2012) (Albuquerque-Bernalillo County, New Mexico), 77 Fed. Reg. 73,926 (Dec. 12, 2012) (Wyoming), 77 Fed. Reg. 74,355 (Dec. 14, 2012) (Utah), while one State relied on a state-developed trading program pursuant to the general provisions of 40 C.F.R. 51.308(e)(2). *See* 79 Fed. Reg. 39,322 (July 10, 2014) (Connecticut). Each of these trading programs included coal-fired power plants that were subject to BART.

F. Title IV

Title IV expressly reflects Congress' view that an "emission allocation and transfer system" is a suitable alternative compliance method for meeting "prescribed emission limitations."[315] In fact, Congress explained that "through a system of marketable allowances, the reduction programs established by the title maximize the range of choices sources have for complying with their emissions limitation requirements."[316] "On a regional basis," Congress continued,

> this may allow areas with substantial reduction obligations and total costs to lower their net costs by producing and selling 'extra' reductions (*i.e.*, reductions beyond those they are required to achieve) to sources seeking to emit more than is permitted. At the same time, areas facing growth in the [sic] energy demand or units with high emissions control cost on a perton [*sic*] basis find that purchasing excess emissions reductions from plants in other areas, rather than making on-site reductions, enables them to comply with their emissions limitations at a significantly lower cost.[317]

Moreover, by "[a]llowing sources to market 'extra' emissions reductions" a trading system "should also yield important environmental benefits as sources will have strong incentives to make greater-than-required reductions earlier than required. Since sources will enjoy maximum flexibility in responding to those incentives, this approach should also stimulate innovation in pollution-control technology and practices."[318]

Taken together, the flexibility inherent in an allowance based system "minimizes costs and maximizes flexibility and efficiency."[319]

In fact, many sources did comply with their obligations by purchasing allowances. According to a 2001 report by the Energy Information Agency (EIA):

> On January 1, 2000, the electric industry came under Phase II regulations of the Clean Air Act Amendments of 1990. This Act was primarily designed to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxides. Phase I, which began on January 1, 1995, affected 435 generating units and allowed the release of 2.5 pounds of sulfur dioxide per each million Btu of fuel consumed.

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[315] 42 U.S.C. § 7651(b).
[316] S. Rep. No. 101-228, p. 303 (Dec. 20, 1989).
[317] S. Rep. No. 101-228, p. 303 (Dec. 20, 1989).
[318] S. Rep. No. 101-228, p. 303 (Dec. 20, 1989).
[319] S. Rep. No. 101-228, p. 303 (Dec. 20, 1989).

Under Phase II, coverage increased to more than 2,000 units, while restrictions on emissions were set at 1.2 pounds of sulfur dioxide per million Btu of fuel consumed. Since 1995, some generators have over complied with Phase I in order to create excess allowances. This has allowed them to delay enacting additional strategies that would be necessary for compliance with Phase II. [citing Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0582(97) (Washington, DC, March 1997), pg. vii, 45.] Strategies that are being used for compliance include fuel switching/ blending, co-firing with natural gas, *allowance acquisitions*, scrubbers, repowering, and plant retirements.[320]

G. Large municipal waste combustors

State plans for large municipal waste combustors under CAA 111(d) authorize facilities to comply by averaging emission rates of several facilities within a state, and by trading nitrogen oxide (NO_x) emission credits. *See* 40 CFR § 60.3b(d)(1)–(2).

H. Reasonably available control technology

The EPA has long interpreted the reasonably available control technology (RACT) requirements under CAA 172(c)(1) so that the EPA may establish a RACT-level emission reduction obligation on all sources in a category based on a technology that the sources could, on average, implement cost-effectively, and that sources could be expected to meet their emission limits through emissions trading.[321]

XVI. Mercury Air Toxics Rule (MATS) and Off-site Measures

This section provides a summary of the MATS rule that highlights its reliance on the interconnected grid and off-site measures.

The Mercury Air Toxics Standards (MATS)[322] provides another example of EPA interpreting CAA provisions in a way that reflects the reality of the interconnected nature of the electricity sector, and which recognizes the long-standing practice in that sector of retiring or replacing higher-emitting units to meet CAA standards. MATS established national emission standards for hazardous air pollutants (NESHAP) for coal- and oil-fired EGUs. The relevant CAA authority, section 112, generally requires existing sources to comply with applicable standards within three years of the standard's effective date.[323] However, an existing source can

[320] EIA, "Electric Power Annual 2000," vol. 1 (August 2001) 13 http://www.eia.gov/electricity/annual/archive/vol1/0348001.pdf (emphasis added).
[321] *See, e.g.*, NOx Supplement to the Title I General Preamble, 57 FR 55620 (Nov. 25, 1992); EIP Final Rule, 59 FR 16690, 16704 (April 7, 1994).
[322] 77 Fed. Reg. 9,304 (Feb. 16, 2012).
[323] 42 U.S.C. § 7412(i)(3)(A).

obtain an extension of up to one year if the permitting authority determines that the additional time is "necessary for the installation of controls."[324]

In interpreting the phrase "installation of controls" for purposes of coal- and oil-fired EGUs complying with MATS, the EPA was significantly influenced by the uniqueness of the electricity sector:

> [T]his source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including ... derating, or deactivation.[325]

This uniquely interconnected system drove the EPA to propose a reasonable interpretation of "necessary for installation of controls" that encompassed not only add-on controls made at an existing unit, but also the "replacement of an existing unit with a cleaner one."[326] At the proposal stage, the Agency proposed to reasonably interpret "necessary for the installation of controls" to allow for an extension if necessary for

> the construction of *on-site replacement power* (*e.g.*, a case when a coal unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle gas turbine or simple cycle gas turbine ...)."[327]

Commenters representing owners and operators of coal-fired EGUs widely praised the Agency's uniquely tailored interpretation, and urged the Agency to interpret "installation of controls" even more broadly to encompass a number of *off-site* actions that EGUs owners can take to enable emission reductions at an existing coal-fired EGU.

For example, UARG urged EPA to consider certain transmission system upgrades as an "installation of controls" that would merit an extension:

> UARG supports EPA's decision to encourage States to grant a one-year extension in cases where there is construction of on-site power replacement. *UARG believes there are other cases that could be considered "installation of controls."* One example is *a transmission system upgrade* that is needed to bring power generated at other locations to replace the power generated by the retiring unit.[328]

Southern Company similarly urged that EPA's interpretation should apply to replacement generation constructed anywhere -- not just at the site of the EGU:

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[324] 42 U.S.C. § 7412(i)(3)(B).
[325] 77 Fed. Reg. at 9,410.
[326] 76 Fed. Reg. 24,976, 25,055.
[327] 76 Fed. Reg. 24,976, 25,055 (emphasis added).
[328] UARG's MATS comment (#17775) at 244 n.292.

> Regardless of where the replacement power is built (either by the utility or purchased as part of a power purchase agreement), the one-year extension [for installation of controls] should be allowed for retirement, construction of replacement power, and construction of new and upgraded transmission lines that bring replacement power from new or existing generation units.[329]

American Electric Power (AEP) commented that EPA's proposed interpretation limiting "installation of controls" to on-site generation was "too limiting" in light of the ability to construct effective replacement generation in other locations, including with natural gas:

> AEP appreciates that EPA includes construction of on-site replacement power as an eligible activity for a compliance extension should units be retired and replaced. However, the reference to "on-site" replacement generation is too limiting as existing sites, among other technical factors, may not have easy access to natural gas supply, which will be the likely fuel source for much of the replacement generation. Additionally, replacement generation may be added at a single larger site to replace retired generation at number of smaller sites. Thus, *AEP requests that ANY capacity being added to off-set unit retirements automatically be eligible for the compliance exemption*.[330]

A number of these commenters indicated that a retirement of an EGU should qualify as an "installation of controls," regardless of whether there will be replacement power. For example, AEP contended that an extension would be necessary for the installation of controls "if required state and federal regulatory approvals to retire the capacity cannot be obtained."[331] The Florida Electric Power Coordinating Group, which represents utilities and rural electric cooperatives in that state, commented that it

> supports EPA's interpretation that building replacement power meets the requirements in Section 112(i)(3) "to install controls," and *requests that EPA apply this provision to all retirements*, and not limit it to retirements where replacement power will be built at the same site.[332]

In light of these and many other supportive comments, in the final MATS rule the EPA formally interpreted "necessary for the installation of controls" as applying to a wide variety of on- and off-site actions that the owners and operators of EGUs can make to reduce emissions, which are made possible only because of the unique, interconnected nature of the electricity sector. Specifically, the EPA interpreted "installation of controls" to include not only construction of on-site replacement power, but also retirements, construction of off-site generation, or transmission upgrades. Accordingly, the EPA advised state permitting authorities

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[329] Southern Co.'s MATS comment (#18023) at 199.
[330] AEP's MATS comment (#19114) at 28. AEP further suggested that other off-site measures should qualify for the extension, such as "if transmission improvements are needed" or "additional gas supply lines must be constructed or replaced"). *Id.* at 20.
[331] AEP's MATS comment (#19114) at 20.
[332] Fla. Elec. Power Coordinating Grp.'s MATS comment (#17368) at 5–6.

that any of the following would "reasonable justification" for providing up to an additional year of compliance time as "necessary for the installation of controls":[333]

> (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.[334]

The EPA believed that this interpretation was fully consistent with the requirement the fact that the extension "on its face applies to individual sources ...."[335] This interpretation nevertheless complies with that source-specific requirement because off-site transmission upgrades, on- and off-site replacement generation, and retirement of the affect coal-fired EGU itself are all techniques that allow the EGU to reduce its emissions – in MATS, mercury and other hazardous emissions; in this rule, CO2 emissions.

At least some sources have taken advantage of the EPA's offer by seeking and obtaining extensions for reliability-delayed retirements coupled with construction of replacement generation.

XVII. Shifts in Generation Dispatch

This section provides additional information to support the explanation in section V.A., B., and V.D. for why building block 2, which entails shifting generation – sometimes called load shifting -- from (higher emitting) fossil steam generators to (lower emitting) NGCC units, is part of the BSER.

Load shifting has been recognized is an "easy and fairly inexpensive strategy" that "may be used in conjunction with other control measures" for "emission reduction."[336] Moreover, it has been recognized as a pollution control technique as early as 1968, when it was included in the "Chicago Air Pollution System Model" for controlling incidents of extremely high

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[333] In the final interpretation, the EPA interpreted the word "necessary" to mean that an EGU's continued operation is "required [to ensure] reliability" while the replacement power is being generated. *See* 77 Fed. Reg. 9,304, 9,410 (Feb. 16, 2012).

[334] 77 Fed. Reg. 9,304, 9,410 (Feb. 16, 2012). In each of these cases, the EPA included reliability concerns as a component of when the extension would be justified. The requirement to demonstrate reliability concerns flowed from EPA's interpretation of the word "necessary" in the phrase "necessary for the installation of controls." *See id.* at 9,410–11. Under each of the three options, "installation of controls" was interpreted to mean retirement, construction of new off-site generation, or transmission upgrades. *Id.*

[335] *See* MATS RTC at 313 (responding to comment 42).

[336] Donald S. Shepard, "A Load Shifting Model for Air Pollution Control in the Electric Power Industry," Journal of the Air Pollution Control Association, Vol. 20, No. 11, p. 760 (Nov. 1970).

pollution.[337] The report recognized, as an initial matter, that the Commonwealth Edison Company (CECO) was "constrained to meet the total load demand" but that "load reduction at one plant or even a number of plants is usually feasible by shifting the power demand to other plants in the system."[338] As a result, the report noted, "load shifting within the physical limits of the CECO system ... may be a highly desirable control mechanism."[339] The report also predicted that "[i]n the future, it may be possible to form reciprocal agreements to obtain 'pollution abatement' power from neighbor companies during a pollution incident and return this borrowed power at some later date."[340]

XVIII. Limiting Principles and Commenters' Hypothetical Examples

Several commenters assert that the EPA's interpretation of the BSER lacks a limiting principle and would therefore allow the EPA to impose intrusive controls on other sectors. These commenters offer hypothetical examples of the types of rules that EPA could promulgate. For example, one commenter claims that the EPA's interpretation at proposal "would provide little check on the level of output [the] EPA could mandate" through reduced utilization.[341] Another claims that building blocks 2 and 3 are akin to "requiring car owners to take the bus more" and to "requiring the [purchase] of more electric vehicles".[342] Still others argue that "the agency could require states to mandate that consumers dim their lights on alternate days, limit home builders to constructing only two-story buildings, or shutter public schools during periods of peak energy usage"[343] or in setting other standards the EPA "could require Americans to use scythes ... force businesses to ship their products by rail ... [and] force business to convert to 'paperless' workplaces and outlaw printing emails and other documents."[344] And as a last example, one set of comments explains that "if the EPA were to apply a 'beyond the source' approach to GHG standards of performance and emission guidelines for the gasoline refining industry, it might require refiners to 'redispatch' fuel production from their facilities to less-utilized existing biofuel facilities, or it might require states to invest in constructing new biofuel facilities."[345]

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[337] E.J. Croke, et al., "Chicago Air Pollution System Model, Third Quarterly Progress Report," Chicago Department of Air Pollution Control, p. 186 (1968) (discussing the feasibility of "Control by Load Reduction" in combination with load shifting as applied to the Commonwealth Edison Company), *available at* http://www.osti.gov/scitech/servlets/purl/4827809. The report also considered "combining fuel switching and load reduction" as a possible air pollution abatement technique. *See id.* at 188.
[338] *Id.*
[339] *Id.*
[340] *Id.* at 187.
[341] EEI Comments, pp. 284-85.
[342] UARG Comments, p. 3.
[343] Comments of Attorney Generals of Oklahoma, West Virginia, *et al.*, p. 8.
[344] Natural Rural Electric Cooperative Association Comments, pp. 22-23.
[345] Comments of Hon. Charles W. Pickering, Sr., and Hon. Thomas Scott, p. 25.

Our final interpretation of the BSER is bounded by several principles, which take the form of significant constraints included in the provisions of CAA section 111(d)(1) and 111(a)(1).[346]

A. Constraints under CAA requirements for determining the BSER

We discuss our interpretation of section 111(a)(1) and (d)(1) in section V.A. and V.B. of the preamble, and focus particularly on the constraints in section V.B.3.(a) and (c)(8). As we note in the preamble, the first constraint is that the BSER must assure emission reductions from the affected sources. Under section 111(d)(1), the states must submit state plans that "establish[] standards of performance for any existing source," and, under section 111(a)(1) and the EPA's implementing regulations, those standards are informed by the EPA's determination of the best system of emission reduction adequately demonstrated. Because the emission standards must apply to the affected sources, actions taken by affected sources that do not result in emission reductions from the affected sources—for example, offsets (e.g., the planting of forests to sequester CO_2)—do not qualify for inclusion in the BSER.[347]

The second constraint is that because the affected EGUs must be able to achieve their emission performance rates through the application of the BSER, the BSER must be controls or measures that the EGUs themselves can implement. Moreover, as noted, the D.C. Circuit has established criteria for achievability in the section 111(b) case law; e.g., sources must be able to achieve their standards under a range of circumstances. If those criteria are applicable in a section 111(d) rule, the BSER must be of a type that allows sources to meet those achievability criteria.

The third constraint is that the system of emission reduction that the EPA determines to be the best must be "adequately demonstrated." To qualify as the BSER, controls and measures must align with the nature of the regulated industry and the nature of the pollutant so that implementation of those controls or measures will result in emission reductions from the industry and allow the sources to achieve their emission performance standards. The history of the effectiveness of the controls or other measures, or other indications of their effectiveness, are important in determining whether they are adequately demonstrated.

The fourth constraint, or set of constraints, is that the system of emission reduction must be the "best," "taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements." As noted, in light of the D.C. Circuit case law, the EPA has considered cost and energy factors on both an individual source basis and on the basis of the nationwide electricity sector. In determining what is "best," the EPA has

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[346] *See Lawson v. FMR LLC*, 134 S. Ct. 1158, 1169 (2014) (noting that "limiting principles may serve as check against overbroad applications").

[347] As discussed in section VIII of the preamble, a mass-based state plan must address the potential for "leakage" and, as one of its options, may account for CO_2 emissions from new and existing sources under a joint cap implemented under state law. This approach does not violate the constraint described in the accompanying text, in fact, it is intended to assure that existing sources do achieve emission reductions.

broad discretion to balance the enumerated factors. In past actions under section 111 for the electricity sector and other sectors (and in past actions under other CAA provisions for the electricity sector), we have taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production. This approach has been inherent in our past interpretation and application of section 111 and we maintain this interpretation in this rulemaking.[348] Thus, our approach for this rulemaking is that affected EGUs can implement a system of emission reduction that will reduce the amount of their emissions without reducing overall electricity generation. This approach takes into account costs by minimizing economic disruption, as well as maintaining the nation's energy requirements, by avoiding the need for reductions in the aggregate amount of electricity available to the consumer, commercial, and industrial sectors. After taking into account costs and energy requirements in this manner, we have concluded that building blocks 2 and 3 are part of the best system of emission reduction adequately demonstrated. Building block 4, however, is outside this paradigm as it targets consumer-oriented behavior and demand for electricity, which would reduce the aggregate amount of electricity to be produced.

These criteria ensure that the selected system of emission reduction is a reasonable exercise of the Administrator's discretion.[349] Section 111(a)(1) grants broad discretion to the Administrator but nonetheless spells out "'what the [EPA] should do and how it should do it, and sets out specific directives to govern particular situations.'"[350] Nonetheless, the mere fact that "a system of emission reduction" embodies a broad set of measures does not mean that EPA's discretion is unbounded. In fact, the Supreme Court suggested in *AT&T v. Iowa Utilities Board* that a rule can apply a broadly defined statutory term even where other terms limited an agency's

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[348] As we note in section V.A., in rulemaking under section 111, the EPA must necessarily take into account the nature of the industry, the nature of the air pollutant, and the types of controls or measures available for that industry to reduce that air pollutant. In previous section 111 rulemakings, on-site controls or measures that applied to the design or operations of the affected sources were generally available. In some cases, as noted in section V.B. of the preamble and section XV of this Legal Memorandum, off-site fuel cleaning measures were also available and, in the case of section 129/111(d) rules, waste reduction measures were also available, in accordance with CAA section 129(a)(3). Accordingly, the EPA interpreted section 111 in those contexts. This rulemaking presents a unique set of circumstances, including the global nature of CO_2 and the emission control challenges that CO_2 presents (which limit the availability and effectiveness of control measures), combined with the facts that the electric power industry (including fossil fuel steam generators and combustion turbines) is highly integrated, electricity is fungible, and generation is substitutable (which all facilitate the generation shifting measures encompassed in building blocks 2 and 3). Our interpretation of section 111 as focusing on limiting emissions without limiting aggregate production must take into account those unique circumstances.

[349] *See, e.g.*, *Gas Appliance Mfrs. Ass'n v. DOE*, 998 F.2d 1041, 1045 (D.C. Cir. 1993) (identifying a "limiting principle inherent in 'economic cost and benefit'").

[350] *Mistretta v. U.S.*, 488 U.S. 361, 378-79 (1989) (upholding Congressional delegation to the U.S. Sentencing Commission to set guidelines under Sentencing Reform Act of 1984 because "[t]he Act sets forth more than merely an 'intelligible principle' or minimal standards.").

access to the full breadth of that definition in carrying out the statutory directive.[351] Here, Congress established several constraints (identified above) that the Administrator must consider before she may carry out her duties under section 111. Thus, it is not necessary to deduce an additional limitation on the Administrator's discretion under section 111(a)(1) to avoid the hypothetical intrusive regulatory examples that some commenters describe.

As we discuss in section V. of the preamble, we undertake a three-step analysis under section 111. First, we survey a range of adequately demonstrated systems of emission reduction; second, we determine the best of those systems, taking into account cost and other factors; and third, we select an achievable emission limit based on application of the BSER. Thus, in accordance with our interpretation, we undertake a pollutant-specific and source-category-specific evaluation. As a result, the BSER is unique to each industry and even may be different for new and existing sources.

With these principles in mind, we now turn to address commenters' hypotheticals.

B. Commenters' Hypotheticals

1. Consumer Products: Pulp and Paper

Commenters assert that when EPA promulgated and later revised NSPS for kraft pulp mills, it never considered basing the standard of performance on requiring increased use of recycled paper to reduce kraft pulp mill operations, even though such a measure arguably would have reduced emissions from kraft pulp mills. Commenters argue that applying EPA's proposed interpretation of the BSER could lead EPA to adopt standards of performance for kraft pulp mills that are based on efforts to reduce demand for new paper, such as requiring office buildings to implement paper recycling programs, convert to paperless workplaces, outlaw printing, or encouraging credit card companies to provide paperless billing to customers.

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[351] *AT&T Corp. v. Iowa Utilities Board*, 525 U.S. 366, 370-71 (1999). In *AT&T Corp.*, the Court addressed the argument "that the FCC included within the features and services that must be provided to competitors under Rule 319 items that do not (as they must) meet the statutory definition of 'network element'". *Id.* at 386. After reciting the definition of a "network element," the Court recognized that the term is broadly defined and rejected arguments that it "must be part of the physical facilities and equipment used to provide local phone service." *Id.* at 387. Accordingly, the Court deemed the FCC's application of the term "eminently reasonable." *Id.*, citing *Chevron*, 467 U.S. at 866. The Court went on to conclude, however, "that the FCC did not adequately consider the 'necessary and impair' standards when it gave blanket access to these network elements, and others, in Rule 319." *AT&T* at 387. The Court reasoned that the FCC needed "to apply some limiting standard, rationally related to the goals of the Act" when determining what network elements should be made available, which the Act explained required the FCC to consider whether "(A) access to such networks elements … is *necessary*; and (B) the failure to provide access to such network elements would *impair* the ability of the telecommunications carrier seeking access to provide the services that it seeks to offer." *Id.* at 388. Thus, because the FCC neglected to consider the necessary and impair standards, the Court vacated Rule 319 for failing to suffice as a reasonable interpretation of the statute.

Basing the BSER for kraft pulp mills on demand-side activities would not qualify as a system of emission reduction in accordance with our interpretation of section 111, including the constraints noted above. First, we do not interpret section 111(a)(1) to authorize measures that target consumer-oriented behavior as the BSER.

Moreover, even if such activities could be considered under section 111, commenters have not shown that such measures would satisfy other of the criteria of section 111(a)(1) for this industry.

Several of commenters' hypotheticals are not systems of emission reduction that owners or operators of kraft pulp mills could undertake to achieve emission limits. While governments could, in theory, require that office buildings implement paper recycling programs, require conversion to paperless workplaces, or outlaw printing, the owners or operators of kraft pulp mills could not.

In addition, commenters' hypotheticals concerning recycling do not take into account limits on the substitutability of recycled paper in the marketplace. Paper is significantly less fungible than electricity, which raises issues as to whether commenters' hypotheticals could qualify as adequately demonstrated systems of emission reduction. Recycled paper is not uniformly substitutable in the marketplace because of the physical properties of the final product. First, paper can only be recycled a finite number of times. Every time paper is recycled, the cellulosic fibers that make up the sheet become shorter. After being recycled five to seven times, the fibers are too short to bond to form a new sheet of paper, therefore, new fibers must be added to produce the sheet. Second, some paper products require strength properties that are not achievable with recycled fibers because recycled fibers weaken each time they go through the recycling process. For example, grocery bags need very high tensile and tear properties so that the bags don't break when people use them to carry their groceries, and therefore, are made with new, long softwood fibers instead of short recycled fibers. Some paper products require very clean fibers such as book papers and personal hygiene products. The recycling process does not remove 100 percent of the contaminants, so recycled fiber cannot be used for these products.

By the same token, commenters' hypotheticals concerning paperless documents and communications do not take into account the fact that, although fossil fuel-fired generated electricity and renewable generated electricity are fungible, paperless communications and printed documents are not fungible. This lack of fungibility places limits on the extent to which the commenters' hypotheticals would constitute adequately demonstrated systems of emission reduction.

Further, commenters have not shown that such measures are adequately demonstrated for the kraft pulp mill industry. Commenters have not explained what actions owners or operators of kraft pulp mills could undertake to implement such measures to reduce emissions from their sources, and we are not aware of any history of any of those entities doing so. Moreover, due to the trade-sensitive nature of the industry, the extent to which demand-side measures would actually reduce emissions from kraft pulp mill sources is not clear because (i) a large percentage (in 2013, approximately 40 percent) of the domestically recovered paper and paperboard were exported to China and other nations for recycling and producing paper in their own countries;

and (ii) it may be possible for pulp and paper mills to produce more paper products and sell them overseas or produce other types of products.

In addition, commenters have not shown that their hypotheticals meet the other criteria for the BSER, including the amount of emission reduction and the costs. For instance, commenters have not identified any business practices in the kraft pulp mill industry that could help lessen the costs of implementing such measures. In addition, it is not clear whether owners or operators of kraft pulp mills could recover the costs of the hypothesized measures, in light of foreign competition.

Lastly, commenters have not shown how we could quantify an achievable limit based on application of such measures, that is, how sources could be credited for such measures. As discussed in section V of the preamble and supporting documents, for renewable energy, the REC market is well-established and generation tracking systems are well-established; as a result, systems can be developed for crediting the affected EGUs subject to this rulemaking for generation shifts and the development or incremental renewable energy. Those types of mechanisms do not exist in the pulp and paper industry.

2. Other Energy Products: Oil and Gas Refineries

Commenters argue that the EPA could apply its proposed interpretation of the BSER to take economy-wide measures that reduce the demand for gasoline, including increased motor vehicle fuel efficiency standards, efforts to promote electric vehicles and natural gas-fueled vehicles, and investments in mass transit systems. Commenters claim that EPA could require businesses to make greater use of telecommuting in order to encourage their employees to drive less. Commenters also argue that the EPA could apply its proposed interpretation of the BSER to require refineries to redispatch fuel production from their facilities to less-utilized existing biofuel facilities or require states to invest in constructing new biofuel facilities.

The commenters' hypotheticals concerning demand-side activities are similar to those concerning kraft pulp mills, noted above, and for much of the same reasons, basing the BSER for refineries on demand-side activities would not qualify as a system of emission reduction in accordance with our interpretation of section 111 and the constraints noted above. First, we do not interpret section 111(a)(1) to authorize measures that target consumer-oriented behavior as the BSER.

Moreover, even if such demand-side activities could be considered under section 111, commenters have not shown that such measures would satisfy other criteria of section 111(a)(1) for this industry.

Commenters' demand-side hypotheticals are not systems of emission reduction that owners or operators of refineries could undertake to achieve emission limits. While governments could require increased motor vehicle fuel efficiency standards, promote electric vehicles and natural gas-fueled vehicles, invest in mass transit systems, and require businesses to make greater use of telecommuting in order to encourage their employees to drive less, the owners or operators of refineries could not do most of those things.

Further, commenters have not shown that such demand-side measures are adequately demonstrated for refineries. Commenters have not explained what actions owners or operators of refineries could undertake to implement such measures to reduce emissions from their sources, and we are not aware of any history of any of those entities doing so. Moreover, due to the nature of the industry, it is not clear that demand-side measures would actually reduce emissions from refineries because in that industry, suppliers (that is, refineries) and consumers are not as well integrated as in the electricity sector. Moreover, reducing domestic demand could simply lead refineries to maintain the same level of production and sell more fuel overseas. Nor is it clear that refineries could recover the costs of "redispatch" to biofuels. As a study by the Duke University Nicholas Institute for Environmental Policy Solutions stated with respect to these points:

> The electricity produced by electric-generating units is almost entirely consumed domestically, and effectively faces no real international competition, but refined petroleum products are internationally traded. The price of refinery inputs (crude oil) and products (gasoline, among others) are set in global markets. Therefore, U.S. producers may have exceedingly limited ability to pass the cost of regulation to consumers. Many refined products are substitutable, potentially shifting production (and emissions) to other countries not subject to regulation, a phenomenon known as "leakage." On the other hand, different states within the United States have different requirements for products such as gasoline. Therefore, foreign competitors may have to adjust their product for various U.S. markets.
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> Because elements of pricing and reliability are regulated at the federal and state level, many electric generators do not face a market in the same way that refineries do. Some generators sell into competitive wholesale markets, but others are part of a vertically integrated market with regulated investment and rates of return. Refineries are subject to no comparable price regulation, further hampering their ability to pass along costs in the form of consumer prices.
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> Electric-generating units are physically connected to one another through the transmission and distribution grid; refineries are not connected through such a system. The connectivity of the former argues for a "systems-based" approach to selection of a best system of emissions reduction on which EPA is required to base a performance standard under the Clean Air Act. Such an approach may be legally more challenging to argue for in the context of the refining sector because operation of one refinery does not as heavily influence operation of another.[352]

In addition, commenters have not shown that their demand-side hypotheticals meet the other criteria for the BSER, including the amount of emission reduction and the costs. For

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[352] Kristie Beaudoin, *et al.*, "Regulating Greenhouse Gases Sector by Sector under the Clean Air Act: How Well Does the Electric-Generating Unit Experience Translate to Petroleum Refineries?" NI PB 14-02, pp. 2-3, Nicholas Institute for Environmental Policy Solutions, Duke University, *available at* https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_pb_14-02_0.pdf

instance, commenters have not identified any business practices in the refineries industry that could help lessen the costs of implementing such measures.

Lastly, commenters have not shown how the EPA could quantify an achievable limit based on application of such demand-side measures, that is, how sources could be credited for such measures.

With respect to commenters' hypotheticals concerning "redispatch" to biofuel, the EPA interprets this comment as suggesting that, to reduce refineries' GHG emissions under section 111, the EPA might require refineries to reduce their emissions by having them substitute biofuels for some of the gasoline or diesel they sell (i.e., "redispatch" from gasoline/diesel to biofuels), which would presumably decrease the amount of gasoline or diesel they would refine, thereby reducing their emissions. The EPA notes that Congress has already established a program under which refiners are required to incorporate certain amounts of biofuels (or renewable fuels) in the transportation fuels they sell. Under the Renewable Fuel Standard (RFS) program, required by section 211(o) of the Clean Air Act, as amended by the Energy Independence and Security Act of 2007 (EISA), Congress required refiners and importers to ensure that statutorily-specified amounts of renewable fuels be included in the transportation fuels they sell as a way to reduce life-cycle GHG emissions[1] of transportation fuels, to reduce the amount of gasoline and diesel fuel used in the US, and for other purposes. Congress set ambitious targets for the amount of renewable fuels it required. Due to constraints in the fuel market to supply increasing volumes of renewable fuels to consumers, EPA has concluded the volume targets for total renewable fuel specified by Congress in the Clean Air Act for 2014, 2015 and 2016 cannot be achieved. Accordingly, the EPA has proposed to reduce the volumes of renewable fuels refiners are required to meet (compared to the levels specified in the statute).

The RFS program is designed to reduce the lifecycle GHG footprint associated with transportation fuels. It is not primarily directed at reducing refinery emissions, but refinery emissions are included in the baseline of the life-cycle emission calculation. Given the fact that the Clean Air Act's target for total renewable fuel use is higher than can be met currently, and given the EPA's authority to raise the mandated volume levels under section 211(o) in the future if appropriate, it is unclear under what circumstances it would ever make sense for the EPA to require refineries to substitute biofuels sales for gasoline or diesel sales as part of their transportation fuels sales as a means of reducing refinery emissions under section 111. In any event, it is instructive to note that, in the RFS program, as a way of addressing climate change, Congress required producers of a high-carbon intensity product (measured on a life-cycle basis) to substitute for it a lower-carbon intensity product, knowing that at least some refiners would need to purchase that lower-carbon intensity product (or its environmental attribute) from a third party.

In addition, commenters have not shown that "redispatch" to biofuels would constitute an adequately demonstrated system of reduction of emissions from refineries. It bears noting the very different situations of power production and petroleum refining in assessing the suitability of "redispatch" to biofuels as a system of emission reduction. As we explain throughout the preamble, the power industry is such a highly integrated system that it can be best understood as a "complex machine;" its product, electricity, is fungible, and the means of generating electricity are substitutable; electricity cannot be stored in substantial amounts or exported to the global

market; and electricity supply is heavily regulated and must be instantaneously balanced with demand at all times because downstream consumers are physically connected to suppliers. These attributes make the power sector uniquely situated to taking advantage of emission control techniques that are not commonly applied in other industries, including emissions based on substitute generation or redispatch. The refinery industry, on the other hand, is not as highly integrated and is trade-sensitive, as the Nicholas Institute study quoted above notes. Most biofuels are also not completely fungible with the gasoline or diesel they replace. . Even if a section 111 rule were to require greater use of biofuels, refinery emissions would not necessarily decrease. Refiners could continue to refine the same amount of gasoline or diesel by selling more of it overseas. Accordingly, commenters have not shown that this technique is adequately demonstrated for reducing emissions from the refining industry. The commenters have not addressed whether, for the same amount of fuel (measured by energy content), a refiner's emissions are higher or lower than a biofuel facility's emissions. They also have not addressed the cost implications associated with "redispatch" in the refinery industry, or other nonair environmental impacts, or energy impacts.

The commenters' hypothetical requirement for states to invest in constructing new biofuel facilities is inapposite. The CPP does not require states to construct new electric generating units.

3. Construction Products: Portland Cement and Steel

Commenters argue that applying EPA's proposed interpretation of the BSER could require states to tax the consumption of products (e.g., Portland cement) from that process and subsidize its substitutes (e.g., plastic construction materials) or require construction contractors to buy less steel (or pay much more for a limited quantity of steel) to use in their buildings or impose building heights.

The commenters' hypotheticals concerning demand-side activities are similar to those concerning pulp mills refineries, noted above, and for much the same reasons, basing the BSER for Portland cement or steel manufacturers on demand-side activities would not qualify as a system of emission reduction in accordance with our interpretation of section 111 and the constraints noted above.

First, we do not interpret section 111(a)(1) to authorize measures that target consumer-oriented behavior as the BSER.

Moreover, even if such activities could be considered under section 111, commenters have not shown that such measures would satisfy other of the criteria of section 111(a)(1) for this industry.

Some of commenters' hypotheticals are not a system of emission reduction that owners or operators of Portland cement plants or steel manufacturers could undertake to achieve emission limits. While governments could, in theory, tax the consumption of Portland cement and subsidize its substitutes, owners or operators of Portland cement plants could not; and while governments could, in theory, require construction contractors to buy less steel or impose building heights, steel manufacturers could not.

In addition, commenters' hypotheticals concerning plastic construction materials do not take into account limits on the substitutability of construction products in the marketplace. Construction products are significantly less fungible than electricity. For example, alternative cements are not normally considered suitable for structural applications, including reinforced concrete beams and columns. Moreover, unlike the power sector, domestic cement manufacturers are trade-sensitive and could face significant loss in market share to cement importers. Thus, these characteristics raise several issues as to whether commenters' hypotheticals could qualify as adequately demonstrated systems of emission reduction.

Further, commenters have not shown that such measures are adequately demonstrated for the Portland cement or steel industries. Commenters have not explained what actions owners or operators of Portland cement plants or steel manufacturers could undertake to implement such measures to reduce emissions from their sources, and we are not aware of any history of any of those entities doing so.

Moreover, commenters have not shown that their hypotheticals meet the other criteria for the BSER, including the amount of emission reduction and the costs. For instance, commenters have not identified any business practices in the affected industries that could help lessen the costs of implementing such measures. As with other trade-sensitive industries, it is also not clear whether owners or operators of cement and steel manufacturers could recover the costs of the hypothesized measures in light of foreign competition.

In addition, commenters have not shown how we could quantify an achievable limit based on application of such measures, that is, how sources could be credited for such measures.

4. Mobile Sources

Commenters assert that EPA's proposed interpretation of the BSER under section 111 could lead to similar interpretations under Title II. Commenters claim EPA could attempt to reduce vehicle tailpipe emissions by requiring individuals to reduce vehicle use altogether by working from home once a week or require states to force consumers to use motorcycles or bikes. Instead of regulating emissions from trucks, EPA could require states to force businesses to ship products by rail. Instead of regulating emissions from lawnmowers, EPA could require the use of scythes or old fashioned reel mowers.

Commenters' hypotheticals do not account for the different statutory requirements for regulating stationary sources under section 111 and mobile sources under Title II. Implementation of Title II standards is through certification of the motor vehicle or engine as meeting a specific standard rather than through programs based on influencing consumer behavior with a potential indirect effect on emissions. *See* CAA section 203, 206 (a), (b), and (c). Moreover, whereas section 111 standards are based more broadly on systems of emission reduction, typically, Title II standards are based on "the application of technology which the Administrator determines will be available for the model year to which such standards apply, giving appropriate consideration to cost, energy, and safety factors associated with the application of such technology." CAA section 202(a)(3)(A)(i)(heavy-duty vehicles or engines); CAA section 202(l)(2) (mobile source-related air toxics); CAA section 213(a)(3 (nonroad engines and vehicles); see also CAA section 202(a)(1)-(2) (standards for new motor vehicles or

new motor vehicle engines are to "take effect after such period as ... necessary to permit the application and development of the relevant technology"); CAA section 219(a) & (d) (urban bus standards). Given the very different regulatory programs, our interpretation of section 111 would have minimal, if any, precedential effect der Title II.

C. *Electric Power Supply Association v. FERC*

Some commenters referred to *Electric Power Supply Association v. FERC*, (*EPSA*) the recent D.C. Circuit decision in which the Court searched for a limiting principle in a case involving statutory construction where the central question concerned an agency's jurisdiction.[353] The Court rejected FERC's rationale that the Federal Power Act grants the commission authority over demand response resources in the wholesale market. In that case, the court viewed FERC's interpretation as too expansive and sought to discern a limiting principle "in the context of the overall statutory scheme."[354] The court concluded that FERC's reach "'extend[s] only to those matters which are not subject to regulation by the States'" and "[a]bsent a 'clear and specific grant of jurisdiction' elsewhere, the agency cannot regulate areas left to the states."[355] Some commenters cite this decision to argue that "[t]here is a long history of federal courts invalidating similar attempts by administrative agencies to unmoor limited grants of legislative authority ... by transforming them into broad mandates that aggrandize agencies' power at the expense of the states and the regulated community."[356] *Certiorari* was granted in May 2015.

It is not necessary to delineate a "limiting principle" of the sort at issue in *EPSA* for this rule because, in interpreting the CAA, we do not disrupt the federal-state relationship under section 111(d)[357] nor do we assert jurisdiction over any entities other than the regulated EGUs. In

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[353] *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014).
[354] *Id.* at 221, citing *Brown & Williamson*, 529 U.S. at 132-33.
[355] *EPSA*, 753 F.3d at 221-22 (internal citations omitted).
[356] Comments of Attorney Generals of Oklahoma, West Virginia, *et al.*, p. 11.
[357] This is so because a standard of performance simply reflects a numerical limit for emissions—sources are free to choose the techniques and means of actually meeting that limit as may be appropriate for their individual situations. In fact, the EPA is expressly precluded from mandating specific controls except in certain limited circumstances. *See* 42 U.S.C. § 7411(b)(5). For instance, the EPA is authorized to mandate a particular "design, equipment, work practice, or operational standard, or combination thereof," when it is "not feasible to prescribe or enforce a standard of performance". 42 U.S.C. § 7411(h)(1). Section 111(h) also highlights for us that while "design, equipment, work practice, or operational standards" may be directly mandated by the EPA, section 111(a)(1) encompasses a broader suite of measures for consideration of the BSER.

Likewise, a section 111(d) emission guideline solely presents states with the minimum criteria for a suitable state plan—states are free to adopt locally appropriate means for establishing, implementing, and enforcing standards of performance and may also consider a source's remaining useful life (among other factors) when applying a standard of performance to a particular source. States are also free to adopt or enforce more stringent standards in accordance with section 116. This rule does nothing to disrupt this relationship between the EPA and the states. Generally speaking, the CAA defines the parameters for federal and state

Electric Power Supply Association, the D.C. Circuit was concerned that FERC improperly intruded into "areas left to the states" and so believed a limiting principle was necessary to cabin the agency's jurisdictional reach under the Federal Power Act.[358] Here, our interpretation of the BSER for purposes of establishing an emission guideline under section 111(d) does not intrude on any area "left to the states." In fact, we make clear that states have significant flexibility in preparing state plans, including through the state measures approach. Additionally, our final interpretation of the BSER does not expand our authority over uncovered entities nor would it impose any environmental requirements on such entities. Our interpretation merely aligns our review of control options to the real-world practices of affected EGUs.

D. Commenter assertions concerning "beyond the source" considerations and section 111(a)(7)

Some commenters assert that section 111(a)(1) should be interpreted to foreclose "beyond the source" considerations as a limiting principle. We explain in section V.B. of the preamble the reasons why we disagree with this view. Here, we will focus on the defined term: "technological system of continuous emission reduction."[359] Under section 111(a)(7), Congress defines a technological system of continuous emission reduction as:

(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or
(B) a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.

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cooperation for air pollution prevention and control, and section 111 is no exception. In fact, Congress expressly recognized that section 111(d) authorizes the Administrator to determine the BSER and develop emission guidelines, which are then used by the states to establish standards of performance. Only where a state "fails to submit a satisfactory plan" will the Administrator prescribe a federal plan in its place. [358] One way of looking at this case is as a simple application of the federalism canon rather than as imposing a limiting principle requirement on agency interpretations. *See American Farm Bureau Federation*, No. 13-4079, slip op. at 42-48, citing *Gregory v. Ashcroft*, 501 U.S. 452, 461 (1991) (explaining that "'Congress does not readily interfere' with state's 'substantial sovereign powers under our constitutional scheme.'" (citations omitted)).

[358] One way of looking at this case is as a simple application of the federalism canon rather than as imposing a limiting principle requirement on agency interpretations. *See American Farm Bureau Federation*, No. 13-4079, slip op. at 42-48, citing *Gregory v. Ashcroft*, 501 U.S. 452, 461 (1991) (explaining that "'Congress does not readily interfere' with state's 'substantial sovereign powers under our constitutional scheme.'" (citations omitted)).

[359] It is important to note that the TSCER contains two qualifications that are not found in BSER: "technological" and "continuous." While we do not need to resolve what those additions mean, it is logical that the BSER encompasses a broader range of systems than the "TSCER." Put simply, the TSCER sets the minimum scope of the BSER.

This definition provides that the "TSCER" includes "precombustion cleaning or treatment of fuels," which frequently occurs off-site and "beyond the source." These activities had been considered in setting standards of performance under the 1970 CAA Amendments (*i.e.*, as it was initially based on the BSER), however, Congress was explicit that in narrowing the standard to the TSCER, the Administrator would not be precluded from considering "beyond the source" technologies at petroleum refineries or coal preparation plants "whether or not undertaken by the source itself" in setting a standard of performance for fossil fuel-fired EGUs.[360] Indeed, performance standards based on the "combination of coal washing and scrubbing" were upheld by the D.C. Circuit in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). Although section 111(a)(1) was restored to reflect the BSER in 1990, Congress never indicated that the reinstated phrase should be more narrowly construed than the TSCER.

To accept commenters' "limiting principle" would ignore the clear authorization to go "beyond the source" under section 111(a)(7). In other words, commenters would read section 111(a)(7) as authorizing broader authority than section 111(a)(1), despite the added qualifications of "technological" and "continuous." Thus, the principle offered by commenters is not only absent from the terms of section 111(a)(1), it is also inconsistent with section 111 as a whole.

XIX. Development of Organized Markets for ERCs

As noted in section V.A. of the preamble, it is reasonable to expect that organized markets will develop so that NGCC units and RE provides can generate ERCs that can be traded, which will facilitate compliance by affected EGUs.

A recent report by Advanced Energy Economy Institute, "Markets Drive Innovation" (July 2015)[361], supports this view. The following is the Executive Summary of this report, which was based on the EPA's proposed rulemaking.

EXECUTIVE SUMMARY

On June 2, 2014, the Environmental Protection Agency (EPA) proposed the Clean Power Plan (CPP) to implement section 111(d) of the Clean Air Act (CAA).[1] While the proposed rule does not mandate a market-based approach to compliance, ample evidence from previous CAA rules suggests that market-based mechanisms are likely to develop under the CPP, and that these mechanisms will spark an industry response that will make available a wide array of cost-effective compliance options.

Past Rules Show that Market-Based Mechanisms Unleash Industry Response

By setting a regulatory signal and allowing for market-based compliance mechanisms, EPA rules have initiated the development of active and efficient markets in reducing the lead content in gasoline, combatting acid rain, and

[360] Sen. Muskie, Sen. Consideration of H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.
[361] http://info.aee.net/hubfs/PDF/AEEI-Market-Response-Report.pdf?t=1436575590466

controlling regional transport of ozone due to emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). These prior regulatory programs offer strong evidence that industry responds rapidly and effectively to regulatory signals set by EPA when market-based compliance mechanisms are allowed, enabling the development and delivery of a wide array of compliance solutions at low cost.

The successful development of efficient and active markets under these programs is demonstrated by the widespread use of trading by affected entities, the use of credit banking where available, and the lack of volatility in market prices for emission allowances. The development and use of markets for emission allowances under these programs provided affected entities with a range of cost-effective emission reduction measures to choose from. As a result, emissions were reduced more quickly than required, compliance costs were significantly lower than expected, and well-functioning private markets in pollution-reducing technologies evolved rapidly in response to the EPA rules.

The Advanced Energy Industry Is Ready to Respond to Market-Based Mechanisms

There is every reason to believe the same thing will happen under the CPP. The basic structure of the CPP allows and even encourages the development of market-based compliance mechanisms that would facilitate the use of technologies and services that deliver emission reductions. Technologies suitable for CPP compliance include a wide range of advanced energy products and services available in the market now that are particularly well suited to such market-based mechanisms. These include electricity generation technologies like natural gas, wind, solar, hydro, and nuclear power; demand technologies and services like building energy efficiency and demand response; and electricity delivery and management technologies like energy storage. The U.S. market for these and other advanced energy technologies and services was $200 billion in 2014, equal to the pharmaceutical industry.[2] Utilities and power plant operators already engage in a variety of markets to procure advanced energy — from direct purchase or operation of renewable resources, to investment in energy efficiency programs, to trading certificates for the attributes of these resources.

Not surprisingly, a number of stakeholders — ranging from state regulators to utilities to regional grid operators to credit-tracking vendors — have already initiated the process of adapting the existing mechanisms used in these advanced energy markets to support market-based options that facilitate CPP compliance. Given the structure of the proposed rule and the status of current markets, the development of market-based compliance mechanisms is a probable, if not inevitable, outcome.

Market-Based Compliance Will Achieve Goals, Reduce Cost, Spur Economic Growth

The market-readiness of a wide array of compliance measures available to respond to a market signal for emission reductions indicates that compliance under the CPP will likely mirror not only the approach, but also the success of market-based compliance outcomes under prior CAA rulemakings. Robust markets for

advanced energy technologies and services, coupled with existing tracking systems customized to meet CPP requirements, together provide a nearly turnkey solution for state compliance needs, ready to deliver emission reductions as soon as the implementation period begins. In turn, a clear and timely regulatory signal from the CPP will drive further investment and deployment of advanced energy technologies and services, delivering emission reductions while also driving market growth, technology improvement, and associated benefits ranging from grid modernization to job growth.

[1] 79 Federal Register 34830 (June 18, 2014).

[2] Advanced Energy Economy, *Advanced Energy Now: 2015 Market Report* (March 2015), *available at* http://info.aee.net/aen-2015-market-report.

With respect to the development of a market associated with EPA requirements to reduce lead content in gasoline, cited above, *see Small Refiner Lead Phase-down Task Force v. EPA*, 705 F.2d 506 (D.C. Cir. 1983) (upholding standard for lead content in gasoline on the basis of rulemaking record demonstrating that a trading program would develop so that all refiners could meet the standard).

In addition to the examples described above, other examples of emissions trading markets that have developed in response to environmental requirements include the market associated with RGGI and renewable fuels requirements.

XX. Finding of Plan Inadequacy

The EPA invited comment in the proposal for this guideline on whether the Agency should establish a mechanism under section 111(d) similar to the provisions under section 110 that allow EPA to call for plan revisions. EPA has concluded that the Agency should develop provisions in the part 60 framework regulations that allow EPA to call for plan revisions under section 111(d) when a State's plan is not complying with the requirements of this guideline. Under this guideline, States have ten years or more to fully implement measures that achieve compliance with the State's emission rate at affected sources. A lot can happen in ten years. It is possible that design assumptions about the effect of control measures the State incorporates into the plan could prove inaccurate in retrospect and could result over time in the plan not meeting the emissions rate reduction required in the plan. In that case, having a procedural mechanism available under section 111(d) similar to the so-called "SIP call" mechanism in section 110(k)(5) will allow the Agency to initiate a process with the State to correct the plan.

Accordingly, as part of the rulemaking to promulgate the federal plan, EPA will be proposing to amend the framework regulations to include a provision similar to section 110(k)(5) under which EPA may find that a State's 111(d) plan is substantially inadequate to comply with the requirements of the Act and require the State to revise the plan as necessary to correct such inadequacies. The proposal would be that, consistent with section 110(k)(5), EPA would notify the State of any inadequacies and establish a reasonable deadline for the State to submit required plan revisions. That deadline would not exceed 18 months after the date of the notice. EPA would make its finding and notice to the State available to the public. The effect of such a finding would be that either the State submits the program corrections by the date EPA sets in the notice, or, pursuant to section 111(d)(2)(A), the EPA would have the authority to issue a federal plan. In effect, the finding of plan inadequacy would establish a plan submittal deadline

subject to the provisions of section 111(d)(2)(A). Failure to meet that new deadline would trigger EPA's authority to issue a federal plan for the State.

XXI. Relative Stringency of Section 111(d) and 111(b) NGCC Standards

This section contains additional information relevant for section V.B.7. of the preamble, concerning the respective stringency of the section 111(d) rule for existing NGCC units and the section 111(b) rule for reconstructed NGCC units.

As explained in the section 111(b) preamble, the standard for new NGCC units is designed to accommodate a wide range of unit types, including small units and rapid-start units, which are a small part of the expected new NGCC generation capacity. As such, the 111(b) standard (1,000 lb CO_2/MWh gross, which equates to 1,030 lb CO_2/MWh net) will not constrain the emissions of the great majority of expected new NGCC generation capacity, which is expected to consist of larger base load units (with a capacity of 100 MW or greater) that are not intended to cycle frequently. Their initial emissions are expected to be below 800 lb. CO_2/MWh gross, their emissions over ti[362]me may be somewhat higher due to equipment deterioration, and as a result, their PSD permits are expected to include emission limits at approximately the 800 lb. CO_2/MWh gross level. A very small amount of the new NGCC generation is expected to be small units (with a capacity of approximately 25 MW) or rapid-start units. Their initial emissions are expected to be approximately 950 lb. CO_2/MWh gross, their emissions over time are expected to be somewhat higher due to equipment deterioration, and it these units that the standard of 1,000 lb. CO_2/MWh gross is designed to constrain.[363] As a result, the 1,000 lb. CO_2/MWh gross limit applies to all new NGCC units, including the great majority of the expected new capacity consisting of larger, non-rapid start units, even though, as just noted, the great majority of the units are expected to emit at significantly lower emission rates. The section 111(d) standard for existing sources, in contrast, is generally expected to constrain existing NGCC units on average. Moreover, very little of the existing NGCC generation includes small units or, in particular, rapid-start units because the latter are a recently developed technology.

The same is true for the 111(b) standard for reconstructed NGCC units. The average NGCC rate was approximately 850 lb CO2/MWh gross in 2014 and, as a result, most sources are emitting below the section 111(b) standard for reconstructed sources already. Moreover, as the EPA explained in detail in the 111(b) preamble, an owner or operator that undertakes a reconstruction, which is a project that exceeds 50 percent of the capital cost of an entirely new unit, is essentially rebuilding the turbine to operate as if it were new. For these types of projects, an owner or operator will be able to upgrade the efficiency of the combustion turbine and the steam cycle (the HRSG and steam turbine) and match the two systems for maximum performance. For example, owners and operators can upgrade combustors, add triple pressure steam, and add a reheat cycle. After these improvements are made, reconstructed combustion turbines will operate with emission rates comparable to new combustion turbines. In other

[362] Even if the EPA were to adopt a federal plan for a specific state, the federal plan would be replaced by a state plan if

[363] As explained in the 111(b) preamble, any attempt to subcategorize and assign a lower emission limit to larger, non-rapid start NGCC units could cause market distortions.

words, the 1,000 lb. CO_2/MWh standard will constrain only small and rapid-start reconstructed EGUs, not the vast majority of combustion turbines serving base load demand. For these reasons, too, the 111(b) standards for new and reconstructed NGCC units cannot be compared to the 111(d) standards for existing NGCC units.[364]

XXII. Consistency of Rule with *Brown & Williamson* and *UARG* Decisions

Many commenters argued that the EPA's rule is not consistent with the Supreme Court's holdings in *Food & Drug Admin. v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000) and *UARG v. EPA*, 134 S. Ct. 2427 (2014). In *Brown & Williamson*, the Supreme Court struck down an FDA regulation to treat tobacco as a drug. The Court stated that an agency may not exercise its authority "in a manner that is inconsistent with the administrative structure that Congress enacted into law." 529 U.S. at 125. In *UARG*, the Court cited *Brown & Williamson* in holding that the EPA had misinterpreted the statute as requiring the expansion of CAA permitting requirements solely on the basis of GHG emissions alone. The Court said Congress must "speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'" *UARG v. EPA*, 134 S. Ct. 2427, 2444 (2014). The commenters stated that regulations often fall into those impermissible categories when an agency interprets a statute in a way that, in the words of the Court, "would ... bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization." *Id.* at 2432 (citing *Brown & Williamson*, 529 U.S. at 160 (2000)). The commenters stated that the Supreme Court further cautioned that "[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate a 'significant portion of the American economy,' ... we typically greet its announcement with a measure of skepticism." *Id.* at 2,444 (quoting Brown & Williamson, 529 U.S. at 159). Further, "[a]n agency has no power to 'tailor' legislation to bureaucratic policy goals by rewriting unambiguous statutory terms." *UARG*, 134 S. Ct. at 2445.

The agency disagrees with the commenters' interpretation that these cases should be read to foreclose the agency's action in this rule. We explain here why the cases are distinguishable by looking at the facts at issue there compared with the facts here.

First, it is important to place the Court's holdings in the context of the facts at issue in those cases, and in particular, the fact that in both cases, the agencies' interpretation of one part of the relevant statute created a direct conflict with another part of the statute. In *Brown & Williamson*, the Supreme Court struck down an FDA regulation to treat tobacco as a regulated drug, because if this were correct, then cigarettes would be "devices," in which case the relevant "Act would require the agency to ban them." 529 U.S. at 137. The Court found numerous reasons why this conclusion was inconsistent with the text and structure of the relevant law as well as clear expressions of congressional intent. *Id.* at 137-59. Similarly, in *UARG* the Court was faced with a statutory construction that the agency itself admitted "would render the statute 'unrecognizable to the Congress that designed it.'" *UARG*, 134 S. Ct. at 2444 (quoting the EPA's Tailoring Rule preamble at 31555). To avoid that result, the agency was forced to rewrite

[364] The section 111(b) standards for modified and reconstructed steam generation units are generally lower than the emission rates of existing stream generation units, but for the reasons explained earlier, those standards cannot be compared to the section 111(d) standards for existing steam generation units.

"precise numerical thresholds," *id.* at 2445 ("It is hard to imagine a statutory term less ambiguous …."). In rewriting "those numbers," the agency according to the Court went beyond the bounds of its statutory authority. *Id.*

The *UARG* opinion also noted specific untenable administrative and permitting consequences identified by the agency itself. Again pointing to the agency's own doubts, the Court noted, "EPA described the calamitous consequences of interpreting the Act in that way." *Id.* at 2442. In the PSD program alone (and with similarly problematic statistics for title V), permit applications would jump one hundred fold, administrative costs would skyrocket from $12 million to $1.5 billion, and "decade-long delays would cause construction projects to grind to a halt nationwide." *Id.* 2442-43. The Court *agreed* with EPA that it was "beyond reasonable debate that requiring permits for sources based solely on [the statutory thresholds] was "incompatible with the substance of Congress' regulatory scheme." *Id.* at 2443. The Court was particularly concerned about the expansion of permitting authority over thousands or millions of new entities. Indeed, dicta regarding an "enormous and transformative expansion of EPA's regulatory authority" are specifically in this context. *See id.* at 2444. "The power to require permits for the construction and modification of tens of thousands, and the operation of millions, of small sources nationwide falls comfortably within the class of authorizations that we have been reluctant to read into ambiguous statutory text." *Id.*

In rejecting the agency's view that the statute dictated a particular reading, the *UARG* Court affirmed the authority and responsibility of the agency, charged with implementing the Clean Air Act, to deploy its expertise and the exercise of its discretion to fashion workable regulatory frameworks for greenhouse gases. *See id.* at 2441, 2442 (directing the agency to use its discretion and look to "statutory context" in applying the CAA to greenhouse gases).

The nature of the agency's action in this rule is fundamentally different from the agency actions and legal interpretations in *Brown & Williamson* and *UARG*. The EPA explains in section V.B.6 of the preamble why this rule is well within its authority under CAA section 111(d) and (a)(1) and does not represent overreaching. With respect to these cases, perhaps most importantly, the agency's interpretation does not create conflicts with other provisions of the Clean Air Act that would render the statute internally inconsistent or "unrecognizable to the Congress that enacted it." Regarding the specific measures at issue in this action, particularly building blocks 2 and 3, we briefly summarize here why these are consistent with the structure of the CAA, the history of its interpretation, and congressional intent.

The measures in building blocks 2 and 3 have been relied on by the industry for decades to reduce emissions. As noted in section XVI of this Legal Memorandum, least-emissions dispatch has been considered a relatively inexpensive approach to air pollution control since at least 1968. Thus, generation shifts were recognized as means to reduce air pollutants even before the enactment of the 1970 CAAA, and renewable energy (RE) became well established soon after that. Congress relied on generation shifts and RE as part of the basis for Title IV, a provision closely related to section 111. These provisions and the legislative history of Title IV are supportive of interpreting section 111(d) and (a)(1) to be broad enough to include building blocks 2 and 3 because both Title IV and this rulemaking concern the same industry, Title IV was enacted and section 111(a)(1) was revised in the 1990 CAA Amendments, and Title IV and section 111(a)(1) are linked.

With respect to regulatory action, the preamble and Legal Memorandum describe the numerous EPA regulatory actions that are based at least in part on generation shifts and RE.[365] To reiterate some of them: the EPA has relied on generation shifts in adopting a series of rules for EGUs, in particular, the transport rules. There, the EPA noted the importance of regulating EGUs in a holistic manner that takes into account the generation shifting facilitated by the interconnected nature of the electricity grid, and the fact that all EGUs produce an identical product—electricity. *See* Legal Memo Section XV.B, C and D.

Regarding building block 2, SIPs have included RE measures. As the EPA noted in the proposal, SIPs already include RE measures to reduce the need for generation from the more polluting forms of energy generation, such as fossil fuel-fired EGUs. *See* 79 FR at 34887-88; and Legal Memo Section XVII. In addition, the EPA transport rulemakings recognized that EGUs may comply through RE.

Relying on generation shifts and RE to reduce CO_2 emissions is consistent with the integrated nature of this sector, which the industry itself encouraged the agency to consider in designing this rule. And there is widespread agreement within the industry that at a minimum, generation shifts and RE should be allowed as means of compliance.[366] *See* Legal Memo Section VI. Unlike the Court's concern in *UARG*, this rule does not impose federally enforceable regulatory requirements on any entity other than affected EGUs, which are generally already regulated under the Clean Air Act. The agency is not finalizing the portfolio approach. And while the agency is setting minimum criteria for the use of certain emission-credit forms of trading to ensure the validity of the credits, the CAA-enforceable emission standard remains solely on the affected EGUs. Thus, this rule does not have the effect of expanding CAA jurisdiction in a way that Congress would not recognize.

Third, we note that the BSER, as well as the scope of available compliance options the agency is recognizing in the final rule, is fully consistent with current trends in the industry. As the American Public Power Association (APPA) informed the agency, "[S]ubstantial emission reductions from the power sector [] have already occurred and will continue to occur as a result of unit retirements, fuel switching, energy efficiency programs, and increasing use of renewable and other non-emitting or lower emitting energy sources…." *See* Legal Memo Section VI.[367]

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[365] Regardless of whether these regulatory actions relied on generation shifts or RE as the basis for the regulatory requirements or as compliance alternatives, the availability of generation shifts or RE as a means for the EGUs to achieve the emission limits required by those actions indicates that both generation shifts and RE should be considered a "system of emission reduction" under section 111(a)(1).

[366] As noted elsewhere, the "best system of emission reduction … adequately demonstrated" (BSER) is what assures that the emissions performance rates are "achievable" under section 111(a)(1). The fact that some of the affected industry has requested that generation shifts and RE be allowed as compliance methods supports treating those measures as a "system of emission reduction" because the industry recognizes that those measures will facilitate their ability to achieve their emission rates.

[367] For a comprehensive survey of steps taken in each state to promote renewable energy, demand-side energy efficiency measures, and other measures that reduce greenhouse gases, *see*

Thus, industry may comply by continuing to take the same types of actions they have already been taking. In any event, industry will have significant flexibility in choosing its methods of compliance. As discussed in section V.A.6 of the preamble and section VII of the Legal Memorandum, states and sources have choices as to the amount or degree to which they implement the measures in the building blocks and a high degree of flexibility to use other methods.

Accordingly, basing the BSER on BB2 and BB3 does not create a *Brown v. Williamson* or *UARG* problem. The EPA is not asserting "new authority to regulate the economy" – the EPA has authority to regulate CO_2 emissions from the power sector, and the EPA is not regulating anything else. The EPA is basing the control requirements on actions that the power sector has long taken for various purposes, including reducing emissions for compliance with other parts of the CAA (e.g., Title IV, NAAQS SIPs, and the transport rules), and which the EPA has specifically relied on in a series of rulemakings for EGUs.

While it is true that the compliance costs imposed by this rule will have impacts on the industry, that is invariably the case with environmental regulation of any industry. For example, as Sierra Club and Earthjustice noted in their comments, EPA's regulation of hospital, medical, and infectious waste treatment has increased the costs of incineration and, as a practical matter, has caused the closure of incinerators in favor of alternative compliance options,[368] with a decrease from over 2,000 units in the mid-1990s to 57 in 2008.[369] The commenters also argued that outsourcing waste management to commercial waste treatment companies today is the most common compliance option for medical incinerators,[370] and that the availability of waste management measures for compliance has also resulted in a decrease in the percentage of medical waste incinerated,[371] increased use of alternative treatment methods,[372] and thus the

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Laura Jensen, Kelly Nishikawa, & Benjamin Lowenthal, "The State Response to Climate Change: 50 State Survey" in *Global Climate Change and U.S. Law* (Michael B. Gerrard & Jody Freeman eds., 2d ed. 2014), available at http://digitalcommons.pace.edu/lawfaculty/973/ (compilation of state legislation, rules and executive orders that address climate change as of the end of April 2014, including legislation related to energy efficiency and renewable energy).

[368] EPA redeveloped the 1997 emission guideline for these incinerators in response to the D.C. Circuit's concerns about the methodology employed to calculate the MACT floors under Section 129. The agency identified that, under the re-developed standards, autoclaving, commercial medical waste disposal, and hauling of medical waste to municipal waste combustors would likely be used as alternative compliance options. Memorandum from T. Holloway to K. Patel, U.S. EPA, Revised Compliance Costs and Economic Inputs for Existing HMIWI (July 6, 2009), attached as Ex. 5, at 12-13.

[369] Heller & Nourani, Economic Impacts of Revised MACT Standards for Hospital/Medical/Infectious Waste Incinerators, Final Report, RTI Project No. 0209897.002.036 (Oct. 2008), attached as Ex. 6, at 2-16.
[370] Id. at 2-17.
[371] Id. at 2-16.
[372] Id. at 3-3

reduced the utilization of these units.[373] *See also New York v. Reilly*, 969 F.3d 1147, 1153 (D.C. Cir. 1992) (remanding a section 111 rule to the EPA to better explain why a simple ban on combustion of a particular material was not the best demonstrated technology as a technical matter).

XXIII. Severability of State Plan Components

This section provides additional information for section VIII of the preamble.

While each of the state plan components is important to assuring that overall emission reductions are achieved, if legal challenges result in the Court invalidating individual items, this generally would not affect a source's ability to make compliance choices while EPA (and ultimately states) made whatever adjustments were appropriate to address a court decision. These adjustments could be made well before sources are required to meet any reduction in requirements in 2022 (or even later, depending upon the specifics of a state plan). For these reasons, EPA intends that under these circumstances, the remaining state plan requirements would remain in place as much as possible.

XXIV. Compliance Methods for Affected EGUs

This section supplements section V.A., V.D., and V.E. of the preamble by describing ways that affected EGUs can implement building blocks 2 and 3, including obtaining cost recovery.

A. Overview

In this section, we describe in more detail the steps that different types of affected EGUs can take to implement building blocks 2 and 3 in states with rate-based or mass-based emission standards, and we describe environmental compliance cost recovery issues.

The electric power sector is complex and we recognize that there are multiple types of entities that will need to comply with the 111(d) final rule in different regulatory regimes with many ways in which states can design state plans to set emission standards for affected EGUs. Given this diversity, there could be dozens of scenarios through which affected EGUs can comply. Therefore, we cannot describe every potential pathway in which affected EGUs will comply with the standards of performance established for them in their state plans issued pursuant to the 111(d) final rule. The final rule provides states and affected EGUs with flexibility in complying with 111(d) requirements, recognizing that states and affected EGUs are in the best position to know how they can meet the final rule requirements.

Here, we describe scenarios by which affected EGUs can implement building blocks 2 and 3 as part of strategies to achieve their standards of performance, focusing first on states with rate-based emission standards. Our discussion is organized around the market structures under which affected EGUs operate. While large parts of the country continue to operate in vertically integrated states without organized competitive wholesale markets (e.g., much of the West and

[373] Id. at 2-16.

the Southeast), two-thirds of the country's electricity load is now served by an ISO/RTO.[374] While each RTO[375] has unique rules and requirements that participants must follow, there are similarities in market structures that can ease the understanding of how affected EGUs can implement the building blocks. We then consider ways in which affected EGUs within more traditional market structures can implement building blocks 2 and 3. For this purpose, we divide those more traditional market structures into subcategories to account for the different market structures and regulatory schemes outside RTOs. We also consider how affected EGUs in states with mass-based emission standards can achieve their emission performance requirements. Finally, we consider cost recovery issues within each of these market structures identified above.

B. RTO Participants

1. Background

As discussed in more detail in the preamble background section, RTOs are membership-based, independent, non-profit organizations that ensure reliability and operate wholesale electricity markets to optimize supply and demand bids.[376] RTOs also serve as independent transmission system operators to help ensure open access to transmission service. RTOs have many different types of members, including "[i]ndependent generators, transmission companies and load-serving entities, [i]ntegrated utilities that combine generation, transmission and distribution functions, and [o]ther entities such as power marketers and energy traders."[377] RTOs dispatch electricity by inputting "day-ahead and real-time bids from both generators and load-serving entities into complex optimization software, along with other information like unit characteristics."[378] In an RTO, the system operator dispatches units through Security Constrained Economic Dispatch (SCED). SCED has two components – economic operation of generating facilities and assurance that the electric system remains reliable and secure.

As a general matter, RTOs that have coal-fired generation also have NGCC units participating in the market. As we discuss further in the BSER discussion in preamble section V.D., a large percentage of affected steam EGUs also own NGCC units or have affiliates that own NGCC units. Some of these affected steam EGUs and NGCC units owned by the same entity or within the same corporate family may be located in the same RTO. Others may be located in different geographic areas and various markets. For affected steam units that do not own NGCC within the same corporate family, there are available NGCC units either within the same RTO or in other geographic locations that affected steam EGUs can transact with to

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[374] Analysis Group, *Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Market Outcomes*, at 14 (May 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/clean_power_plan_markets_may_2015_final.pdf (stating that ISOs/RTOs "span more than two-thirds of the states, encompass 70 percent of the nation's generating capacity, and serve the electricity needs of two-thirds of the American people.").
[375] In this section, when we refer to RTO, we are including both RTOs and ISOs.
[376] EIA *About 60 % of the U.S. Electrical Supply is Managed by RTOs* (Apr. 4, 2011), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=790.
[377] *Id.*
[378] *Id.*

implement building block 2. As discussed more fully below, affected steam EGUs have multiple opportunities to implement building block 2. Additionally, both affected steam EGUs and NGCC units operating within RTOs also have multiple ways in which they can implement building block 3. Regardless of ownership, affected EGUs in RTOs can implement the building blocks.

2. Building Block 2: Implementation methods

"Changes in the cost of operating different types of power plants will affect their dispatch. In principle under the `normal' economic dispatch arrangements similar to those in power systems everywhere around the country, the grid operator (e.g., the utility for a vertically integrated power system, or the independent system operator in an `organized' wholesale market) schedules plants to operate so as to minimize the overall cost of production on the system."[379] Under SCED, the system operator will dispatch an electric power plant that experiences an increase in its variable costs – e.g., for environmental compliance measures - less than it otherwise would have. Environmental conditions, such as compliance costs or limits on generation, can be factored in with fuel costs to determine when the unit is committed to be available, how the unit can be most efficiently cycled, and at what level the unit is dispatched. For example, existing mass-based market-based pollution control programs require units to hold tradable allowances to authorize their emissions of a regulated pollutant. Such an allowance-holding requirement puts a price on the act of emitting the regulated pollutant, which increases the operating costs of units that emit that pollutant, and thus such units will be dispatched less than they otherwise would without such an allowance-holding requirement. The Regional Greenhouse Gas Initiative (RGGI) is an example of a program that has this effect.[380]

a. Purchase of Emission Rate Credits (ERCs)[381]

Our discussion in this section describes ways in which an affected steam EGU could purchase ERCs from an NGCC generator that has generated them by increasing the NGCC unit's generation and acquiring CO_2-reducing effects in the form of a credit. The ERC would represent the emissions-reducing benefit of the investment and could be used by the affected steam EGU

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[379] Analysis Group, *EPA's Clean Power Plan: State Plans and Consumer Impacts*, at 12 (July 2014), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_epa_clean_power_plan_report.pdf.

[380] RGGI "is the first market-based regulatory program in the United States to reduce greenhouse gas emissions. RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions from the power sector." RGGI, *Regional Greenhouse Gas Initiative: an Initiative of the Northeast and Mid-Atlantic States of the U.S.*, *available at* http://www.rggi.org/.

[381] "The EPA defines an ERC in the emission guidelines as a tradable compliance instrument that represents a zero-emission MWh (for the purposes of meeting the emission guidelines) from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA section 111(d)." *See* Preamble Section VIII.K.2.

to reduce its emission rate.[382] Many affected steam EGUs will likely implement building block 2 by purchasing ERCs in trading markets that develop to facilitate affected EGU's compliance with standards of performance established in state plans pursuant to the 111(d) final rule. Under an emissions rate-based ERC system, NGCC units may generate ERCs for sale by increasing their generation, as described in section VIII of the preamble.

[383] Under an emissions rate-based compliance paradigm, affected EGUs with emissions rates higher than their standard of performance can acquire these ERCs and average them into their emission rate computations for compliance purposes. This will result in an increase in the running costs of these higher emitting resources, potentially decreasing the amount that these resources are dispatched in the SCED process. We discuss ERCs in greater detail below in connection with RE.

b. Bilateral agreements

Affected steam EGUs in RTOs have other methods to implement building block 2. For example, there are mechanisms by which an affected steam EGU can increase an NGCC unit's generation and claim a credit to reduce its steam rate bilaterally. Under such a mechanism, the increase in NGCC generation does not need to occur within the same RTO or even the same kind of market structure. For purposes of our discussion here, we describe a scenario where both generation units are in the same RTO.

A first step in our analysis is whether the affected steam EGU owns, jointly owns, or is otherwise affiliated with an existing NGCC unit. A large percentage of affected steam EGUs already own or are affiliated with NGCC generation. As discussed further in preamble section V.D., an analysis of generation data from steam and NGCC units in 2012 shows that 77 percent of steam generation was produced by an EGU that owned, or that had an affiliate that owned, NGCC generation. An entity that owns both an affected steam EGU and NGCC, or is affiliated with NGCC, can bid the NGCC unit into the RTO in a way that can be expected to increase the amount that it is dispatched, and, under those circumstances, generate ERCs. The entity could then either sell the NGCC-generated ERCs to another affected steam EGU or use those ERCs to meet the rate-based requirement of its own affected steam EGU. The entity would then be able utilize the ERCs generated by the NGCC unit that it owns or is affiliated with when it bids the affected steam EGU into the RTO. Under this example, the affiliated NGCC unit which produced the ERC could transfer the ERC to the affected steam EGU through an internal accounting method, which valued the ERC. The affected steam EGU could include those costs as part of its cost-based offer, which would increase its offer, potentially decreasing the amount that it is dispatched. Finally, we note that environmental emission constraints will likely increase the

[382] For a more comprehensive discussion of ERCs, please see preamble sections V.A.5. and section VIII.
[383] *See generally* PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal*, at 85 (March 2, 2015), *available at* http://www.pjm.com/~/media/4CDA71CBEC864593BC11E7F81241E019.ashx.

cost of affected steam EGU bids throughout the RTO, causing the system operator to dispatch less steam generation and more NGCC through the SCED process.

If an affected steam EGU does not own or control an NGCC unit, another avenue it could explore is contracting with an NGCC unit to purchase the energy and/or environmental attributes from the NGCC unit. The electricity sector is highly transaction-driven with many examples to draw upon over decades of experience of financial and physical contracts that serve multiple needs.[384] Sophisticated contracting parties could utilize examples such as power purchase agreements as models for how to undertake these kinds of contracts.[385] For example, the affected steam EGU might explore this kind of contract if it already has a long-term power supply contract in place that it needs to meet, but cannot because of emissions restrictions. The steam unit might contract with the NGCC unit as a partial replacement source. The affected steam EGU's ability to use this option will depend upon the terms of the long-term contract.[386] Additionally, the affected steam EGU could also bilaterally contract with an unaffiliated NGCC unit to purchase ERCs that the NGCC unit had generated.

c. Reduced generation

An affected steam generator subject to an emission rate limit can decrease the number of ERCs that it needs to obtain by reducing its generation.[387] Generally speaking, there are two ways in which an affected steam EGU can reduce its generation. First, it can take a permit restriction on the amount of hours that it generates. The affected steam EGU can also represent the cost of additional ERCs that it would need to purchase due to incremental generation as an additional variable cost that increases the total variable cost considered when dispatch decisions

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[384] "A bilateral contract in an electricity market is an agreement between a willing buyer and a willing seller to exchange electricity, rights to generating capacity, or a related product under mutually agreeable terms for a specified period of time." Synapse Energy Economics, Inc., *Bilateral Contracting in Deregulated Electricity Markets: A Report to the American Public Power Association*, at 1 (April 18, 2008), *available at* http://synapse-energy.com/sites/default/files/SynapseReport.2008-04.APPA_.Bilateral-Contracting-in-Deregulated-Electricity-Markets.07-055.pdf.

[385] There are multiple types of contracts with different provisions that entities use in the electricity sector to meet energy needs. For example, a contract for energy and/or capacity could specify the generating unit or it could make the contract non-generating unit specific or multiple unit specific. David Elliott, *Presentation on Bilateral Contracts for Power*, 5-6 (November 5, 2012), *available at* http://www.naruc.org/international/Documents/Elliott_Power%20Agreements2_Mon_Nov%205_3-45pm_eng2.pdf.

[386] For example, the contract could have a force majeure provision that would allow it to suspend part of its performance because of environmental limitations. Additionally, the contract could be non-generating unit specific.

[387] Note that this would not reduce overall generation because other generators would increase their generation.

are made for the unit. This increase in cost has the potential to decrease the amount that the affected EGU is dispatched, thereby decreasing the ERCs that it would need to purchase.

3. Building Block 3 in an RTO: Implementation methods

a. Purchase of ERCs

The ability of affected EGUs to obtain incremental RE to reduce CO_2 emissions is well-demonstrated. Affected EGUs can implement this building block through direct ownership, bilateral contracts, or procurement of the environmental attributes[388] associated with RE generation. Affected EGUs can implement building block 3 by utilizing ERCs in a similar way to how they would utilize ERCs under building block 2. Affected EGUs can buy ERCs, and average them into their effective rates to achieve the required emission rates. There are well-established mechanisms which RE generators can use to generate ERCs and demonstrate the environmental attributes of those ERCs, and which affected EGUs can use to acquire the ERCs.

For example, multiple RTOs already have systems that assist market participants to comply with environmental requirements that can be used as a model for states and affected EGUs implementing building block 3. Currently, there are 10 generation attribute tracking systems covering the U.S. and Canada.[389] A number of these tracking systems are in the same footprint as an RTO. These include the Texas Renewable Energy Credit System, the New England Power Pool Generation Information System (NEPOOL GIS), New York Generation Attribute and Tracking System (NYGATS), PJM Generation Attribute and Tracking System (GATS), and the Midwest Renewable Energy Tracking System (M-RETS).[390] The Western Renewable Energy Generation Information System (WREGIS) tracks renewable energy generation across the Western Electricity Coordinating Council (WECC).[391] NEPOOL GIS is NEPOOL's RE registry and tracking system for electricity generation.[392] "For each megawatt-hour of electricity generated by an individual unit, a certificate is assigned that records the attributes of that power."[393] Electricity suppliers utilize these certificates to (1) "[d]ifferentiate their products for consumers"; (2) "[p]rovide the information required on energy disclosure labels"; and (3) "[c]omply with state and regional Renewable Portfolio Standards (RPS) and emissions performance standards".[394]

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[388] PJM Environmental Information Services (EIS) defines environmental attributes "as any credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly [a]ttributable to the generation from the [g]enerating [u]nit(s)." PJM EIS, *Generating Attribute Tracking System (GATS) Operating Rules*, at 11 (May 2014), *available at* http://www.pjm-eis.com/~/media/pjm-eis/documents/gats-operating-rules.ashx.
[389] Regulatory Assistance Project, *F*, at 5 (May 2015), *available at* raponlin.org.
[390] *Id.*
[391] *Id.*
[392] ISO New England, *Generation Information System*, *available at* http://www.iso-ne.com/markets-operations/settlements/gis.
[393] *Id.*
[394] *Id.*

PJM also has tools in place to help entities meet state environmental requirements. PJM has a subsidiary that facilitates the reporting and tracking of emissions data and renewable energy credits (RECs). PJM Environmental Information Services (EIS) administers this program through GATS, which has a diversity of subscriber classes and is designed to meet the needs of those participating in the REC market. According to PJM EIS, "Due to the wide-spanning nature of the system's audience, the system itself needs to be wide-spanning. To small renewable generation owners, such as those with solar PV systems, the GATS allows users to report generation data and collect credits. To larger systems, electric distribution companies (EDCs), and electric generation suppliers (EGS') the GATS allows the [users'] generation data to meet the various information disclosure requirements imposed by state entities. Additionally, the GATS provides users a bank account of sorts for those subscribers who need to demonstrate REC compliance. Through generation data, the GATS creates RECs, which are electronic certificates composed of various data. RECs identify pedigree characteristics of the particular generator such as: location; the emissions output of the generator; the fuel the generator uses to produce electricity; and, the date the generator went online, also known as vintage."[395] Generation owners can sell these certificates to an interested buyer. "Buyers can vary from electric utilities to middle-people, such as brokers or aggregators, to environmental firms or to non-industry companies looking to neutralize their carbon footprint. For state agencies the GATS provides an effective way to implement policies and regulations. The GATS allows regulators access to centralized on-demand reports about RECs, and fuel mix and emissions disclosure. Reports are always current, as they draw directly from the GATS database, and provide regulators a means to monitor, verify and document compliance."[396]

These generation tracking systems can serve as a model for how the characteristics of electric generation can be recorded and tracked in states and regions throughout the country, making implementation of both building blocks 2 and 3 easier for affected EGUs to achieve and regulators to track. Moreover, while these systems generally have been used to track the environmental attributes of renewable generation, they could similarly be utilized to track other forms of generation, including natural gas generation.

b. Direct investment in new RE

Additionally, affected EGUs can directly invest in new RE thereby claiming the credits from the new RE. There are many affected EGUs that already have developed new RE generation themselves or have contracted with third-parties that have developed RE, giving those affected EGUs experience in how to develop those resources. Some of the largest owners of affected EGUs also own RE. For example, NRG Energy, Inc. owns more than 3,000 megawatts of RE capacity, over 20 percent of which (nearly 800 megawatts) is solar, and almost 80 percent of which (over 2,500 megawatts) is wind.[397]

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[395] PJM Environmental Information Services, *About GATS*, *available at* http://www.pjm-eis.com/getting-started/about-GATS.aspx.
[396] *Id.*
[397] For a more comprehensive discussion of this issue, please see preamble section V.E.

For those affected EGUs that have not invested in RE in the past, many examples exist in the electricity industry for how multiple types of affected EGUs could develop new RE resources. For example, the National Renewable Energy Laboratory (NREL) drafted a guide drawing on these experiences that details the ways in which state and local governments can contract with third-parties to develop and finance renewable energy projects.[398] NREL takes the reader step-by-step through how state and local governments can (1) identify potential RE development areas; (2) issue a request for proposal (RFP) to competitively select a developer; (3) develop contracts; (4) go through the permitting and rebate process; and (5) complete project design, procurement, construction, and commissioning.[399] The NREL paper provides an excellent overview of how municipalities, electric cooperatives, and other entities that own affected EGUs can contract with third-parties to develop RE resources.

c. Reduced generation

As discussed above, similar to an affected steam generator in building block 2, an affected EGU under building block 3 can also decrease the number of ERCs that it needs to obtain by reducing its generation.[400]

C. Non-RTO Participants

1. Background

While RTOs serve more than two-thirds of the nation's load, there are many different traditional market structures outside of RTOs in which affected EGUs participate. "Markets vary around the United States by market type – traditional or RTO – generation types, customer use, climate, fuel costs, political and regulatory conditions, and other factors."[401] "Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers."[402] As a general matter, wholesale physical power trading outside of RTOs occurs through bilateral transactions.[403] Vertically integrated utilities, which own transmission, distribution, and generation assets, utilize a variety of means to meet load,

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[398] NREL, *Power Purchase Agreement Checklist for State and Local Governments*, *available at* http://www.nrel.gov/docs/fy10osti/46668.pdf.
[399] *Id.* at 1.
[400] Note that this would not reduce overall generation because other generators would increase their generation.
[401] FERC, *Energy Primer: A Handbook of Energy Market Basics*, at 66 (July 2015), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[402] *Id.* at 58. "Utilities in traditional regions have the following responsibilities: [1] Generating or obtaining the power needed to serve customers (this varies by state) [2] Ensuring the reliability of its transmission grid [3] Balancing the supply and demand instantaneously [4] Dispatching its system resources as economically as possible [5] Coordinating system dispatch with neighboring balancing authorities [6] Planning for transmission requirements within the utility's footprint [7] Coordinating its system development with neighboring systems". *Id.*
[403] *Id.*

including "a combination of owned resources, contract resources, and short-term purchases and sales to meet their customer demands, and a combination of their own transmission lines and lines owned by others to move power from where it is produced to the communities they serve."[404] In states with cost-of-service regulation of vertically-integrated utilities, the utilities themselves are often also the balancing authorities who determine unit dispatch in a cost-minimizing fashion (seeking the lowest marginal cost). They can also arrange to buy and sell power with other balancing authorities. The methodology that individual affected EGUs outside of RTOs will utilize to implement building blocks 2 and 3 depends upon the affected EGU's size, available resource mix, and the historical relationships that it has developed for meeting electricity demand.

Given the diversity of entities in the electricity sector, it is not possible to fully describe the unique situation of each and every affected EGU. However, there are some useful distinctions that can be helpful in understanding potential ways to implement the building blocks for entities outside of RTOs. First, there are large utilities or groups of utilities that operate balancing authorities and have a diverse resource mix to meet electricity demand. Second, there are smaller entities, such as some municipalities, electric cooperatives and other public power entities, which may not have a diverse resource mix but can still implement building blocks 2 and 3. Finally, we note that in some areas in the West there are increasing opportunities for entities to participate in the Energy Imbalance Market to meet system needs and diversify resources.[405]

2. Building Block 2

Outside of RTOs, a large utility or groups of utilities may be responsible for balancing electrical supply and load over a wider geographic area. Some of these entities are very large with multiple utilities or operating companies signing an agreement or agreements establishing the terms and conditions for members. These entities will often have a diverse resource mix with both affected steam EGUs and NGCC units that need to comply with standards of performance in state plans developed pursuant to the 111(d) final rule. As noted above, affected steam EGUs could purchase ERCs in order to implement building block 2 and achieve the specified emission rate. Additionally, similar to the methods utilized in RTOs, an affected steam EGU could utilize an ERC generated by an NGCC unit that it owns or is affiliated with to meet its emission-rate limits. The NGCC unit could either sell those ERCs to another affected steam EGU or utilize those ERCs to meet the rate-based requirement of its own affected steam EGU. Further, we note that power markets in these areas are largely bilateral markets, providing affected steam EGUs with opportunities to bilaterally contract to purchase energy and/or environmental attributes from

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[404] Regulatory Assistance Project, *Electricity Regulation in the US: A Guide*, at 10 (March 2011), *available at* raponlin.org.

[405] "As the only real-time energy market in the Western U.S., advanced ISO market systems automatically balance supply and demand for electricity every fifteen minutes, dispatching the least-cost resources every five minutes. This service is available to other grids operating in the West as a way to share reserves and integrate renewable resources across a larger geographic region--reliably and efficiently." CAISO, *Energy Imbalance Market Overview, available at* https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

available NGCC units. In addition, a large federal entity such as the Tennessee Valley Authority (TVA) with a diverse mix of generation resources could utilize similar methods to those utilized by a large utility or group of utilities to implement building block 2.[406]

We note that there are smaller balancing authorities that are not in RTOs or areas with large, diversified utilities. These balancing authorities can include municipalities,[407] electric cooperatives, and other public power. Many of these entities own a small amount of generation and may contract with others in order to obtain the generation they need to meet load. One way in which these entities could meet building block 2 is by buying ERCs. Moreover, many of these entities also have a history of bilaterally contracting to meet load. They could also implement building block 2 by bilaterally contracting for NGCC while decreasing their steam generation. Additionally, in some cases, these entities may own both steam EGUs and NGCC. In those instances, they could reduce their coal dispatch and increase natural gas dispatch. Some electric cooperatives and/or municipalities belong to a generation and transmission cooperative that supplies wholesale electricity to its members, providing additional opportunities for electric cooperatives to implement both building blocks 2 and 3.[408]

3. Building Block 3

Similar to building block 2, affected EGUs in large utilities or groups of utilities can implement building block 3 by buying ERCs. These entities could also acquire an ownership interest in new RE. Many entities already have experience with developing RE resources and can similarly invest in new RE either by developing the RE itself, jointly investing in RE with another entity, or contracting with a third-party to develop RE resources.

This is also true for other entities outside RTOs and large utilities or groups of utilities. Municipals, electric cooperatives, and other public power entities can purchase ERCs from RE resources. These entities also have a history of contracting with outside sources to meet their electricity supply needs and can use this as a model for how to contract for RE. Public power sources may wish to develop their own RE resources to implement building block 3. The NREL

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[406] TVA is the largest public power provider in the U.S. Congress founded TVA in 1933 as a U.S. government corporation "to address a wide range of environmental, economic, and technological issues, including the delivery of low-cost electricity and the management of natural resources." Tennessee Valley Authority, *From the New Deal to a New Century*, *available at* http://www.tva.com/abouttva/history.htm. TVA recently published its 2015 Integrated Resource Plan enumerating how TVA will meet the long-term energy needs of the region. Tennessee Valley Authority, *2015 Integrated Resource Plan* (2015), *available at* http://www.tva.com/environment/reports/irp/index.htm.

[407] In some states, several municipal utilities will form a public utility district (PUD) run by groups of cities or a county. Bob Shively and John Ferrare, *Understanding Today's Electricity Business*, at 92 (Enerdynamics Corp. 2012).

[408] For example, Deseret Power is a regional generation and transmission cooperative, which supplies wholesale electricity to its members and other bulk energy customers in Arizona, Colorado, Nevada, Utah, and Wyoming. Deseret Power Electric Cooperative, *Power to Succeed, Now and in the Future*, *available at* http://www.deseretgt.com/profile/profile.php.

paper provides an excellent overview of how municipalities, electric cooperatives, and other entities that own affected EGUs can contract with third-parties to develop RE resources.[409]

D. Implementing the Building Blocks in Mass-based States

Mass-based state plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. In mass-based states, affected EGUs can implement building blocks 2 and 3 by reducing their generation or purchasing allowances. Compliance in mass-based states is determined through a comparison of the affected EGU's monitored mass emissions to a mass-based emission limit. The price of allowances associated with CO_2 emissions will generally be reflected in all units' variable costs as used to make dispatch decisions. Because this added variable cost of CO_2 allowances will be higher for units with higher CO_2 emission rates, when affected EGUs reduce their generation as a strategy for facilitating compliance with their standards of performance, the generation reduced at affected EGUs with higher emission rates will tend to be replaced with increased generation from EGUs with lower CO_2 emission rates whose variable costs will be relatively more competitive because of their lesser CO_2 allowance costs.

E. Cost Recovery

Commenters have raised concerns about cost recovery issues with regard to 111(d) compliance costs. As noted above, RTOs have many different types of market participants. In an RTO, entities such as independent power producers (IPPs) bid into the energy market to recover their costs, including environmental compliance costs. "Markets will clear in a least-cost manner based on operational practices and will send appropriate short-term price signals based on the marginal cost of production."[410] IPPs may also recover their costs through long-term power purchase agreements or other bilateral contracts. Cost recovery for an IPP that sells its power through a bilateral contract will be dependent upon contract mechanisms that allow it to pass through environmental compliance and other regulatory costs. In contrast to IPPs, entities that are operating under cost-of-service regulation obtain cost recovery through state Public Utility Commissions (PUCs) or other authorities with jurisdiction over their rates. "In states where electric utilities own affected power plants, such costs will tend to be passed along to those utility's consumers through regulated rates as a pass-through of a variable expense, or as recovery of and a return on compliance capital investments."[411] The municipal electric utilities, cooperatives, and federal authorities "have rates based on costs pursuant to the decisions of

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[409] NREL, *Power Purchase Agreement Checklist for State and Local Governments, available at* http://www.nrel.gov/docs/fy10osti/46668.pdf.
[410] FERC, *Staff Analysis of Uplift in RTO and ISO Markets*, (August 2014), *available at* http://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.
[411] Analysis Group, *EPA's Clean Power Plan: State Plans and Consumer Impacts*, at 11 (July 2014), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_epa_clean_power_plan_report.pdf.

elected or appointed boards (and in some states, by PUCs)."[412] "Typically, state regulators in states that own power plants determine whether large capital investments at those plants are prudent, used and useful, and appropriate to be included in `just and reasonable' rates charged to customers."[413] In some instances, utilities obtain preapproval of expenditures for costs of environmental compliance. For example, "under Ohio law, under an automatic rider, utilities are able to recover costs of environmental compliance, including `the cost of emission allowances; and the cost of federally mandated carbon or energy taxes…' and a `reasonable allowance for construction work in progress … for an environmental expenditure for any electric generating facility of the electric distribution utility….'"[414]

XXV. System of Emission Reduction as a Set of Measures

In section V.A. and V.B. of the preamble, we discuss the definition of the section 111(a)(1) term, "best system of emission reduction … adequately demonstrated, including a discussion of the term, "system of emission reduction." In our proposal, we defined "system of emission reduction" as, in part, a "set of things …." Some commenters argued that building block 1 and building block 2, were not systems of emission reduction because they were not sets of things or actions.

We disagree with these comments. Each of the examples cited by the commenters consists of a multi-step set of actions that yields emission reductions. For building block 1, the purchase, installation and operation of more efficient equipment could be a set of actions that results in emission reduction and that is similar to the purchase, installation, and operation of add-on pollution controls. The same is true for the undertaking of more efficient operational actions. Similarly, each of the several methods that affected EGUs have to increase generation of existing NGCC units, described in the preamble, coupled with the resulting decreases in steam generation, constitute a set of actions that results in emission reduction

XXVI. Subcategorization

This section responds to various comments concerning the EPA's approach to subcategorization.

In this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different

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[412] Analysis Group, *Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Market Outcomes*, at 5 (May 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/clean_power_plan_markets_may_2015_final.pdf.
[413] *Id.* at 5 n.4.
[414] Regulatory Assistance Project, *Incorporating Environmental Costs in Electric Rates Working to Ensure Affordable Compliance with Public Health and Environmental Regulations*, at 17 (2011) (citing Ohio Revised Code, Section 4928.143(B)(2)(a)and (b)), *available at* raponlin.org.

types of steam EGUs or combustion turbines. As we discuss below, this approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category, and which grant the EPA discretion whether to subcategorize the sources for purposes of determining the BSER.

Each affected EGU can achieve the performance rate by implementing the BSER, specifically, by taking a range of actions –- some of which depend on features of the section 111(d) plan chosen by the state, such as the choice of rate-based or mass-based standards of performance and the choice of whether and how to permit emissions trading -- including investment in the building blocks, replaced or reduced generation, and purchase of emission credits or allowances. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected EGUs, including investment in demand-side energy efficiency measures. Such compliance options may also indirectly help affected EGUs achieve compliance under a mass-based plan.

Our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates and can do so at a reasonable cost using the approaches we have identified as the BSER as well as other available measures. While oil- and gas-fired steam EGUs have lower CO_2 emission rates than coal-fired steam EGUs, oil- and gas-fired steam EGUs represent only a small fraction of the total generation and total CO_2 emissions of steam EGUs overall. These EGUs are not disadvantaged by being placed in a subcategory whose performance rate is established based predominantly on the emissions performance of coal-fired steam EGUs with higher CO_2 emission rates.

We have also exercised our discretion not to subcategorize by the Interconnection regions used in the analysis to develop the nationwide CO_2 emission performance rates, as discussed in section V.A.3.f.

Likewise, although some commenters requested that we subcategorize by ownership in order to establish less stringent emission guidelines for affected EGUs owned by municipal and cooperative utilities, we decline to do so. Traditionally, our subcategorization decisions under section 111 have been based on consideration of physical and operational characteristics, now ownership characteristics. As described in sections V.A.4. and V.A.5., all types of affected EGUs, regardless of ownership, have means for accessing the building blocks and capable of achieving the emission limitations that reflect the BSER.

Of course, a state retains great flexibility in assigning standards of performance to its affected EGUs and can impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below. This rule does not prevent a state from exercising that flexibility with

consideration to the ownership characteristics of its affected EGUs, if the state is persuaded that treating its EGUs differently on that basis is appropriate.

XXVII. Additional Reliability Studies

This section notes additional studies that support the EPA's conclusion that this rulemaking will not jeopardize reliability.

Trieu Mai, Debra Sandor; Ryan Wiser; Thomas Schneider, NREL, "Renewable Electricity Futures Study (January 2012)

GE Energy Consulting, "Minnesota Renewable Energy Integration and Transmission Study; Final Report" (October 31, 2014)

GE Energy Consulting, "Integration of Renewable Resources," (August 2010)

Analysis Group

- April 2015: Ensuring Electric Grid Reliability under the CPP (a rebuttal to some of the critical comments filed with FERC this spring (25 pages or so))
- March 2015: Electric System Reliability and EPA's Clean Power Plan – the Case of PJM (like the one re: MISO)
- May 2014: Greenhouse Gas Emission Reductions from Existing Power Plants: Options to Ensure Electric System Reliability

AEE Institute, NERC's Clean Power Plan Phase I Reliability Assessment – A Critique (May 2015)

Regulatory Assistance Project, "Reliability Standards Safety Valve and the State Clean Power Plan Compliance Obligation" (April 2015)

XXVIII. Potential for emission reductions from non-BSER measures

Section V.A of the Preamble contains a discussion of the use of non-BSER measures to achieve standards of performance. As explained in that section, these technologies are potentially available for use by affected EGUs, depending on the design of state plans, under the guidelines. Non-BSER measures either reduce the amount of CO_2 emitted per MWh of generation from the set of affected EGUs or reduce the amount of generation, and therefore associated CO_2 emissions, from the set of affected EGUs. This section briefly discusses these options and summarizes information the agency relied on in determining that the availability of such options provides additional flexibility and potential cost savings to the individual affected EGUs and the source category to achieve emission reductions consistent with application of the BSER.

Demand-side energy efficiency (DS-EE) is foremost among options that are available, and the potential for reduction in emissions from DS-EE is substantial. For this reason, the

EPA's regulatory impact analysis for the final rule includes a representation of DS-EE compliance potential because energy efficiency is a highly cost-effective means for reducing CO_2 from the power sector, and it is reasonable to assume that a regulatory requirement to reduce CO_2 emissions will motivate parties to pursue all highly cost-effective means for making emission reductions accordingly, regardless of what particular emission reduction measures were assumed in determining the level of that regulatory requirement. The EPA has included in our illustrative plan scenarios (both rate- and mass-based) a level of demand reduction that could be achieved, and the associated costs incurred, through implementation of demand-side energy efficiency measures. For illustration, we estimated the potential for net cumulative demand reduction of 23,150 gigawatt-hours (GWh) in 2020. By 2030, that number climbs to 327,092 gigawatt-hours (GWh), representing a 7.83 percentage reduction from business-as-usual sales. *See* Table 3-2 in the DS-EE TSD. *See also* RIA, section 3.7.1. In Chapter 5 of the DS-EE TSD, we discuss EE strategies that go beyond ratepayer-funded EE programs, of which there are many. These include building energy codes, state appliance standards, energy service performance contracting, and other coordinated efforts by utilities to manage and improve delivery of real and reactive power (referred to as "volt/VAR optimization"). By way of illustration, total savings from state appliance standards alone could be as high as 212 terrawatt-hours (TWh) in electricity savings in 2025. *See* DS-EE TSD, section 5.2.4, Table 7.

The agency also believes other non-BSER measures in addition to DS-EE will be widely available to the industry. The agency discussed these in the proposal, see 79 FR 34923-25. One recent report confirms the agency's view in the proposal, confirmed and reflected in the final rule, that non-BSER measures can potentially play a significant role for many sources. The National Association of Clean Air Agencies (NACAA) report, "Implementing EPA's Clean Power Plan: A Menu of Options" (May 2015), identifies twenty five approaches to GHG reduction in the electric sector, provides a detailed description of compliance methods for each, and, in many cases, provides information as to the amount of emission reductions available through these approaches .[415]

Non-BSER measures NACAA identifies include, among others: implementing CHP; improving coal quality; optimizing grid operations; pursuing CCS; fuel switching; reducing losses in transmission and distribution; increasing clean energy procurement requirements; encouraging clean distributed generation; and revising transmission planning, among others. *See id.* at Intro-4-5. Some of these measures are recognized as under-utilized. For example, CHP accounts for 8 percent of U.S. generating capacity but could be increased to 20 percent, and could reduce CO_2 emissions by 800 million metric tons per year by 2030. *See id.* at 2-1. According to the NACAA report, use of coal washing strategies before combustion can increase plant efficiency, leading to a 2 to 3 percent decrease in CO_2 emissions. *See id.* at 4-3.

It should be noted that in some cases, different parts of the electric sector can be expected to take advantage of different approaches. For example, the NACAA report acknowledges that fuel-switching may be feasible at some plants (e.g., where they may be already designed to co-fire alternative fuels), but prohibitively costly at others. *Id.* at 9-1. The key point is that there are

[415] *See* http://www.4cleanair.org/NACAA_Menu_of_Options.

multiple non-BSER strategies available, some of which may work at some facilities or in one region, and others which may work elsewhere.

The report also notes that grid optimization efforts (e.g., creating a "smart grid" and/or requiring power factor management) can reduce excessive electricity losses during transmission from peaks of around 20 percent to a more typical six or seven percent. *Id.* at 5-2, 5-3. Finally, by way of illustration, distributed generation, such as rooftop solar photovoltaic systems are becoming increasingly affordable and cost competitive. In six years the amount of installed distributed PV has tripled to 3 gigawatts (GW) and the module costs have dropped from about $4 per watt to about $1 per watt. *Id.* 17-1. The NACAA report anticipates considerable growth in distributed generation, and with grid modernization, the GHG-reducing potential of clean distributed generation will increase over time.

While the EPA does not specifically endorse the facts and statistics presented by NACAA in this report, this report confirms the broad scope of non-BSER measures to reduce emissions, and confirms that significant amounts of emissions can be reduced though these measures. Thus, these measures enhance flexibility by both sources and states, potentially lower the costs of compliance with the final rule, and safeguard the ability of affected EGUs to comply with the emission limits of this rule.

XXIX. Amount of Emission Reductions in First Years of Interim Period

In section V.B.7. of the preamble, the EPA discusses the relative stringency of the section 111(b) and 111(d) standards. In that section, the EPA notes that under this rulemaking, all states can meet their interim state goals by 2029 even if they do not require any emission reductions from their fossil steam EGUs or NGCC units in 2022. In fact, most of the states can also meet their interim state goals by 2029 even if they do not require any emission reductions from their affected EGUs in 2023 either. Moreover, all states can achieve their interim emission performance rates for NGCC units by 2029 even if they do not require any emission reductions from their NGCC units until, at the earliest, 2024.

In making these calculations, the EPA relied on the data available in Appendix 3 and Appendix 5 of the CO2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule. EPA assessed what would happen if the adjusted 2012 baseline emission rate for states remained in place through 2022, and 2023, and assessed what would happen if the 2012 baseline emission rate for NGCC units, by itself, remained in place for those years. EPA determined that states could continue to operate at this baseline emission rate level in 2022 and not make any reductions until after 2022, and still comply with its interim state emission rate goal by meeting its final state goal (but not exceeding its final state goal) prior to 2030. In other words, states have the flexibility not to require any emission reductions on the front end of the compliance period, and more on the back end and still comply with the interim rate (again, without reducing the emission rate below the 2030 goal). Moreover, EPA determined that the NGCC fleet in states could go beyond 2023 without having to make any CO_2 emission reductions provided the state would meet (and not exceed) its final goal prior to 2030. The referenced TSD and Appendix are available in the docket for this rulemaking.