Comments of Clean Air Task Force on the Clean Power Plan ("CPP") – Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014); *and* Notice of Data Availability in Support of Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 64,543 (Oct. 30, 2014); *and* Technical Support Document: Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents, U.S. EPA, Office of Air and Radiation (Availability Noticed: 79 Fed. Reg. 67,406 (Nov. 13, 2014)).

Clean Air Task Force ("CATF") respectfully submits these comments on the proposed U.S. Environmental Protection Agency ("EPA" or "Agency") Clean Power Plan ("CPP") carbon pollution emission standards of performance and guidelines for existing electric utility generating units ("EGUs"), and the Notice of Data Availability ("NODA") and Technical Support Documents ("TSDs") in support of the CPP. Founded in 1996, CATF seeks to help safeguard against the worst impacts of climate change by working to catalyze the rapid global development and deployment of low carbon energy and other climate-protecting technologies, through research and analysis and public advocacy leadership. We have previously submitted comments to the Agency on the January 2014 proposed new source carbon pollution performance standards for electric utility generating units, 79 Fed. Reg. 1,430 (Jan. 8, 2014) and EPA's proposed modified and reconstructed source carbon dioxide ("CO_2") performance standards for this industry, 79 Fed. Reg. 34,960 (June 18, 2014).[1] CATF congratulates EPA on proposing this suite of carbon pollution standards for EGUs, and offers our views and recommendations on this most important proposal.

I. Introduction and summary.

a. These (or even more stringent) standards are essential if the United States is to reach its stated climate pollution reduction objectives.

As the President recognized in his historic 2013 Climate Action Plan and accompanying memorandum on carbon pollution standards for the electricity generation sector,[2] and more

[1] Comments submitted by Clean Air Task Force ("CATF"), Docket No. EPA-HQ-OAR-2013-0495-11005 (May 12,

[2] Executive Office of the President, "The President's Climate Action Plan," at 6 (June 2013) available at: http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf [hereinafter "Climate Action Plan"]; *see also* Presidential Memorandum, "Power Sector Carbon Pollution Standards," (June 25, 2013), *available at*: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards. These actions followed the President's 2009 pledge that the U.S. would decrease its GHG emissions 17 percent below 2005 levels by 2020. Climate Action Plan at 4-5 (discussing pledge and plan to meet it).

recently in the agreement in principle reached with China,[3] existing fossil-fuel fired power plants are the largest concentrated domestic source of carbon pollution. In 2012, fossil fuel consumption for electricity generation accounted for over 37 percent of this country's CO_2 emissions.[4] Moreover, CO_2 persists in the environment, causing the greenhouse effect and therefore climate warming and climate damage, for centuries after it is emitted.[5] There is therefore no question that significant and timely permanent reductions in existing as well as new fossil-fueled EGU CO_2 emissions are sorely needed, globally, as an essential step towards avoiding the worst climate damage. And U.S. domestic EGU reductions are certainly needed as well. The U.S. simply cannot meet the greenhouse gas reduction commitments we have made, without CO_2 emissions reductions from existing sources in this sector.[6] Moreover, as the President recognized, we have a *moral* obligation to future generations to take meaningful action now.[7]

Not only do CO_2 emissions from power plants drive climate change,[8] but the converse is also true -- climate change is expected to dramatically impact the electricity system. Increasing temperatures will alter the level, timing and geographic location of electricity demand, and more

---

[3] Press Release, U.S. - China Joint Announcement on Climate Change, Beijing, China (Nov. 12, 2014) *available at*: http://www.whitehouse.gov/the-press-office/2014/11/11/us-china-joint-announcement-climate-change.

[4] U.S. EPA, *Inventory of U.S. Greenhouse Gases and Sinks: 1990 – 2012*, at Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.) (Apr. 2014); U.S. EPA, *Greenhouse Gas Reporting Program 2013*, http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html.

[5] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,517 n.18 (Dec. 15, 2009). Climate damage already is occurring. For example, as the Third National Climate Assessment found: "Human-induced climate change means much more than just hotter weather. Increases in ocean and freshwater temperatures, frost-free days, and heavy downpours have all been documented. Global sea level has risen, and there have been large reductions in snow-cover extent, glaciers, and sea ice. These changes and other climatic changes have affected and will continue to affect human health, water supply, agriculture, transportation, energy, coastal areas, and many other sectors of society, with increasingly adverse impacts on the American economy and quality of life. 2014 NCA at 9. *See generally* Walsh, J., D. *et al.,* Ch. 2: Our Changing Climate. *Climate Change Impacts in the United States: The Third National Climate Assessment*, J. M. Melillo, Terese (T.C.) Richmond, and G. W. Yohe, Eds., U.S. Global Change Research Program, 19-67. doi:10.7930/J0KW5CXT, *available at*: http://nca2014.globalchange.gov/report (describing climate change's wide range of effects across the United States). *See also* IPCC, *IPCC Fifth Assessment Synthesis Report at* 3 (Nov. 1, 2014), *available at:* http://www.ipcc.ch/report/ar5/syr/("Human influence on the climate system is clear, and recent anthropogenic emissions of greenhouse gases are the highest in history. Recent climate changes have widespread impacts on human and natural systems.").

[6] And, as we reference elsewhere, see *infra* at 75-76, the need for direct regulation of methane emissions associated with natural gas production – projected to expand over the coming years with or without these power plant performance standards – is also essential if the U.S. is to achieve our stated climate objectives.

[7] Climate Action Plan. at 4. EPA's historic motor vehicle carbon pollution and mileage standards, *Light Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards,* 75 Fed. Reg. 25,324 (May 7, 2010) (Phase I) and 77 Fed. Reg. 62,624 (Oct. 15, 2012) (Phase II), are projected to significantly decrease U.S. domestic CO_2 emissions. See *infra* Figure 1. But more rules alone do not achieve enough CO_2 emissions reductions to meet U.S. goals.

[8] IPCC, *IPCC Fifth Assessment Synthesis Report at* 5 (Nov. 1, 2014) ("Emissions of CO_2 from fossil fuel combustion and industrial processes contributed about 78% of the total greenhouse gas emissions increase from 1970 to 2010").

intense storm activity and sea level rise will affect electricity infrastructure, as examples.[9]

Fortunately, the cost of reducing emissions are projected by some commentators to be less than will be the costs to meet additional demand for electricity under a business as usual scenario with higher temperatures.[10]

But the U.S. is currently falling short of our 2009 pledge (*See* Figure 1 below).[11] Figure 1 illustrates that the new source greenhouse gas power plant standards, the greenhouse gas standards for motor vehicles, and regional renewable energy standards (including the California ETS, but not including the Regional Greenhouse Gas Initiative) taken together are not sufficient to meet the President's pledge. Nor are the CO_2 reductions from these programs nearly enough to avoid the worst damage to our rapidly and continually warming planet.[12]

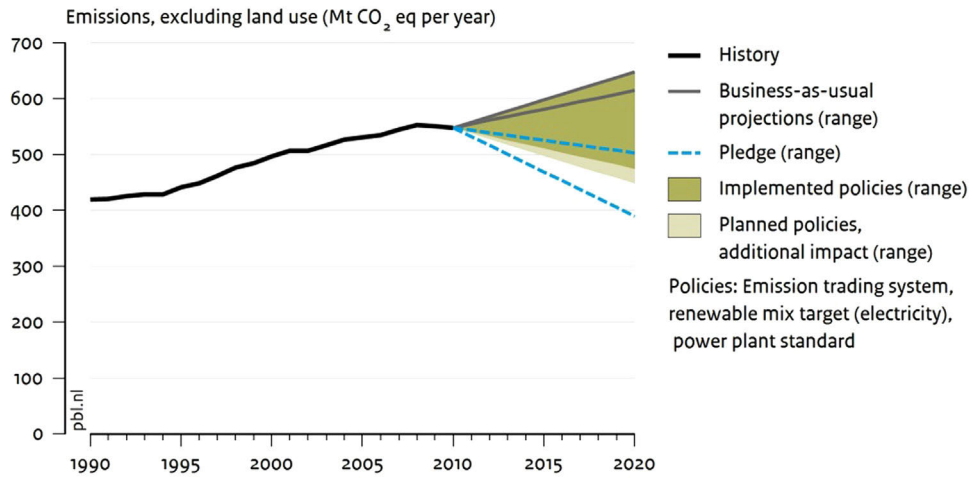


Figure 1: Impact of climate policies on greenhouse gas emissions projections for the USA. From: Mark Roelfsema, *et al.*, *Are major economies on track to achieve their pledges for 2020? An assessment of domestic climate and energy policies*, 67 ENERGY POLICY 781, 793 (2014) (Ex. 2).

b. Summary of CATF's comments and recommendations.

CATF agrees with EPA that its final existing source performance standards program must achieve CO_2 emissions reductions that are "quantifiable, non-duplicative, permanent, verifiable,

---

[9] Wendy S. Jaglom, *et al.*, *Assessment of projected temperatures impacts from climate change on the U.S. electric power sector using the Integrated Planning Model*, 73 ENERGY POLICY 524 (2014) (Ex. 1). Increasing temperatures have been projected to lead to a 39 percent increase in average annual cooling days by 2050 and increased power system costs of about $51 billion. *Id.* at 533.

[10] *Id.*

[11] Mark Roelfsema, *et al.*, *Are major economies on track to achieve their pledges for 2020? An assessment of domestic climate and energy policies*, 67 ENERGY POLICY 781, 791 (2014) (Ex. 2) (2012 projections show CO_2 emission levels at 8% below 2005 level by 2020).

[12] Alistor Doyle, *U.S., British Data Show 2014 Could be Hottest Year on Record*, Reuters (Nov. 27, 2014), *available at*: http://uk.reuters.com/article/2014/11/27/us-climatechange-heat-idUKKCN0JB1EM20141127 (2014 is on track to be the warmest year ever recorded).

and enforceable,"[13] and that the program itself must be capable of being practicably administered by the states and EPA acting under the cooperative federalism framed in the Clean Air Act.[14] For these reasons, our comments reach the following highlighted conclusions (while also offering comments on related issues):

1. EPA is well within its legal authority to propose and finalize carbon dioxide performance standards for existing EGUs.

2. EPA should finalize state targets based on its "reduced utilization" alternative best system of emissions reduction ("BSER"), specifically, based on that formulation under which target setting is based on a BSER consisting of an expanded building block 1 (which we call unit-specific measures), coupled with reduced utilization of the designated facilities through redispatch to lower-emitting units, and through increased reliance on nuclear energy, energy efficiency, and truly low-emitting renewables.

3. While EPA's interim and final target emission rates are reasonable, because they can be achieved in a variety of ways by states, they are also overly conservative, in several ways, and can be strengthened.

4. Building block 1 more properly should be framed as including "unit specific measures," some of which may not be available in all parts of the country at present (just as building block 3 recognizes "renewables" as inclusive of a basket of technologies that can reduce affected source utilization but are not all available in every part of the country). Reframed building block 1 would include *all* available measures for reducing CO_2 emissions in a state, so as to reflect not only heat rate improvement, but also available natural gas co-firing at coal units, carbon capture and sequestration ("CCS") retrofits (on existing coal or natural gas units), and unit retirements.

5. EPA's modeling should better reflect the reality of CCS retrofits. CATF's modeling results, which adjust EPA's incorrect assumptions using real world information, demonstrate that 10 GW or more of carbon capture with EOR sequestration will be built in 3 states modeled during the period 2014-2030, and an additional 6 GW will be built in the rest of the continental U.S. Particularly if the Agency finalizes targets based on a BSER portfolio approach including building blocks 1 and 2 only, it is essential to reframe building block 1 to include an accurate understanding of the likelihood that CCS will be developed over the coming decades.

6. EPA should include new natural gas combined cycle ("NGCC") plants in the state goal calculation methodology to the extent that these units are under construction,

[13] 79 Fed. Reg. at 34,909-910. We assert that this rule must result in the deepest practicable reductions from this highly emitting industry.

[14] *Id.* at 34,891.

have been publicly announced, or are needed to replace announced retiring coal capacity.

7. EPA's treatment of biomass is internally inconsistent, contrary to scientific consensus about the climate impacts of biogenic emissions, and contrary to law.

8. The best method for achieving the targets proposed for existing affected sources – in order to promote the goals of quantifiable, non-duplicative, permanent, verifiable, and enforceable CO_2 reductions, is through the implementation of a mass-based system allowing for the trading of allowances between designated facilities. Such a system should incorporate a firm ceiling on designated facility emissions. CATF strongly recommends that EPA provide a model rule, suitable for voluntary adoption by states into their CPP Implementation Plans, defining approvable parameters of a multistate mass-based allowance system, and offer implementation assistance from the Clean Air Markets Division for participating states. At a minimum, EPA should provide guidance, including a set of parameters for states to rely on in developing their own interstate mass allowance programs, including provision for allowance trading and banking, as well as incentives for states to include new sources as well as existing sources in the programs, for early reductions and for units retiring prior to 2030.

II. EPA's CPP is well within EPA's authority – Indeed, EPA could have directed States to secure more reductions from this industry.

EPA's proposed rule sets state-specific emissions rate-based CO_2 targets, based on a four "building block" best system of emission reduction ("BSER")[15] for existing units in subparts Da and KKKK ("EGUs"). EPA's building blocks, all of which when properly implemented will lead to lower CO_2 emissions from the designated EGUs, including heat rate improvements at affected facilities (building block 1), redispatch of lower-emitting units to displace higher-emitting affected units (building block 2), the increased reliance of the electricity system on low- or zero-carbon energy production (building block 3) and energy efficiency (building block 4).[16]

EPA computes state-specific target rates by, in effect, applying estimates of the availability of CO_2 reductions from those building blocks, to an adjusted 2012 baseline figure derived from actual emissions and generation data.[17] As an alternative to that approach, EPA proposes an alternative formulation of the BSER, under which the target rate setting is based on measures taken at the affected source (specifically building block 1 heat rate improvements), coupled with reduced utilization of the affected units in the amount available through redispatch

[15] 42 U.S.C. § 7411(a)(1). This statutory definition of "standard of performance" is applicable to both sections 111(b) and (d), and under it, standards of performance "reflect the degree of emission limitation achievable through the application of the best system of emission reduction…."

[16] 79 Fed. Reg. at 34,877. EPA explains in the proposal that building block 1 (heat rate improvement) alone is not sufficient as BSER for this industry, because there are additional strategies that are technically feasible, can be implemented at reasonable cost and result in greater emissions reductions. We agree.

[17] U.S. EPA, *Goal Computation Technical Support Document*, Doc. ID EPA-HQ-OAR-2013-0602-0460 (June 2014) [hereinafter *Goal Computation* TSD].

to lower-emitting affected units, and through increased reliance on nuclear energy, energy efficiency, and truly low-emitting renewables. As described *infra*, EPA is well within its authority to issue the standards it has proposed – the presumptive target rates are reasonable, and indeed are quite conservative, and the Agency's proposal is grounded in the statutory directives. And EPA has left the states a great deal of flexibility to meet the targets using a variety of measures in their plan submittals (not simply the measures EPA uses to define the target rates), and to comply based on mass-based state specific goals, through an allowance trading system.[18]

CATF urges the Agency to finalize the alternative "reduced utilization" formulation of the best system of emission reduction, with some expansion of building block 1 beyond heat rate improvement, to include other available "unit-specific measures" that achieve greater CO_2 emissions reductions directly at the affected facility at reasonable costs.[19] This reduced utilization formulation, combined with an expanded building block 1 is superior from both policy and legal perspectives, as it is simpler, more transparent, more readily enforceable, and most strongly grounded in the statutory commands.

EPA's recent announcement of possible methods for the translation of its state-by-state target emission rates into CO_2 mass-based targets is also certainly within the Agency's authority – and the resulting mass-based goals should be codified in the final rule.[20] And EPA also would be well within its authority to suggest the contours of a mass-based allowance system in response to the many states that seek more certainty and less complexity. That would result in a simpler, more transparent and stronger final rule.

a. Legal basis for CATF's position.

i. Background

Clean Air Act section 111(d) reflects the cooperative federalism that has characterized the Act since its initial inception, including its reference to state implementation of performance

[18] If anything EPA's proposed rule offers too many choices. While EPA's interest in preserving the states' authority to decide how best to comply with the CO_2 emissions targets is understandable, 'flexibility' should not overwhelm the Agency's authority to ensure permanent and enforceable reductions from existing sources. It is notable, as well that the docket also reflects a number of comments from states asking for more direction, particularly with respect to acceptable contours of a mass-based system for compliance. Comment submitted Sept. 4, 2014 by T. Marks, Director of Arkansas Dept. Envt'l Quality, on behalf of Midcontinent States Environmental and Energy Regulators (Illinois, Arkansas, and Michigan), EPA-HQ-OAR-2013-0602-16078; Comment submitted Sept. 5, 2014 by R. Flynn, New Mexico Env't Dept., EPA-HQ-OAR-2013-0602-17291; Comment submitted Sept. 12, 2014 by D. Wyant, Michigan Dept. Envt'l Quality EPA-HQ-OAR-2013-0602-17284; Comment submitted Sept. 16, 2014 by J.L. Stine, Minnesota Pollution Control Agency, EPA-HQ-OAR-2013-0602-17900; Comment submitted Sept. 18, 2014 by B. Shelly, President Navajo Nation, EPA-HQ-OAR-2013-0602-21646; Comment submitted Dec. 13, 2013 by Environmental Agency leaders from California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, and New York, EPA-HQ-OAR-2013-0602-0198.

[19] States should be asked to assess their performance standards based not only on heat rate improvements at affected units, but also on the availability of natural gas co-firing in coal units, CCS retrofits, and retirements that occur between 2012 and the date of CPP plan submittal by a state.

[20] As discussed below, *infra* at Sections II and III, EPA has ample authority to establish state emission goals in the form of emission rates or mass-based allowance systems, but the latter approach is clearly superior in many ways, and EPA should energetically facilitate, and indeed promote, the adoption of mass-based goals and implementation programs by states.

standards through a process "similar to that provided by [section 110]" of the Act.[21] The plan procedure set forth in section 110 requires states to submit plans to EPA for approval, reflecting standards set elsewhere in the Act and applicable to emission sources within each state.[22]

EPA's section 111(d) regulations,[23] which have been in effect for almost four decades, require states to submit plans to meet performance standards (which the regulations refer to as "guidelines") established by EPA. Those presumptive standards in turn are to be based on the "degree of emission limitation achievable though the application of the best system of emission reduction…the Administrator determines has been adequately demonstrated."[24] As is also the case under section 110, states are not compelled to adopt any specific implementation approach dictated by EPA, so long as their implementation plan will at least produce the emission reductions necessary to achieve the presumptive standards.

EPA must issue presumptive performance standard targets at the point when new sources of certain air pollutants emitted by sources in a particular industry are regulated under section 111(b).[25] The statute provides:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall adopt and submit to the Administrator a plan which (A) establishes standards of performance 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 emitted from a source category which is regulated under section 112 but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance….[26]

---

[21] Section 111(d) has been a part of the Act since 1970, and has been amended only once since that time.

[22] 42 U.S.C. § 7410(a).

[23] 40 C.F.R. §§ 60.20 - 60.29.

[24] 42 U.S.C. § 7411(a)(1).

[25] A "new source" includes "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [CAA § 111] which will be applicable to such a source." 42 U.S.C. § 7411(a)(2). On January 8, 2014, EPA proposed CO_2 new source performance standards ("NSPS") for subpart Da and subpart KKKK EGUs. Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430 (Jan. 8, 2014). Furthermore, EPA has long interpreted the statutory definition of "construction" to incorporate "reconstruction." "Proposed Rules: Standards of Performance for New Stationary Sources: Modification, Notification and Reconstruction," 39 Fed. Reg. 36,946 (Oct. 15, 1974) ("An existing facility, upon reconstruction, becomes an affected facility [for purposes of NSPS], irrespective of any change in emission rate"). And on June 18, 2014, EPA proposed CO_2 modified and reconstructed source performance standards for subpart Da and subpart KKKK EGUs. Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,960 (June. 18, 2014). Each of these proposals triggers the requirement that EPA must establish CO_2 emission guidelines for existing EGUs under section 111(d).

[26] 42 U.S.C. § 7411(d)(1).

The air pollutants regulated under section 111(d) are those which are not defined as hazardous within the meaning of CAA section 112 and not "criteria" pollutants (those for which national ambient air quality standards ("NAAQS") have been promulgated), but which nonetheless endanger public health and welfare.[27] As explained more fully below, section 111(d) has traditionally been a "gap-filling" provision – covering air pollutants that are neither criteria nor hazardous pollutants. This includes greenhouse gas pollutants like CO_2, which are not regulated either as hazardous air pollutants under section 112 or criteria pollutants under section 108. Commentators have challenged this understanding, basing their criticisms on minor technical amendments made to the section when Congress revised the Act in 1990.[28] They assert that the amendments radically changed the meaning of section 111(d) such that if an industry is regulated under section 112 for its *hazardous* air pollutants, it may not now also be regulated under section 111(d) for its emissions of air pollutants that are not section 112(b) hazardous pollutants or criteria pollutants. These commentators are wrong.

ii. The 1990 Clean Air Act Amendments did not change the "gap-filling" nature of Section 111(d), so as to preclude EPA's actions here.

Section 111(d) of the Clean Air Act before 1990 authorized EPA to regulate "any air pollutant which is not included on a list published under section 7408(a) or 7412(b)(1)(A) [112(b)(1)(A)] of this title."[29] When Congress amended the Act in 1990, it made a significant overhaul to section 112, to provide for more effective regulation of hazardous air pollutants emitted by stationary sources. Specifically, Congress, dissatisfied with EPA's delay in regulating toxic air pollutants, restructured section 112. Among other changes, Congress replaced section 112(b)(1)(A), which had required *EPA* to list hazardous air pollutants that it intended to regulate, with new section 112(b), in which *Congress* listed 189 substances as hazardous air pollutants.[30] After this amendment, the original reference to section 112(b)(1)(A) in section 111(d) no longer made sense, thereby necessitating a technical update.[31] Both Houses of Congress proposed housekeeping amendments to section 111(d). The Senate bill struck "112(b)(1)(A)" and replaced it with "112(b)," the new section providing the list of hazardous air pollutants.[32] The House bill

---

[27] Clean Air Act Amendments of 1970, Pub. L. No. 91-604 (1970). *See also* S. Rep. No. 91-1196, at 18 (1970) (discussing purpose of CAA § 111(d)). The 1975 EPA regulations implementing section 111(d) call such air pollutants "designated pollutants."

[28] *See* Comment submitted by Michael O. McKown, & Gary Broadbent, Murray Energy Corp., Docket No. EPA-HQ-OAR-2013-0602-11903 (Aug. 15, 2014) attaching Letter from Patrick Morrissey, Attorney General, State of West Virginia to Gina McCarthy, Administrator, U.S. EPA (June 6, 2014). Some have gone so far as to seek court review of this question, even before EPA's rule is finalized. *Murray Energy Corp. v. EPA,* No. 14-1151 (D.C. Cir. Filed Aug. 15, 2014), *consolidated with In re Murray Energy Corp.*, No. 14-1112 (D.C. Cir. Filed June 18, 2014).

[29] *See* 42 U.S.C. § 7411(d).

[30] *See* Pub. L. 101–549, § 301, 104 Stat. 2531 (1990); *see generally White Stallion Energy Ctr., LLC v. E.P.A.*, 748 F.3d 1222, 1229 (D.C. Cir. 2014) (discussing 1990 amendments to section 112).

[31] *See id.*

[32] S. 1630, as passed by the Senate on April 3, 1990, § 305(a), *reprinted in* U.S. SENATE COMM. ON ENVT. & PUB. WORKS, LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1990, at 4534 (1993).

struck "112(b)(1)(A)" and replaced it with the phrase "emitted from a source category which is regulated under section 112."[33]

The Senate-originated language requires EPA to regulate air pollutants subject to regulation under section 111(b), excluding air pollutants regulated under section 112(b). The amendment from the House excludes any pollutants "emitted from a source category which is regulated under section 112." The amendments were not discussed in committee hearings, floor debates, or in conference. Subsequently, both were enacted and signed into law. Only the House amendment appears in the U.S. Code, but Supreme Court precedent accords the codification "no weight."[34] Thus, the Statutes at Large, which include both amendments, control in this situation.[35]

This legislative oddity does not preclude EPA regulation of greenhouse gases under section 111(d). Both amendments must be given effect unless there is some demonstrable significant defect, such as scrivener's error. And the Senate amendment—which plainly permits greenhouse gas regulation—cannot be ignored. While language may be disregarded as a scrivener's error where it has "no plausible interpretation,"[36] or "produce[s] a result demonstrably at odds with the intentions of its drafters,"[37] the Senate amendment bears neither of those characteristics, as it reasonably retains EPA's longstanding authority under section 111(d) to regulate non-criteria and non-hazardous pollutants.

Moreover, excluding greenhouse gases (or any other pollutant that is neither regulated under section 112 nor sections 108-109) is in conflict with the plain language of the statute, as it would render the Senate amendment meaningless.[38] The Senate amendment mandates EPA to regulate greenhouse gases, as they do not fall under section 108 or section 112(b) of the Clean Air Act. Even if the two amendments are interpreted as inconsistent, EPA must attempt to give effect to both, rather than simply discarding one.[39]

---

[33] S. 1630, as passed by the House of Representatives on May 23, 1990, § 108(f), *reprinted in* VOLUME I: LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1990, at 1979 (1993).

[34] *United States v. Welden*, 377 U.S. 95, 98 n.4 (1964).

[35] *See Stephan v. United States*, 319 U.S. 423, 426 (1943) (finding that "the [United States] Code cannot prevail over the Statutes at Large when the two are inconsistent"); *U.S. National Bank of Oregon v. Independent Insurance Agents of America, Inc.*, 508 U.S. 439, 448 (1993)(the Statutes at Large are "legal evidence of the laws").

[36] *Williams Companies v. FERC*, 345 F.3d 910, 912 n.1 (D.C. Cir. 2003).

[37] *Griffin v. Oceanic Contractors, Inc.*, 458 U.S. 564, 571 (1982).

[38] *New York v. EPA*, 443 F.3d 880, 887 (D.C. Cir. 2006) ("[C]ourts must give effect to each word of a statute.").

[39] *See Morton v. Mancari*, 417 U.S. 535, 551 (1974) (quoting *United States v. Borden Co.*, 308 U.S. 188, 198 (1939)) (finding that absent "clear and manifest" congressional intention to contrary, the rule is to give effect to both provisions). In *Citizens to Save Spencer County v. EPA*, the agency was confronted with seemingly inconsistent amendments in the Clean Air Act, and that also were never reconciled in conference. 600 F.2d at 872. The D.C. Circuit explained that EPA's task, under *Chevron, v. NRDC*, 467 U.S. 837, 842 (1984), was "to pursue a middle course that vitiates neither provision but implements to the fullest extent possible the directives of each," and courts

And the House amendment can be read as consistent with the Senate amendment, to preclude a source category from regulation under section 111(d) for a pollutant only when that source category is regulated under section 112 for *that same pollutant*. Thus, because section 112 is not used to regulate sources for their greenhouse gases, EPA is free to regulate those emissions under section 111(d).[40] The House amendment therefore can be read merely to state in different terms the same meaning as the Senate amendment. The overall structure of the Clean Air Act and the legislative history of the 1990 Amendments support this reading. The 1990 Amendments – particularly the significant changes made to section 112 – were part of an effort to strengthen and update the air pollution regulatory scheme, marked by *increased* controls, gap-filling, and decreased EPA authority to allow regulatory evasion; certainly not a legislative attempt to *scale back* on regulation, or to *create* holes or gaps in the regulatory structure for some pollutants. In revising section 111(d), Congress most likely meant only to update the language to comport with the overhaul of section 112. Indeed, the House amendment is found under the heading "Miscellaneous Provisions" and the Senate amendment under "Conforming Amendments."[41] Coupled with the signed bill containing an explanatory footnote describing the two amendments as "duplicative," both changes to section 111(d) appear to be simply different versions of the same technical edit.[42] That edit was to ensure continued application of section 111(d) to regulate air pollutants that are neither criteria pollutants nor hazardous pollutants under the new section 112(b).

---

needed only to assess whether the agency had "effected an appropriate harmonization of the conflicting provisions while remaining within the bounds of that agency's statutory authority." *Spencer County,* 600 F.2d at 871. The court also noted that "maximum possible effect should be afforded" to both provisions and "none of those provisions rendered null and void"). *Id.* at 870. Section 111(d)'s two amendments also create the type of ambiguity that EPA may reasonably resolve.

[40] Even if the Senate amendment were disregarded, the House amendment by itself has several different readings that would permit greenhouse gas regulation. The House amendment excludes pollutants "emitted from a source category which is regulated under section 112." The only reading that bars greenhouse gas regulation is one that presumes any source category already regulated under section 112 for *any type* of pollutant is foreclosed from regulation under section 111(d). Because EPA already regulates the sources that emit greenhouse gases for hazardous air pollutant emissions under section 112, this reading of the House amendment would preclude section 111(d) regulation for those sources. But such a reading leads to a puzzling result: it wholly exempts sources from being regulated for dangerous pollutants based on those sources already being regulated for *other* unrelated pollutants. *See Desert Citizens Against Pollution v. EPA*, 699 F.3d 524, 527–28 (D.C. Cir. 2012) (rejecting petitioners' interpretation of statute that would have had the "anomalous effect of changing the required stringency" for a given source's emissions "simply on the fortuity" of other emissions from that source). More troubling still, this reading would essentially strip section 111(d) of any real effect, because many large industrial sources are regulated for hazardous air pollutants under section 112. In theory, then, those sources would be outside the scope of section 111(d), which would raise the question of what exactly the provision is supposed to regulate. *Cf. Davis County Solid Waste Management v. EPA*, 101 F.3d 1395, 1404 (D.C. Cir. 1996) ("[I]t is of course a well-established maxim of statutory construction that courts should avoid interpretations that render a statutory provision superfluous.").

[41] Pub. L. No. 101–549, §§ 108, 302(a), 104 Stat. 2399, 2467, 2547 (1990).

[42] 1 ENVIRONMENT AND NATURAL RES. POLICY DIV., LIBRARY OF CONGRESS, A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1990, at 46 (1998).

In any event, construing the two amendments as prohibiting greenhouse gas regulation under section 111(d) is the least rational approach as well as the least reflective of congressional intent. Congress surely could not have desired to effect a sweeping, substantive change to the provision by exempting a large class of pollutants in an otherwise stylistic updating effort, all without the benefit of any debate or discussion. This would be especially inconsistent with the general drafting of the Clean Air Act, given that Congress *did* make a number of major, substantive changes to the statute in the 1990 Amendments, like section 112, but when it did so, those changes were not quietly tacked on to a housekeeping bill. Congress "does not, one might say, hide elephants in mouseholes."[43]

Here, EPA's interpretation maintains the longstanding purpose of section 111(d) in controlling dangerous pollutants not otherwise regulated under other sections of the Clean Air Act. EPA's resolution of this ambiguity sufficiently harmonizes the two amendments and is a permissible construction that merits *Chevron* deference.

iii. EPA's directives to States must be based on the "best system of emissions reduction" ("BSER").

EPA's longstanding rules reflect an understanding that under section 111(d) the Agency will presumptively define existing source emissions performance standards in a rulemaking, basing the standards on "the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities."[44]

Because the statute uses the term "standard of performance" in both sections 111(b) and (d), the same statutory definition of "standard of performance" applies to existing source standards under section 111(d) as applies to new source standards under section 111(b), including the phrase "best system of emissions reduction." Section 111(d) has been only rarely used since its enactment,[45] and there are no court decisions providing further interpretation of the

---

[43] *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001).

[44] 40 C.F.R. § 60.21(e); 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975) (describing the standards of performance set by the Agency under section 111(d) as "guidelines" but in so doing, adopting the statutory text of 111(a)(1)).

[45] EPA has proposed thirteen CAA section 111(d) emission guidelines; however only three stand-alone 111(d) emission guidelines have been finalized: Large municipal waste combustors, 40 C.F.R. §§ 60.30a – 60.39a; Municipal solid waste landfills, 40 C.F.R. §§ 60.30c – 60.36c; and Sulfuric acid production units, 40 C.F.R. §§ 60.30d – 60.32d. Six other final rules were issued, under section 129 which expressly require section 111(d) regulation of certain air pollutants emitted by solid waste incineration units only: Large municipal waste combustors constructed on or before September 20, 1994, 40 C.F.R §§ 60.30b – 60.39b (promulgated in conjunction with CAA § 129); Hospital/Medical/Infectious Waste Incinerators, 40 C.F.R. §§ 60.30e – 60.39e (promulgated in conjunction with CAA § 129); Small municipal waste combustion units constructed on or before August 30, 1999, 40 C.F.R. §§ 60.1500 – 60.1940 (promulgated in conjunction with CAA § 129); Commercial and industrial solid waste incineration units that commenced construction on or before November 30, 1999, 40 C.F.R. §§ 60.2500 – 60.2857 (promulgated in conjunction with CAA § 129); Other solid waste incineration units that commenced construction on or before December 9, 2004, 40 C.F.R. §§ 60.2980 – 60.3078 (promulgated in conjunction with CAA § 129); Existing sewage sludge incineration units, 40 C.F.R. §§ 60.5000 – 60.5250 (promulgated in conjunction with CAA § 129). Three other rules were either vacated or never codified: Coal-fired electric utility steam generating units, Clean Air Mercury Rule, 70 Fed. Reg. 28,606 (May 18, 2005) (subsequently vacated by the D.C. Circuit Court of

statutory term BSER in the 111(d) context. There are, however, cases evaluating how a standard of performance is to be set under section 111(b) for new sources. Those cases find that EPA has significant authority in selecting a BSER and setting standards, "to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present."[46] But EPA's authority is not unbounded. The BSER must "be 'adequately demonstrated' and the [performance] standard itself 'achievable,'"[47] that is, "one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."[48] EPA "may base its determination that a technology is adequately demonstrated or that a standard is achievable on …the reasonable extrapolation of a technology's performance in other industries."[49] EPA correctly notes that a shared objective of both new and existing source standards under section 111 is that they must promote innovation and otherwise be "technology forcing"[50] in their particular spheres.[51] That concept reasonably has a different meaning in the context of new sources regulated under section 111(b) than when applied to existing sources, but it is nevertheless also relevant to the determination of the BSER underlying section 111(d) existing source performance standards.

Appeals); Phosphate fertilizer plants, 42 Fed. Reg. 12,022 (Mar. 1, 1977) (never codified); Kraft pulp mills, 44 Fed. Reg. 29,828 (May 22, 1979) (never codified); Primary aluminum plants, 45 Fed. Reg. 26,294 (Apr. 17, 1980) (never codified).

[46] *Sierra Club v. Costle*, 657 F.2d 298, 330, 331 (D.C. Cir. 1981); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999)(standards must "serve the interests of pollution control" but not be "exorbitantly costly in an economic or environmental way"). Costs imposed by the standard are not "greater than the industry could bear and survive" but instead are costs to which the industry can "adjust" in a "healthy economic fashion to the end sought by the Act as represented by the standards prescribed. *Portland Cement Ass'n v. Train,* 513 F.2d 506, 508 (D.C. Cir. 1975). Most pollutants regulated under section 111(b) new source standards are either criteria or hazardous pollutants, and thus not subject to §111(d) regulation.

[47] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 430 (D.C. Cir. 1980).

[48] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir 1973). *See also Portland Cement Ass'n v Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (rejecting the suggestion of the cement manufacturers that the Act's requirement that emission limitations be "adequately demonstrated" necessarily implies that any cement plant now in existence be able to meet the proposed standards").

[49] *Lignite Energy Council v. EPA,* 198 F.3d 930, 934 (D.C. Cir. 1999).

[50] *See id.* (section 111 looks to what fairly may be projected for the regulated future, not the state of the art at present)(citing *Portland Cement v. Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)); *Nat'l Lime Ass'n. v. EPA*, 627 F.2d 416, 433 n. 46 (D.C. Cir 1980) ("An achievable standard need not be one already routinely achieved in the industry."). Section 111 was designed "to assure the use of available technology and to stimulate the development of new technology." S.Rep.No. 95-127, at 171. EPA, therefore, maintains the authority "to induce, to stimulate and augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution." *Sierra Club*, 657 F.2d at n. 174. *C.f.*, Nicholas A. Ashford, *et al*., *Using Regulation to Change the Market for Innovation*. 9 HARV. ENVT'L L. REV 419 (Summer 1985) (describing the power of regulatory design, particularly stringent regulations, to drive technological change and consequently, air pollution emissions reductions).

[51] 79 Fed. Reg. 34,890.

In the case of section 111(d) standard setting, the statute requires EPA to allow states to "take into account the remaining useful life" of any regulated source, in their implementing plans – that is, in their compliance with the target standards. That language does not give EPA authority to ignore older affected sources in the standard setting process if they are planned for retirement, however.

iv. EPA's alternative "reduced utilization" BSER formulation is preferred.

EPA has proposed two formulations of the BSER as alternatives for use in state emissions limit target setting.[52] Each recognizes the reality of the interconnected nature of the electric system, which enables lower or zero CO_2 emitting sources to substitute for the higher-emitting affected sources, thereby reducing CO_2 emissions from the affected sources overall.[53] EPA's first approach relies on a combination of building blocks 1 through 4, and assumes that any increased dispatch of lower CO_2 emitting natural gas-fired generation to displace existing coal units, plus increases in renewable generation and energy efficiency measures will decrease generation (and therefore also CO_2 emissions) at the affected sources.[54] The second alternative BSER approach offered by EPA, identified as consisting of building block 1 coupled with "reduced utilization" of the designated facilities, is grounded more closely in EPA's statutory authority to direct emissions reductions from the affected sources. This "reduced utilization" BSER is also simpler, more transparent, and easier to comply with, because CO_2 emissions reductions at the designated facilities (caused by reduced utilization of those sources) can be readily and directly measured, reported and enforced.

As we note *infra* at Sec. III.a, we comprehend EPA's building block 1 as potentially (and preferably) encompassing not only heat rate improvements, but also other "unit specific measures" that can demonstrably achieve CO_2 emissions reductions measurable directly at the unit or facility, including for example, retrofit carbon capture (and sequestration on- or off-site), natural gas co-firing in a coal unit, or certain firm unit retirements already undertaken or announced. We strongly encourage the Agency to finalize that understanding of building block 1, particularly if the Agency chooses in the final rule to derive state targets using a BSER including only building blocks 1 and 2 (a formulation also described as a potential alternative).[55]

Under the reduced utilization alternative, EPA identifies the BSER as building block 1 coupled with "a component consisting of reduced generation from higher emitting affected EGUs, with the measures in the other building blocks serving as the basis for quantifying the amounts of generation reductions and consequent CO_2 emissions reductions…."[56] Under this

---

[52] *See* 79 Fed. Reg. at 34,885 – 89 *and* 79 Fed. Reg. at 34,889 – 90.

[53] 79 Fed. Reg. at 34,880 – 81.

[54] 79 Fed. Reg. at 34,880.

[55] *Id.* at 34,879, 34,884.

[56] *Id.* at 34879.

formulation, sources not only apply unit-specific control measures, but some designated facilities are used less often. This reduced utilization produces reduced CO_2 mass emissions, specifically in the amount achievable through the measures in building blocks 2 through 4: increased reliance on natural gas-fired EGUs, nuclear and renewable energy and energy efficiency.[57] EPA asserts that: "reducing generation and therefore emissions from some or all affected EGUs… due to the interconnected and integrated nature of the grid, would elicit the responses identified in building blocks 2, 3, and 4 of increasing generation at lower-emitting EGUs or reducing the demand for electricity services."[58]

EPA may create indirect incentives for actions it cannot directly require[59] (for example increased development of and reliance on renewable energy and energy efficiency), so long as it does so through a mechanism within its statutory purview, such as achieving CO_2 reductions through reduced utilization of affected sources. Thus, the alternative formulation of BSER under which building blocks 3 (low- or zero-emitting generation sources) and 4 (energy efficiency) reduce utilization of higher emitting affected sources is within EPA's authority.

EPA is constrained by the statute's terms to regulate existing sources in an industry and for a pollutant for which the Agency has regulated new sources,[60] and limited to setting standards reflecting a BSER that is "rationally related to reality."[61] Natural gas redispatch, energy efficiency measures and increased reliance on zero or near-zero emitting renewable energy generation are now used by states and the industry to curtail operation of higher-emitting sources and thereby reduce CO_2 emissions from designated facilities. Their costs are clearly "reasonable" as they are already in widespread use. Including them in the BSER will provide indirect incentives for further innovation in these CO_2 reducing technologies – precisely the kind of

---

[57] 79 Fed. Reg. at 34,889.

[58] 79 Fed. Reg. at 34,881. *See also* Jonas Monast, *et al., Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency*, 42 ELR 10206 (Mar. 2012) (Reduced utilization is a "traditional compliance mechanism under CAA § 111 and will incent demand-side energy efficiency programs and renewable energy generation."). Reduced utilization has been recognized as an adequately demonstrated pollution control mechanism for decades. *See* U.S. EPA, *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units*, at 82 n.66 (June 2014) (discussing Congress's recognition in 1970 that SIP requirements may retire pollution sources in order to achieve the NAAQS).

[59] *See Connecticut Dept. Public Util. Control v. FERC,* 569 F.3d 477 (D.C. Cir. 2009) (finding that FERC could create incentives in areas that are within the states' jurisdiction, so long as states retain the right to opt out). *Compare Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rehearing en banc denied per curiam* (9/17/2014) (striking down FERC's attempt to set prices for wholesale demand response measures agreed to by retail customers, as an impermissible incursion into retail markets, not an indirect incentive).

[60] *See Nat'l Asphalt Pavement Ass'n v. Train,* 539 F.2d 775, 783 (D.C. Cir. 1976); *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973); 42 U.S.C. § 7411(d)(1).

[61] EPA's BSER essentially models foreseeable ways to control CO_2 pollution from designated facilities. Such a model must rationally relate to the reality it purports to represent. *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998)).

technological innovation leading to decreased costs associated with pollution control that the standard setting process is intended to yield.[62]

And the concept of "reduced utilization"[63] of the regulated sources is not new, but has long been recognized as a pollution control measure under the Clean Air Act.[64] For example, the plain text of the 1990 Acid Rain provisions includes the reduced utilization language, as well as references to energy efficiency, showing that Congress clearly intended that pollution controls of the kind contemplated by EPA as the BSER in this rule could "reduce utilization" of existing EGUs, even to the point of unit retirement.[65]

We do not suggest that EPA may not also conclude that building blocks 2 through 4 comprise a BSER for the affected sources in light of the integrated nature of the electricity grid, because all of the building blocks lead to reduced CO_2 emissions at the affected sources.[66] However, the alternative "reduced utilization" BSER is a simpler formulation. On the implementation side, it is the CO_2 reduction associated with reduced utilization of affected sources that can be most simply, easily, and accurately quantified, tracked, monitored, and enforced. Such reductions also are squarely within the control of the affected sources and owners and operators would not have to rely on participation of non-regulated entities.

v. CATF supports correction of the goal-setting formula, to more directly tie building block 3 and building block 4 measures to CO_2 emissions reductions at the designated facilities.

On October 30, 2014, EPA issued a Notice of Data Availability ("NODA"), making available to the public ideas EPA received from stakeholders in early comments including the

---

[62] *Lignite Energy Council,* 198 F.3d at 934.

[63] 79 Fed. Reg. at 34,889.

[64] See, *e.g.*, Consent Decree, *United States v. Tampa Electric Co*., Civ. No. 99-2524 (M.D.Fla. 2004) at 7-8 (presuming permanent shut-down amongst "emissions reductions and controls"), *available at*: http://www2.epa.gov/sites/production/files/documents/tecocd.pdf. And, in a case related to analogous performance standards for existing facilities under the Clean Water Act, the Supreme Court found that Congress understood that existing source standards might lead to the closure or curtailment of some sources *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 76 (1980). In *Crushed Stone*, EPA set a performance standard under Clean Water Act section 301(b)(1) reflecting the "best practicable control technology currently available" for existing sources, and did not allow variances for plants that could not meet the standard for economic reasons. *Id.* at 69. The Court concluded that Congress foresaw and accepted that effluent limitations would lead to closures, and that EPA was within its authority to require plants either to meet the standard or cease operations. *Id.* at 83.

[65] *See* 42 USCS § 7651g(c)(1)(B) (emphasis added): "In the case of a compliance plan for an affected source under sections 404 and 407 [42 U.S.C. §§ 7651c and 7651f] for which the owner or operator proposes to meet the requirements of that section by *reducing utilization of the unit as compared with its baseline or by shutting down the unit,* the owner or operator shall include in the proposed compliance plan a specification of the unit or units that will provide electrical generation to compensate for the reduced output at the affected source, *or a demonstration that such reduced utilization will be accomplished through energy conservation or improved unit efficiency*. …" See also *infra* at Sec. III.a.iii discussing retirements.

[66] 79 Fed. Reg. at 34,889 n. 237.

goal calculation formula.[67] Stakeholders identified the inconsistency between EPA's treatment of building block 2 in the goal calculation as compared to building blocks 3 and 4. Specifically, while redispatched natural gas-fired generation displaces historic coal-fired generation in the goal calculation, renewable energy generation and reduced generation from energy efficiency measures are considered additional to historic generation rather than as substitutes for the designated facilities.[68] EPA proposed changes to the goal setting formula to better align the state goal setting process with the reduced utilization BSER.

While CATF asserts that a mass-based approach has significant advantages over a rate-based approach (see *infra* Section IV), we strongly agree with the Agency that any final rate-based equation must treat the BSER building blocks consistently and should reflect the resulting projected emissions reductions at the existing subpart Da and KKKK designated facilities. We also agree that the goal-setting equation originally proposed by the Agency in June 2014 reduces generation at coal-fired sources to the extent that generation is redispatched to natural gas-fired sources under building block 2[69], but the reductions due to the measures included in building blocks 3 and 4 are applied as additional to those achieved at the affected sources. The resulting state emissions rate therefore simply dilutes the target emissions rate to be achieved by the designated facilities rather than ensuring emissions reductions.

This outcome is avoided by the alternative "reduced utilization" BSER formulation, and because we prefer that formulation, we also support the correction to the rate calculation formula proposed in the NODA.[70] Measures from building block 3 and 4 should explicitly reduce the generation from the covered sources in the goal-setting equation.[71] Further, to achieve the maximum emissions reductions practicable using the *best* system of emission reduction, the equation should prioritize real reductions from high-intensity carbon emitters.[72] Therefore, the generation from building blocks 3 and 4 should be modeled as replacing replace generation from existing affected units first.

We therefore urge EPA to finalize a goal setting computation that simply takes the sum of a state's incremental renewable energy and energy efficiency megawatt hours, and subtracts it from the affected coal generation megawatt hours. Taking the Ohio goal data computation

---

[67] 79 Fed. Reg. 64,543 (Oct. 30, 2014).

[68] *Id.* at 64,547.

[69] *Goal Computation TSD* at 10-14.

[70] 79 Fed. Reg. 64,543, 64,552-53.

[71] *Id.* at 64,552. EPA explicitly states that the best system of emission reduction includes "[r]educing emissions *from affected EGUs* in the amount that results from *substituting generation at those EGUs* with expanded low- or zero-carbon generation" and "in the amount that results from the use of demand-side energy efficiency that *reduces the amount of generation* required." 79 Fed. Reg. at 34,836 (emphasis added). This reflects likely behavior in response to the CPP.

[72] 79 Fed. Reg. at 64,553. *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d. 427, 437 (D.C. Cir. 1973) (explaining Congressional intent that the best system of emission reduction achieve the maximum degree of pollution control practicable.)

example that EPA used in the Goal Computation TSD, if EPA accounted for the resulting reduced utilization at coal-fired power plants by totaling the amount of increased renewable energy and energy efficiency, the generation at affected existing coal-fired plants would decrease by 28,321,566 MWh. This adjustment decreases the final CO_2 emissions coming from coal-fired plants and leads to a reduction in the state goal for Ohio from 1,338 lb./MWh to 1,173 lb./MWh. And, this minor adjustment to the goal-setting equation more accurately reflects how states will comply, treats the building blocks consistently, and ensures that the emissions reductions associated with the building blocks lead to CO_2 reductions from the designated facilities.

vi. Mass-based allowance trading mechanisms for compliance are contemplated by the Clean Air Act and the Agency's longstanding section 111(d) Rules.

1. Mass-based allowance trading is consistent with the Agency's rules, and with precedent.

EPA's rules explain that approvable state plans may incorporate emissions standards in the form *either* of an allowance system, or expressed, as allowable rates, and the plan further must include compliance schedules applicable to all designated facilities within the state.[73] EPA will then approve the plan if it is timely and satisfactory.[74] EPA concluded that for pollutants to which section 111(d) applies and that endanger public health, a satisfactory plan must "establish emission standards that …are equivalent to or more stringent than EPA's emission guidelines."[75]

As long ago as 1998, EPA recognized that under a section 110 State Implementation Plan process, allowance trading mechanisms had been developed and used successfully in the electric generating sector.[76] And, the only Congressional effort to date that exclusively addresses power plant emissions reductions is the Title IV Acid Rain Program, which is a mass-based allowance trading system covering the sector. The Acid Rain Program not only provides evidence that Congress clearly intended emissions reductions from existing (and new) power plants could be achieved using a mass-based allowance trading system, but that measures such as energy conservation and efficiency improvements could be used to achieve such reductions.[77]

---

[73] 40 C.F.R. § 60.24(b)(1).

[74] 40 C.F.R. § 60.27.

[75] *See* 40 Fed. Reg. 53,340, 53,342 (Nov. 17, 1975) (explaining that EPA interprets its duty to determine whether a state plan is "satisfactory" as requiring promulgation of substantive criteria including an appropriate best system of emission reduction). EPA is not re-opening its interpretation of "satisfactory" in 42 U.S.C. § 7411(d)(2)(A) in the current proposal. 79 Fed. Reg. at 34,852. Nor should it. Moreover, section 116 specifically prohibits States to adopt or enforce emissions standards under section 111 that are "less stringent than the standard or limitation." 42 U.S.C. § 7416.

[76] EPA, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57356, 57457 (Oct. 27, 1998).

[77] *See* 42 U.S.C. §§ 7651b (general authority for allowance program); § 7651c (definitions of qualified energy conservation and renewable energy measures, and describing formulas for calculating avoided EGU emissions from each).

Nothing in section 111(d) prohibits the adoption of a mass-based allowance trading mechanism under the CPP, indeed the Agency's rules expressly state that approvable state plans, which the statutes expressly frames as "similar" to section 110 plans, may include either emissions rates or an allowance system.[78] Congress in 1990 removed the word "technology" from the section 111(a) definition of "performance standards," indicating that the application of specific technologies is not a requirement of section 111.[79] While that in no way reduces the technology-forcing nature of section 111 performance standards, which has been subsequently recognized,[80] it does provide support for existing source standards based on "systems" of emission reduction that go beyond the application of source-specific control technology requirements.

vii. There is no merit in arguments that multistate plans for compliance with the CPP would violate the Compact Clause of the U.S. Constitution

Some commentators have suggested that EPA's proposal that multiple states may submit a joint compliance plan to implement the CO_2 emissions targets for existing sources,[81] may violate the Compact Clause of the U.S. Constitution, or at the very least would require Congressional approval.[82] The Compact Clause provides that "[n]o State shall, without the Consent of Congress … enter into any Agreement or Compact with another State, or with a foreign Power, or engage in War unless actually invaded, or in such imminent Danger as well not admit of delay."[83] Critics argue that multi-state plans amount to interstate compacts and cannot be put into place without specific congressional authorization. We do not agree.

---

[78] 40 C.F.R.§§ 60.21(f), 60.24(b)(1); *see also* 42 U.S.C. § 7411(d)(1) (framing the state plan process as similar to those under section 110).

[79] Gregory E. *Wannier, et al.,* Prevailing Academic View on Compliance Flexibility under §111 of the Clean Air Act, Resources for the Future Discussion Paper, 4 & n.16 (July 2011), *available at* http://www.rff.org/RFF/Documents/RFF-DP-11-29.pdf.

[80] *Lignite Energy Council,* 198 F.3d at 934; *see also* Robert Sussman, *Power Plant Regulation Under The Clean Air Act: A Breakthrough Moment for US Climate Policy?,* 32 VA. L. REV. 97, 123 (2014) (noting the "technology forcing thrust" of section 111(d) standards).

[81] 79 Fed. Reg. at 34,915.

[82] Raymond L. Gifford *et al*., *State Implementation of CO_2 Rules: Institutional and Practical Issues with State and Multi-State Implementation and Enforcement*, (July 2014), *available at*: http://www.wbklaw.com/uploads/file/Articles- News/White Paper - State Implementation of CO2 Rules.pdf (arguing that EPA SIP approval criteria will require interstate enforcement mechanisms, which will implicate the Compact Clause); Matthew Pincus, *When Should Interstate Compacts Require Congressional Consent?,* 42 COLUM. J. L. & SOC. PROBS. 511 (2009) (discussing RGGI compact and the balance of power between the federal government and states).

[83] U.S. CONST. art. I, § 10, cl. 3.

First, Congress has already sanctioned agreements of this nature under the Clean Air Act. Under the Compact Clause, Congress may give explicit or implicit authorization to compacts, and it may do so for all interstate agreements of a particular subject matter. For example, in *Cuyler v. Adams*, Congress authorized joint state action on criminal enforcement and allowed states to coordinate on policies and laws in the Crime Control Consent Act of 1934.[84] The language of the statute did not authorize a *specific* compact, but rather, approved future interstate agreements for the general purpose of "mutual assistance in the prevention of crime."[85] Similarly, Congress foresaw interstate coordination on air pollution issues. Clean Air Act section 102 expressly instructs the Administrator to "encourage cooperative activities" and "*encourage the making of agreements and compacts between States for the prevention and control of air pollution*." This provision cannot be interpreted in any way other than that Congress anticipated interstate compacts as a useful tool and pre-authorized them for efforts to improve air pollution control. As in the Crime Control Consent Act, Congress has granted consent, in a capacious manner so that states would have the flexibility to accomplish a general legislative goal. Here, multi-state plans comfortably qualify under the broad purpose of "prevention and control of air pollution."

Second, the Supreme Court has never interpreted the Compact Clause to require Congressional approval of *every* agreement between multiple states. In one of its earliest cases concerning the Compact Clause, the Court remarked, "[t]here are many matters upon which different states may agree that can in no respect concern the United States."[86] The Court repeatedly recognized in subsequent cases that the Constitution "did not purport to exhaust imagination and resourcefulness in devising fruitful interstate relationships" and it was "not to be construed to limit the variety of arrangements which are possible through the voluntary actions of individual States with a view to increasing harmony within the federalism created by the Constitution."[87] Having established in *Virginia v. Tennessee,* 148 U.S. 503, 518 (1983), that the Compact Clause did not apply to all interstate agreements, the Court affirmed that position in *New Hampshire v. Maine*, 426 U.S. 363 (1976), another state boundary dispute case, and again declined to broaden its reading of the Compact Clause in *United States Steel Corporation v. Multistate Tax Commission*, 434 U.S. 452 (1978).

In *Multistate Tax*, the Supreme Court explained in detail which interstate agreements require Congressional approval, and laid out the applicable test.[88] The case involved multi-state corporate taxpayers seeking to invalidate a compact between twenty-one states that created an administrative body to facilitate determination of liability for multi-state taxpayers and avoid duplicative taxation.[89] The Court stated that "[t]he relevant inquiry must be one of impact on our

---

[84] *Cuyler v. Adams*, 449 U.S. 433, 441-42 (1981).

[85] *Id.* (quoting 4 U.S.C. § 112(a)).

[86] *Virginia v. Tennessee*, 148 U.S. 503, 518 (1983).

[87] *New York v. O'Neill*, 359 U.S. 1, 6 (1959).

[88] 434 U.S. at 472–73.

[89] *Id.* at 454–56.

federal structure," as the Compact Clause only covered agreements "tending to the increase of political power in the States, which may encroach upon or interfere with the just supremacy of the United States."[90] This bar is extremely high. In all of the interstate compacts that the Court has reviewed, it has *never* found an interstate compact to encroach on federal power.[91] For that reason alone, it is unlikely that multi-state plans at issue here would trigger the Court's disapproval.

The Court in *Multistate Tax* listed the following indicia to evaluate whether an interstate agreement encroaches on federal power: if a compact (1) authorizes member states to exercise any powers they could not in its absence, (2) delegates sovereign authority, or (3) encroaches on the power of the United States with respect to foreign relations.[92] Multi-state plans under EPA's proposed rule do not exhibit these indicia.

Multi-state plans serve the same function as single-state plans and may even be submitted as one plan.[93] They do not "create" more authority for the states involved any more than if each of the member states submitted individual plans. It is true that the power sector is relatively unique because the sources operate in an interconnected grid system that is typically regional in scale. A multi-state plan that comprises a subset of states in a regional grid system could potentially exert economic influences on non-member states, but such pressure alone is unlikely to constitute federal encroachment.[94]

Additionally, a multi-state plan does not create any type of regulatory body with delegated authority that has greater powers than the sum of the member states acting individually or could bind member states in a way that would impact the federal structure. Even in *Multistate Tax*, the Court took no issue with member states empowering an administrative body to handle typically individualized tax legislative initiatives, noting that the individual states could have

---

[90] *Id.* at 471 (internal quotes omitted).

[91] See Lecture Note, *The Compact Clause and the Regional Greenhouse Gas Initiative*, 120 HARV. L. REV. 1958, 1962 (2007).

[92] *Id.* at 472–73. Some have argued that another relevant factor in determining if the Compact Clause covers an interstate compact is whether the compact affects the interests of non-compacting sister states, under the theory that adverse effects would impact the federal structure. *See* Raymond L. Gifford*, et al*, *supra* note 82. But in the two cases that mention the sister state interest doctrine, *United States Steel Corporation v. Multistate Tax Commission*, 434 U.S. 452 (1978), and *Northeast Bancorp, Inc. v. Board of Governors of Federal Reserve System*, 472 U.S. 159 (1985) (finding that two banking statutes in Massachusetts and Connecticut, which petitioners challenged as a cooperative effort between the two states to exclude non-New England banking organizations, did not violate the Compact Clause), the Court makes clear that mere pressure on sister states is insufficient "[u]nless that pressure transgresses the bounds of the Commerce Clause or the Privileges and Immunities Clause." *Multistate Tax*, 434 U.S. at 478. Therefore, unless the compact at issue *also* violates one of the other clauses, it would not pose a problem under the Compact Clause.

[93] *See* 79 Fed. Reg. at 34,838.

[94] *See Multistate Tax*, 434 U.S. at 473 (noting that while "[g]roup action in itself may be more influential than independent actions by the States," it did not enhance state power at the expense of the national government).

adopted the procedures on their own.[95] Under the proposed rule, states may meet EPA's emissions goals under individual plans as well as multi-state ones, albeit that the latter may capitalize on efficiencies. This is no different than what the Court permitted in *Multistate Tax*.

Finally, while the federal government is undoubtedly interested in climate policy on an international scale, interstate compacts that merely speak to federal *interests* do not necessarily encroach on federal *supremacy*.[96] The Court emphasized that the regulatory organization in *Multistate Tax* did not interfere or foreclose federal action, and therefore did not encroach on federal supremacy.[97] Moreover, even the fact that the member states were acting in concert to enhance their capacity to lobby for legislation did not constitute encroachment.[98] In comparison, multi-state plans are mere instruments for states to implement regulatory goals; they do not lend the member states any additional political power and certainly do not foreclose additional federal action, both from a domestic standpoint and if the United States were to enter into any international agreements on climate change.

In sum, for the multi-state plans to violate the Compact Clause, they would have to increase state power *at the expense of* federal supremacy. Ultimately, the primary difference between multi-state plans and single state plans is one of form, rather than function. The multi-state plans do not enhance state power any more than single state plans do. It is therefore unnecessary to receive congressional approval for these plans, which are merely one option that EPA has developed—an innovative and efficient method for additional emissions reduction that is well within the confines of the Agency's statutory authority. Indeed, it is the type of interstate cooperation that Congress envisioned and provided for when drafting the Clean Air Act.

Even though it is not our view that the Compact Clause argument is valid, the argument would be annulled if EPA were to make clear through a model rule the approvable elements of a multistate plan, including such plans intended to adopt multi-state mass-based allowance trading systems. In that case, multistate plans could not arguably be increasing political power in the States, or "encroach[ing] upon or interfere[ing] with the just supremacy of the United States," indeed they would be in furtherance of the Clean Air Act's directives, and the federal government's policy on pollution control.

III. EPA's rate-based targets are reasonable, indeed some of the assumptions underlying the supporting BSER analysis are overly conservative.

EPA developed state targets using a BSER that includes measures that are adequately demonstrated, and achieve significant CO_2 emissions reductions from existing subpart Da and KKKK designated facilities. EPA provides the states with a great deal of flexibility, but its

---

[95] *Id.*

[96] *See id.* at 479 n.33 ("Absent a threat of encroachment or interference through enhanced state power, the existence of a federal interest is irrelevant.").

[97] *See id.*

[98] *See id.*

BSER estimates reasonable rather than maximum practicable emissions reductions available from each measure included in the four building blocks.[99] Due to conservative assumptions, some measures within the building blocks are available to a greater extent than EPA determined, and additional measures, which EPA did not include in the building blocks at all, are available at reasonable cost. We describe ways to strengthen the building blocks below.

a. Building block 1 is reasonable, but it should be strengthened.

As currently configured by EPA, building block 1 is solely focused on Heat Rate Improvements ("HRI"). However, HRI is just one element of a larger group of measures we refer to as Unit Specific Measures ("USM") – those control options that can be applied directly to an affected source to reduce CO_2 emissions, including (in addition to HRI), retrofit carbon capture and sequestration ("CCS"), natural gas co-firing in coal units, and affected unit retirements. Reconceiving building block 1 as a bundle of potentially available Unit Specific Measures, and determining the potential CO_2 reductions available state by state not only achieves the maximum practicable reductions directly from affected sources, but also even satisfies EPA's stated interest that the building blocks be "broadly applicable"[100] to existing fossil-fueled power plants. For example, even if one particular option cannot be applied to a specific unit or group of units within a state, the target rate would be supported by other options within the basket. For example, a Massachusetts-based plant might not have access to enhanced oil recovery ("EOR") sequestration and so CCS might not be a reasonable option for use in deriving the USM building block 1 portion of Massachusetts' target rate. But co-firing with natural gas is potentially available to existing designated facilities in Massachusetts. While EPA's proposed approach to the BSER nowhere precludes states from doing this analysis as they plan their compliance, the state-specific targets can be strengthened if they are based on a BSER that more accurately reflects the suite of compliance options available to reduce CO_2 directly from existing affected sources.

This "bundling" approach to building block 1 moreover is consistent with the approach EPA is already taking in building block 3 (renewables).[101] And it is consistent with EPA's longstanding regulations – as EPA appreciated in 1975, section 111(d) performance standards or "guidelines" necessarily reflect differences in controls based on location.[102] EPA in the CPP

---

[99] 79 Fed. Reg. at 34,859.

[100] 79 Fed. Reg. at 34,905 n.74 (noting that for "inclusion in the building blocks, the EPA considered only those emission abatement measures that are technically feasible and broadly applicable, and can provide reductions in CO[2] emissions from affected EGUs at reasonable cost"). We note that the phrase "broadly available" is not the statutory test or even a factor in the statutory test for determining the "best system of emissions reduction." See 42 U.S.C. §7411(a)(1). Nor is it found in the relevant case law.

[101] EPA adopted a broad interpretation of RE generation to include any non-fossil renewable type, with the exception of generation from existing hydroelectric power facilities. U.S. EPA, *Technical Support Document: GHG Abatement Measures*, at 4-5, Docket ID No. EPA-HQ-OAR-2013-0602-0437 (June 2014) [hereinafter *GHG Abatement Measures TSD*].

[102] 40 Fed. Reg. 53,340, 53,341 (Nov. 15, 1975).

proposal describes building block 3 renewables as including a portfolio of particular technologies showing clear dominance in specific regions:

> North Central and South Central regions have strong on-shore wind resource potential. The East Central and Southeast regions show moderate to strong resources in both biopower and rooftop PV potential. The West has notable potential in geothermal (hydrothermal) power and concentrating solar power, in addition to potential for increased hydropower generation. The Northeast has strong resources in off-shore wind and moderate biopower and solar resources available.[103]

By bundling these options together as "renewables" and not as separate building blocks for geothermal, off-shore wind, on-shore wind, landfill gas combustors, etc., EPA avoids having to decide whether a single technology option is 'broadly available' (as the Agency puts it) for application at all affected units. Regardless whether 'broad availability' is in fact a relevant factor in EPA's determination as to what constitutes the BSER for existing sources (and we assert it is not), it is inconsistent with the position EPA has taken on renewables. EPA's building block 3 category "renewables" contains a number of technologies that the Agency includes in the BSER determination are *not* everywhere available.

At a minimum, building block 1 should include the following components:

- Heat Rate Improvements at Affected Units;
- Natural Gas Co-firing in Affected Coal Units;
- Retirements of Affected Sources, after 2012 and as of the Date of State Plan Submittal; and
- Carbon Capture and Sequestration Retrofits.

i. **Heat rate improvements.** In a simplified analysis of HRI, EPA estimates the contribution from a 6 percent heat rate improvement to be about 97 million metric tons per year.[104]

ii. **Natural gas co-firing in coal plants is a unit specific CO_2 control measure that should be included in building block 1.**

EPA identifies redispatch of existing natural gas combined cycle generation ("NGCC") as the most cost-effective strategy to incorporate the use of lower carbon-emitting natural gas into the BSER and state goal calculation process. But, the Agency declines to identify natural gas *co-firing* in coal boilers as BSER or to make it part of the state goal calculation methodology. EPA asked for comment on ways that the building block analysis could be expanded, including natural gas co-firing in existing coal-fired boilers,[105] and spotlighted this request in the recent

[103] *GHG Abatement Measures TSD*, at 4-12.

[104] *Id.* at 2-39.

[105] 79 Fed. Reg. 34,876.

NODA.[106] In requesting comment, EPA acknowledged that there might be other important considerations that can shape the relationship of the BSER to natural gas consumption, such as the flexibility that co-firing could provide.[107]

Specifically, EPA requests comment on the additional suite of potential benefits from gas co-firing that could justify inclusion of co-firing in the BSER and state goal calculation process, asserting that:[108]

> 1. Co-firing can reduce emissions of nitrogen oxides (NOx); sulfur dioxide (SO2); particulate matter; and hazardous air pollutants, including mercury. Co-firing could also reduce some portion of the costs related to control of these pollutants (depending on the extent of co-firing).
>
> 2. Co-firing might also provide additional operational flexibility, particularly for coal-fired units that are regularly used at less than full load or that cycle regularly. Co-firing may allow units to ramp up and down more quickly, which could give a company the opportunity to take advantage of low fuel prices, when they occur, to achieve cost savings.
>
> 3. Co-firing could allow additional time for implementation of strategies in state plans that have a lengthier implementation timeframe, such as building up a robust energy efficiency program.
>
> 4. Further, co-firing could provide an opportunity to achieve emission reductions at existing higher emitting units with relatively low levels of capital investment, thereby addressing companies' concerns about stranded assets. It should also be noted that utilities continue to announce conversions or plans to convert coal-fired steam boilers to natural gas.

EPA concludes:

> We are requesting comment on these aspects of the costs and potential benefits (or offsetting cost advantages) of co-firing natural gas at existing coal plants, to the extent they were not considered or presented for comment in the proposed rule, along with any other additional costs and potential benefits of such co-firing that could be considered in goal setting. In addition, we are requesting comment on other factors or variables that might affect the decision to use natural gas in co-firing at a particular unit (e.g., type, age, or size of a boiler), as well as factors that could limit the amount of co-firing that could be done. For units currently co-firing with natural gas, we request comment on the benefits experienced and the

---

[106] 79 Fed. Reg. 64,546.

[107] 79 Fed. Reg. 34,875 and 79 Fed. Reg. 64,550.

[108] 79 Fed. Reg. at 64,550-51.

extent to which co-firing is being done.[109]

Yet, EPA declined to identify natural gas co-firing as BSER or to make it part of the state goal calculation methodology solely on the basis that its costs were relatively higher than redispatch of existing gas facilities in achieving carbon dioxide reductions ($/ton CO_2).[110] In so doing, however, EPA failed to take into account the requisite statutory factors in determining BSER and identifying which measures should be included in the state goal calculation methodology.

EPA has proposed to limit the state goal calculation from onsite modifications to fossil steam units in building block 1 to heat rate improvements only. Further, EPA declined to identify natural gas co-firing as part of the state goal calculation under building block 2 on the basis that:

> Switching from coal to gas is a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements and redispatch of generation supply to other existing capacity with lower CO_2 emission rates. Moreover, we concluded that coal-to-gas conversion of an existing boiler is less efficient than constructing a new natural gas combined cycle (NGCC) turbine in its place.[111]

To the contrary, CATF recommends that the BSER for existing fossil steam units should include co-firing with natural gas, because this well-demonstrated measure would yield significantly greater emission reductions directly at the affected unit, than would EPA's proposed heat rate-only approach while satisfying the other statutory factors for BSER. Rejecting gas co-firing on the sole basis that its $/ton cost of carbon dioxide reduced is likely to be relatively higher than that for other strategies fails to appropriately characterize the full benefits of gas co-firing or reflect full consideration of the statutory BSER factors.[112] Careful examination of these factors demonstrates gas co-firing fits the statutory criteria for BSER.[113]

---

[109] 79 Fed. Reg. 45,550-51.

[110] 79 Fed. Reg. 34,875 and *GHG Abatement Measures TSD*, at 6-9.

[111] *GHG Abatement Measures TSD*, at 6-9. *See also*, 79 Fed. Reg. at 34,875.

[112] Section 111(a) explicitly instructs EPA to balance multiple concerns when promulgating a NSPS:

> [A] standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which *(taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements)* the Administrator determines has been adequately demonstrated.

[113] EPA specifically requested comment on ways that building block 2 could be expanded to include gas co-firing. However, CATF observes that gas co-firing – as a unit-specific control measure, more properly belongs within building block 1 as a strategy that can be accomplished by modifications at an existing fossil steam unit.

1. Co-firing coal boilers with natural gas is adequately demonstrated, technically feasible, and available.

The technology for a fossil steam unit to co-fire with natural gas is well demonstrated and commercially available, as EPA acknowledges.[114] In October, SNL Energy, which tracks unit fuel conversions, found that nearly 12,000 MW of coal-fired capacity in the U.S. has converted or is slated to convert to alternative fuel sources between 2011 and 2023.[115] According to SNL Energy data, of the approximately 11,288 MW of coal capacity planned to be converted, 10,894 MW is being converted to gas-fired generation.[116] SNL Energy found that the number of coal-to-gas conversions is expected to increase going forward as generators retrofit older coal units or build new gas generation on sites where coal units have been dismantled.[117] The SNL Energy maps in Figure 2 illustrate the planned gas unit conversions and plans for co-firing through 2022.[118]

---

[114] 79 Fed. Reg. at 34,982 ("conversion to . . . natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates"); 79 Fed. Reg. at 64,550-51. *See also GHG Abatement Measures TSD*, at 6-1, 6-2.

[115] Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3)

[116] *Id.*

[117] *Id*.

[118] *Id.*

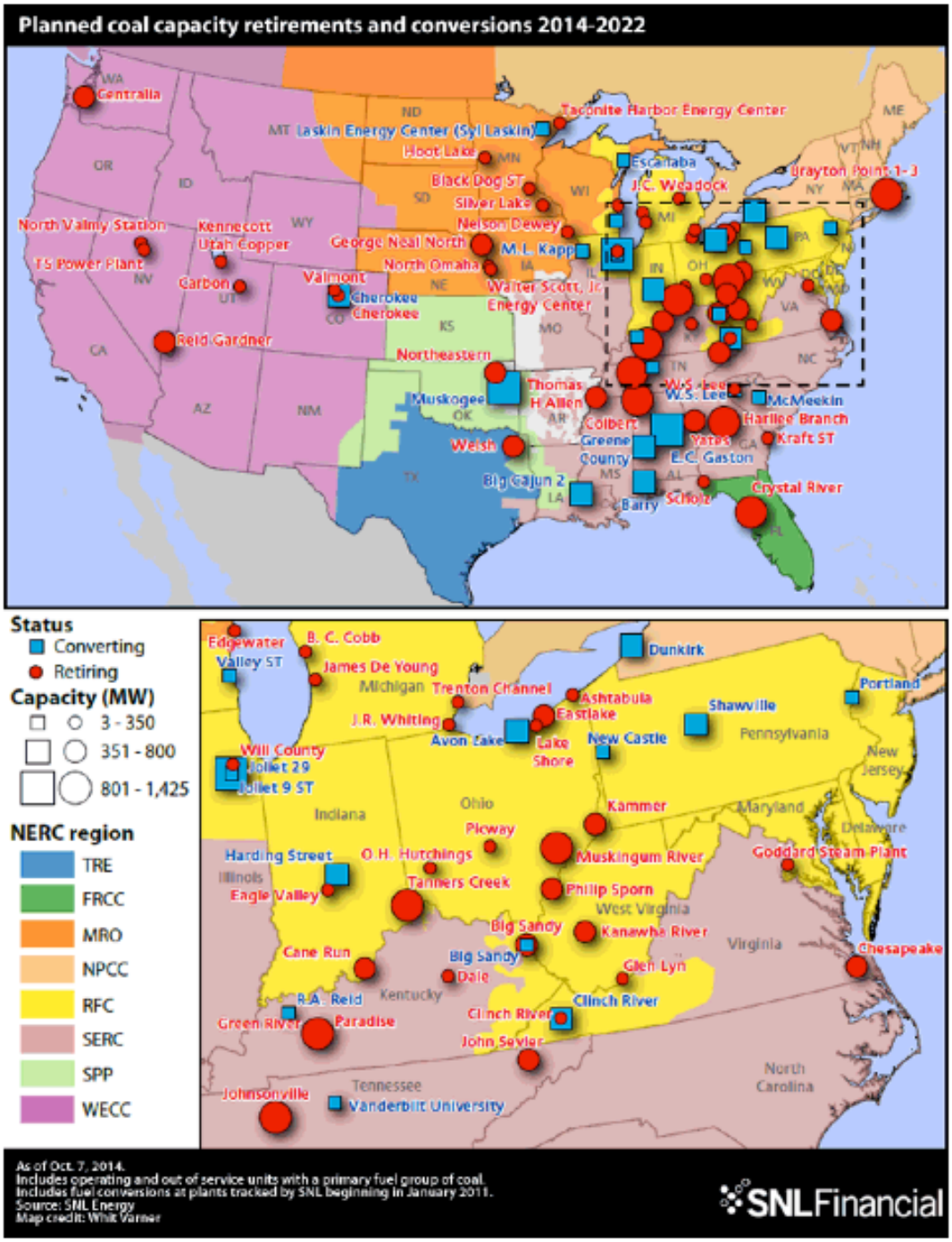


Figure 2: Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3) (showing planned coal capacity and conversions between 2014 and 2022)

In fact, electric utilities have been increasingly co-firing natural gas in coal boilers for at least a decade.[119] The electric power industry is undertaking gas co-firing and full coal-to-gas

[119] *See, e.g.*, Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp (Possum Point Power Station "Units 3 & 4 are fired using natural gas but were converted from coal in May of 2003. Unit 3 generates 96 MW and Unit 4 generates 220 MW.").

conversions at a wide variety of units, including very old EGUs,[120] baseload power plants,[121] and facilities that are over thirty miles from natural gas pipelines.[122] As further evidence of the technical feasibility of gas co-firing, several engineering firms have developed literature outlining economic and technical considerations for utilities that are considering such projects.[123] A recent Black & Veatch paper describes the process for converting a coal-fired unit to run entirely on natural gas.[124]

Although there are unit-specific concerns and costs that may affect decisions about co-firing a given unit, CATF is unaware of any existing coal units for which co-firing with natural gas is technologically infeasible.

2. Gas co-firing and/or conversion would result in greater carbon dioxide emission reductions along with significant reductions of other pollutants and air toxics.

Unlike EPA's proposed heat rate-only approach, co-firing natural gas has very significant potential for reducing the carbon dioxide emissions from coal boilers —a critical factor in the BSER analysis. For example, EPA's analysis of gas co-firing concluded that a reconstructed

---

[120] The Blount Street power plant was first built in 1903 and converted to burn natural gas in 2010. Thomas Content, *MG&E stops burning coal in Madison plant*, MILWAUKEE J. SUN (Mar. 18, 2010), *available at*: http://www.jsonline.com/business/88508257.html.

[121] Darren Epps, *Alabama Power switching to natural gas from coal at 4 Gaston plant units*, SNL (Jan. 17, 2014), *available at*: https://www.snl.com/InteractiveX/Article.aspx?id=26566141.(reporting Alabama Power's application to convert 4 units, each with a capacity of about 250 MW, to burn natural gas); Colorado Department of Regulatory Agencies, Powerpoint, *Colorado's electric grid and the role of base load and "peaker" electric generating units*, *available at*: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=390881&p_session_id= (classifying the 352-Mw Cherokee unit 4 as a baseload plant).

[122] Xcel Energy, Cherokee Repowering & Natural Gas Pipeline Projects, *available at*: http://www.xcelenergycherokeepipeline.com ("The Cherokee Natural Gas Pipeline Project has been completed."); Thomas Spencer, *Alabama Power to connect Shelby plant to natural gas line*, THE BIRMINGHAM NEWS, *available at*: http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html(citing an Alabama Power spokesperson for information that the coal-to-gas conversion project at the Gaston Steam Plant will involve building a gas pipeline to tie into the Transcontinental pipeline, which runs across Alabama about 30 miles south of the plant).

[123] *See generally* Babcock & Wilcox, *Natural Gas Conversions of Existing Coal-Fired Boilers* (2010) available at: http://www.babcock.com/library/documents/ms-14.pdf("This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision."); Black & Veatch, *Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch* (2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch("This paper explores several technically feasible options available on the current market" for retrofitting coal-fired units, including full conversion to natural gas).

[124] Black & Veatch, A *Case Study on Coal to Natural Gas Fuel Switch* (Dec. 12, 2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

utility boiler firing 100 percent natural gas would yield a 40 percent reduction in carbon dioxide emissions relative to 100 percent coal firing.[125]

EPA also must consider the pollution reduction co-benefits that would result from co-firing a coal boiler with natural gas.[126] For example, EPA estimated that converting to 100 percent natural gas would significantly reduce a utility boiler's emissions of SO_2, NOx, and PM2.5.[127] And partial co-firing would reduce these pollutants in amounts directly related to the percent of gas being co-fired. These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between $67 to $150/MWh—a factor of at least two times the costs associated with co-firing, as noted below.[128] By promulgating a standard that takes advantage of these pollution reduction co-benefits, EPA can greatly reduce the health burdens on the communities living near these sources.

3. The costs of natural gas co-firing and/or conversion are reasonable and can be further constrained through prudent application in the state goal calculation methodology.

EPA rejected natural gas co-firing because it found that co-firing represents "an inefficient way to generate electricity compared to use of an NGCC" and that CO_2 reductions from this option were "relatively costly."[129] EPA estimated the costs of CO_2 avoided from natural gas co-firing to be $83 per metric ton.[130] In terms of generation, EPA estimated that co-firing with natural gas would increase the fuel costs of an EGU by approximately $30/MWh (three cents per kWh), increase capital costs by $5/MWh, while it would reduce fixed operating costs by 33 percent and variable operating costs by 25 percent.[131] The net costs may be higher than other options EPA has considered, but they are significantly lower than the benefits associated with criteria pollutant reductions from conversion—which as noted above, are approximately $67-140/MWh. Adding in the benefits of reduced CO_2 pollution (e.g., consistent

---

[125] *GHG Abatement Measures TSD*, at 6-6, Table 6-1.

[126] *Cf.* 42 U.S.C. §7411(a)(1) (EPA is to take into account nonair quality health and environmental impact, which we understand include health and environmental benefits due to reductions in other air pollutants beyond the regulated pollutant).

[127] *GHG Abatement Measures TSD*, at 6-6, Table 6-2.

[128] *Id.* at 6-7, Table 6-3. Even given a steep 7 percent discount rate, EPA estimated the health benefits of reducing co- pollutants through natural gas conversion to be between $61/MWh and $140/.

[129] *Id.* at 6-9; 79 Fed. Reg. at 34857.

[130] 79 Fed. Reg. 34857.

[131] *GHG Abatement Measures TSD*, at 6-4. According to EIA's most recent estimates of generation costs, fixed O&M costs for an advanced pulverized coal EGU are approximately $31-38/kW-yr (equivalent to approximately $5/MWh) and variable O&M costs are approximately $4.50/MWh. *See* EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013), *available at*: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

with the Social Cost of Carbon) would only increase the obvious value of identifying gas co-firing as a BSER. The fact that so many co-firing and conversion projects have been undertaken or announced shows that the costs are eminently reasonable, certainly as compared with the levels of costs courts have suggested constrain new source performance standard setting under section 111.[132]

Gas co-firing has emerged as a means of complying with emission standards precisely because it is sometimes the most cost reasonable strategy.[133] Several coal-fired units are co-firing with natural gas because it is the units' most economical option for complying with other emission limitations.[134] The cost of converting to natural gas fuel depends on whether the unit was originally designed to be capable of burning natural gas. The cost of fuel-switching in boilers is minimal for units that are already designed to burn gas, but even the cost of more extensive retrofits is still moderate.[135] Even where retrofit costs are significant, the conversion to natural gas is eminently cost reasonable and can be achieved in a manner that enables electricity consumers actually to save money.[136]

---

[132] EPA must "consider" cost in setting section 111(d) existing source performance standards. While no court has opined on an acceptable cost level for existing source standards, courts have determined that costs of *new* source performance standards under section 111 must not be "exorbitant," *see Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive," *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").

[133] Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3).

[134] Georgia Power Company, *2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6* at 1-18, *available at*: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145981("Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost- effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel."); *see also id.* at 1-11 (requesting favorable amortization of "approximately $14 million of Plant Yates Units 6 and 7 environmental construction work in progress"). Conversion to natural gas is likely to be a cost- effective compliance option for any facility with limited planned service hours. Black & Veatch, *A Case Study on Coal to Natural Gas Fuel Switch* at 7, Table 7.

[135] Ameren Missouri, 2014 Integrated Resource Plan at 4-18, *available at*: https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp.
Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

[136] *See e.g.* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that

For some units, building a pipeline is a cost associated with conversion to natural gas. EPA's cost estimates assumed that a unit converting to natural gas would need to build a 50-mile pipeline at a cost of $50 million.[137] EPA estimated pipeline construction would contribute $100/kW to the capital costs of a 500 MW unit, while capital costs as a whole represented only one-seventh of the cost impact of natural gas conversion.[138] EPA's analysis shows that even building a long pipeline is generally a relatively small part of the cost of converting a reconstructed unit to burn natural gas. Consequently, units can undergo conversion at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. For most units, however, the cost of building a pipeline is likely to be less than EPA assumed. This is because the median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[139]

In calculating costs, EPA also used an average national natural gas price figure. In fact, due to the shale gas development boom, the price of natural gas now varies by region. In particular, fossil units with nearby access to plentiful shale gas supplies may be able to take advantage of relatively lower natural gas prices than EPA assumed. For example, gas customers in the Marcellus shale region (Pennsylvania, West Virginia, and eastern Ohio), now typically pay much less than the Henry Hub gas price, the traditional source of gas price information.[140] As a result, co-firing natural gas in coal units located near the Marcellus Shale e.g., West Virginia and Kentucky, could be significantly less expensive than EPA assumed. In fact, of the ten states that EPA's CPP goal data computation spreadsheet shows are able to displace less than 10 percent of their coal generation with existing NGCC generation, all but Missouri are located in or adjacent to booming shale gas basin: Marcellus shale: (Kentucky, Indiana, Ohio, Pennsylvania, Maryland, Tennessee) and Niobrara shale: (Wyoming, Nebraska). Moreover, these are the very states that received less stringent state emission targets because they had little underutilized existing NGCC capacity under building block 2.

To the extent that EPA continues to be concerned with upward pressure on natural gas

---

the cost of the conversion would be $62 million and "rates for electric customers will go down by [0.31]%, for a net savings of $10.2 million in 2016").

[137] *GHG Abatement Measures TSD*, at 6-4.

[138] *Id.* at 6-4, 6-5. In EPA's estimation, increased fuel costs were responsible for most of the cost of natural gas conversion. *Id.*

[139] *See* U.S. EPA, Power Sector Modeling Platform v.5.13 at Table 522 "Cost of Building Pipelines to Coal Plants" *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles; greater than the median distance because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.

[140] U.S. EIA, "Some Appalachian natural gas spot prices are well below the Henry Hub national benchmark" (Oct. 15, 2014) available at: http://www.eia.gov/todayinenergy/detail.cfm?id=18391. *See also*, William Pentland, "R.I.P. Henry Hub? Marcellus Shale Shifts Geography Of Natural Gas Markets," FORBES (Oct. 16, 2014) http://www.forbes.com/sites/williampentland/2014/10/16/r-i-p-henry-hub-marcellus-shale-shifts-geography-of-natural-gas-markets/.

prices that could potentially occur due to increased gas use through co-firing, EPA could limit the application of co-firing in the goal-setting process to these states that have little or no potential to displace coal generation with existing natural gas combined cycle units under building block 2.[141] Using gas co-firing potential in these states' goal calculation would also serve to mitigate equity concerns expressed by stakeholders that building block 2 has little or no effect on the states with large amounts of coal-fired generation and limited excess existing NGCC capacity.[142]

4. Including gas co-firing in the BSER determination and state goal calculation methodology would deliver enhanced non-air health and environmental impacts.

EPA impermissibly fails to consider the non-air quality health and environmental impacts of not including gas co-firing as BSER.[143] If EPA had properly considered this factor,[144] the Agency would have to have recognized that co-firing with natural gas at existing coal units, and especially conversion of coal units to combust 100 percent natural gas, would have far greater non-air health and environmental benefits than its proposed heat rate-only approach. Specifically, co-firing and/or conversion would reduce or eliminate the unit's production of coal combustion waste ("CCW"). CCW is an industrial waste that contains a range of toxic substances, including arsenic, selenium, and cadmium. Carcinogens and toxic chemicals from coal ash can leach into drinking water supplies and accumulate in the fish we eat.[145] EPA has proposed regulating the disposal of coal ash for the first time,[146] but even promulgation of a robust CCW rule cannot be completely effective in protecting communities from the dangers of coal ash. Conversion to natural gas firing also reduces on-site water quality impacts.[147]

---

[141] *See* discussion at 79 Fed. Reg. at 64,546, 49.

[142] *Id.*

[143] *Sierra Club*, 657 F.2d at 323 ("the agency must consider all of the relevant factors and demonstrate a reasonable connection between the facts on the record and the resulting policy choice").

[144] *Sierra Club*, 657 F.2d at 346, n.175.

[145] U.S. EPA, *Human and Ecological Risk Assessment of Coal Combustion Wastes* (draft) (Apr. 2010), *available at*: http://earthjustice.org/sites/default/files/library/reports/epa-coal-combustion-waste-risk-assessment.pdf. One of the study's conclusions was that managing coal ash in unlined or clay-lined waste management units results in up to 1 in 50 excess cancer risks.

[146] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities; Proposed Rule, 75 Fed. Reg. 35128 (June 21, 2010).

[147] As the Wisconsin Public Service Commission observed in approving the conversion of Valley Power Plant, "Converting the plant from coal to natural gas would eliminate some discharge sources and reduce wastewater treatment requirements. Conversion would eliminate coal pile runoff, yard runoff, ash transport water, and equipment wash wastewaters that convey coal or ash, thereby removing a potential source of mercury." Public Service Commission of Wisconsin, *Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility* at 19 (Mar. 17, 2014) , *available at*: http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=200566.

5. Gas co-firing can help coal generators manage system energy requirements so that potential adverse impacts on the power sector can be mitigated.

The SNL Energy analysis cited above demonstrates that gas co-firing is a cost-reasonable response to the energy, market, and regulatory environment faced by generators with coal units. The data shows that numerous natural gas repowering and co-firing projects are occurring today, most without regard to any direct requirement to reduce CO_2 emissions.[148] Dramatically lower natural gas prices and increased development of shale gas resources have made these projects even more economic.[149] The Babock and Wilcox and Black and Veatch engineering analyses demonstrate that co-firing can reduce maintenance requirements and increase operational flexibility by allowing the coal-fired plants to cycle (increase an decrease their output) more readily to respond to changes in load demand. These studies demonstrate that many companies are using natural gas conversion or co-firing as low cost mechanisms to reduce emissions of conventional and hazardous air pollutants to comply with the requirements of the Mercury and Air Toxics Rule, the Cross-State Air Pollution Rule, Regional Haze requirements, and other environmental requirements. Indeed, some of these projects have allowed companies to continue to rely on coal-fired facilities that would otherwise have retired.[150]

Some stakeholders have asserted that additional reliance on natural gas could create reliability concerns based on insufficient gas supply or gas delivery infrastructure. We address those concerns in our discussion of building block 2. However, the incremental effect of including additional gas demand via co-firing could be mitigated by applying co-firing in the state goal computation only in states with little or no potential to reduce emissions through redispatch of existing natural gas units. EPA should undertake an analysis of the natural gas supply and infrastructure to identify the potential for gas co-firing both at units that currently have natural gas supply and units in such states for which natural gas pipeline infrastructure could be constructed to supply the natural gas necessary for co-firing.

A careful weighing of the statutory criteria and other considerations EPA raised in the CPP proposal and NODA should lead EPA to the conclusion that gas co-firing should be included in the BSER analysis and state goal calculation formula as a unit specific measure under building block 1. Excluding this option on the sole basis that its cost per ton of CO_2 avoided is higher than for heat rate improvements is an impermissibly narrow basis for decision – and indeed cuts against the argument that a variety of measures (with varying costs) are available to states for use in compliance. In sum, EPA has ample basis to include increased natural gas co-firing and conversion measures to achieve CO_2 emissions reductions in its state target setting exercise. Inclusion of gas co-firing in building block 1 would direct greater

---

[148] Michael Niven and Neil Powell, "Coal unit retirements, conversions continue to sweep through power sector," SNL Data Dispatch (Oct. 14, 2014) (Ex. 3).

[149] *Id. See also* Babcock & Wilcox, *Natural Gas Conversions of Existing Coal-Fired Boilers* (2010); Black & Veatch, *A Case Study on Coal to Natural Gas Fuel Switch* (Dec 12, 2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

[150] Michael Niven and Neil Powell *supra* note 148 (Ex. 3); *See also* text accompanying footnotes 10 to 19 *infra*.

reductions than unit heat rate improvements alone, and at reasonable cost. Moreover, inclusion of gas co-firing will have important non-air health and environmental benefits and reduce dangerous co-pollutant emissions.

iii. Affected source shutdowns/retirements as of the date of state plan submission should be included in target rates for each state.

Shut down or retirement of an existing EGU yields permanent "emissions limitations" or "emissions reductions"[151] at the existing unit – indeed it completely eliminates the unit's pollution emissions.[152] And the "best" system of emissions reduction surely must encompass actions that completely eliminate emissions. Shutdowns or retirements of existing EGUs therefore clearly should be considered a component of the BSER.

U.S. coal-fired power plants are shutting down or "retiring" at an accelerated rate due to a combination of lower natural gas prices, higher coal prices, low electricity demand, increased penetration of renewable energy sources and environmental regulations.[153] In 2012 alone, 10.2 GW of coal-fired capacity was retired.[154] In August 2014, the U.S. Government Accountability Office ("GAO") reviewed data from SNL Financial and determined that power companies retired or planned to retire about 13 percent of coal-fired net summer generating capacity (42,192 MW) at 238 units from 2012 to 2025.[155] Regional Transmission Organization officials reported to GAO that an additional 7,000 MW from 46 generating units also might be retired from 2012 to 2015.[156] About three quarters of these retirements are expected to occur before 2016.[157]

---

[151] 42 U.S.C. §7411(a)(1).

[152] EPA has recognized this in enforcement settings, including shut down as an "emissions reduction and control" requirement to comply with the Clean Air Act. *See, e.g.* Consent Decree, *United States v. Tampa Electric Co.,* Civ. No. 99-2524 (M.D. Fla. 2004) at 7-8 (prescribing permanent shut-down amongst "emissions reductions and controls"), http://www2.epa.gov/sites/production/files/documents/tecocd.pdf.

[153] *See* U.S. EIA, *Annual Energy Outlook 2014 with projections to 2040*, at IF-34 (Apr. 2014), *available at*: http://www.eia.gov/forecasts/aeo/.

[154] U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503.

[155] U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 15 (Aug. 2014), *available at*: http://www.gao.gov/assets/670/665325.pdf. *See also* Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL FINANCIAL, Oct. 14, 2014, *available at*: https://www.snl.com/interactivex/article.aspx?id=29431641&Printable=1&KPLT=6 (including tables of planned coal unit retirements).

[156] *Id.*

[157] U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 17 (Aug. 2014), available at: http://www.gao.gov/assets/670/665325.pdf.

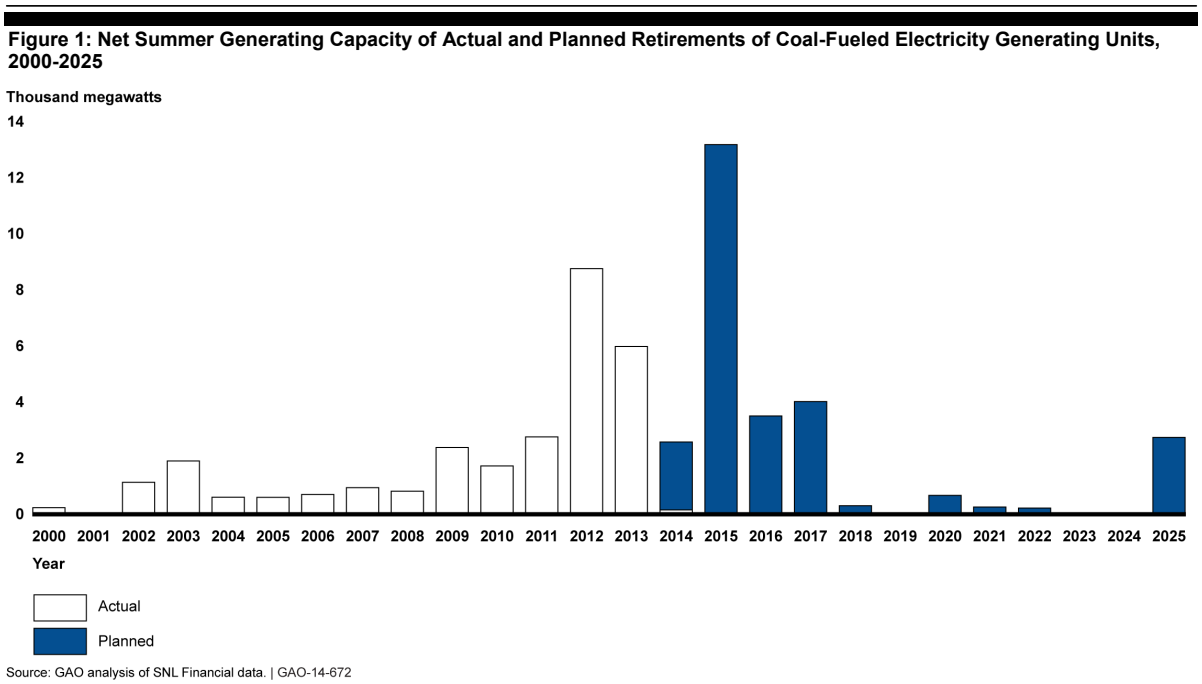


Figure 3: U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 18 (Aug. 2014) (showing the summer net generating capacity of actual and planned retirements of coal-fired EGUs, 2000-2025).

The U.S. Energy Information Agency projects that 60 GW of capacity will retire by 2020, with about 40 GW occurring after 2012, and nearly all of that already reported on Form EIA-860.[158] Figure 4 below also shows that nearly all of those retirements are projected to occur by 2016, the deadline for state plan submittal under EPA's CPP rule.

However, EPA's proposed state targets do not reflect *any* of the approximately 60 GW of projected coal-fired power plant retirements projected to occur from 2012 through the 2016 deadline for state plan submittal—even those that *already* have occurred since 2012. EPA therefore has left significant CO_2 emissions reduction potential on the table in its proposed target setting process. For example, in the RGGI states, the regional carbon rate is reduced by over 56 lb./MWh if affected coal units that reach the average retirement age are actually shut down by 2020. [159]

[158] U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503.

[159] Comment submitted by Kelly Speakes-Backman, Chair, Regional Greenhouse Gas Initiative (RGGI), Doc ID: EPA-HQ-OAR-2013-0602-22395, at 15 (Nov. 5, 2014).

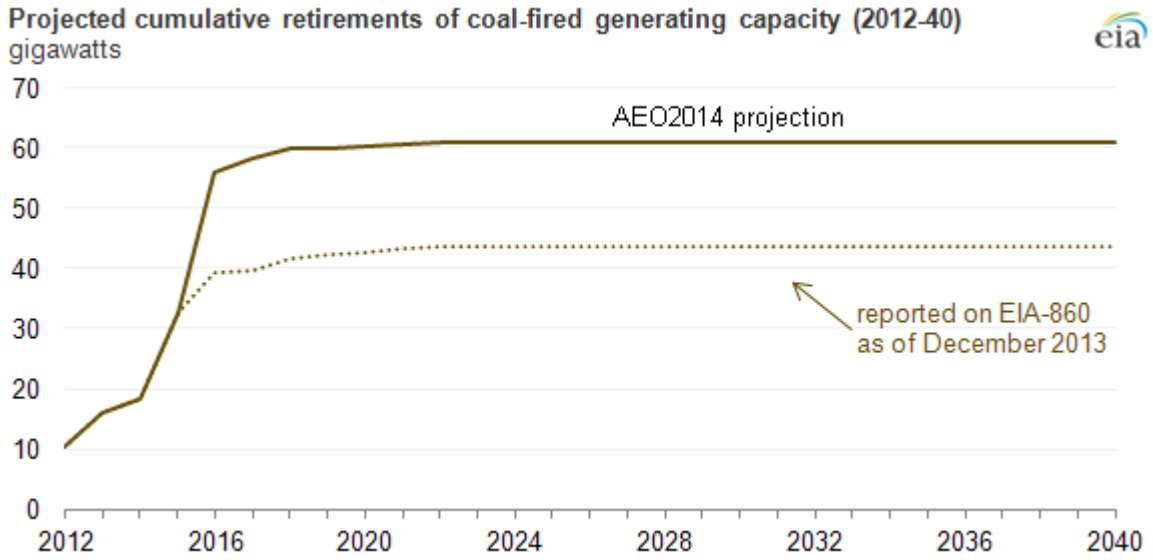


Figure 4: U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503 (showing projected cumulative retirements of coal-fired generating capacity from 2012 to 2040).

EPA's BSER must accurately reflect expected control options,[160] which in this case clearly include affected source retirements since 2012, and retirements already planned to occur by the date of plan submittal. If the BSER were adjusted to include retirements that occur before the date a state submits its CPP compliance plan, that would not only more accurately reflect the CO_2 emissions reductions available from the affected sources, but also would provide states with an incentive to submit their CPP compliance plans as early as is practicable.

iv. Carbon capture and sequestration retrofits are available as unit specific measures under building block 1.

EPA identifies 17 states with enhanced oil recovery ("EOR") sequestration potential, in the assumptions it uses in the IPM modeling in support of the proposed rule.[161] Those states are - Alabama, Arkansas, California, Colorado, Florida, Illinois, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.[162] As more fully described below, modeling performed at CATF's direction by Charles River Associates, demonstrates that when more accurate and updated assumptions about CCS. CCS retrofit can result in near-zero CO_2 emissions from designated facilities and a detailed analysis of CCS retrofit technology is provided in Appendix B. CRA incorporated updated assumptions about CCS with EPA's other assumptions, affected sources in 9 of those states are projected to

[160] *Sierra Club v. Costle*, 657 F.2d 298, 332 (D.C. Cir. 1981) (standards should accurately reflect reality).

[161] U.S. EPA, *EPA's Power Sector Modeling Platform*, at Table 6-2, (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

[162] *Id.* These states have over 13 gigatons of EOR storage capacity.

apply CCS-EOR as a compliance pathway. That would yield reduced CO_2 emissions of nearly 85 million metric tons per year, or about 14 percent of the *total* annual reductions achieved nationwide in 2030 by the CPP, as compared to 2012 emissions.

EPA notes many advantages to CCS technologies that we agree are important:

- CCS can reduce CO_2 emissions 90 percent with full capture, and lower levels with partial capture. EPA found that partial CCS was adequately demonstrated and a BSER for new fossil fuel-fired steam EGUs and IGCC plants.[163]

- CCS retrofits are demonstrated at existing EGUs. Furthermore, carbon capture retrofits and EOR sequestration is already in use at Plant Barry, and at SaskPower's Boundary Dam facility, and is soon to be installed at NRG's W. A. Parish plant.[164]

Yet EPA also determines not to include any CCS or even partial capture (less than 90 percent capture) retrofits as an element of the BSER for existing power plants. EPA asserts that not all existing sources are located in close proximity to CO_2 storage or pipelines.[165] The Agency cites "technical challenges" with retrofit CCS, asserting the unremarkable proposition that integrating capture technology into an existing facility presents more challenges than building it into a new source, and that some sources may lack available land or space to host the capture equipment.[166] EPA also claims that cost and non-specific reliability concerns preclude the including of retrofit CCS in the target setting process.[167] These statements seemingly reflect the unrealistic assumption that including *some* CCS in the target setting equation in the rule would amount to a national mandate to apply CCS retrofits to *all* designating facilities, which of course is not the case for *any* of the BSER technologies EPA has included in the target setting metric.[168]

There are however, compelling reasons why available retrofit CCS technologies should be included in BSER, and in the goal-setting exercise for certain states. First, existing plants actually have a capital advantage over new plants with respect to CCS, because the investment to build an existing plant has already been made. So the investment for CCS retrofits at an existing plant is just for costs of the control equipment. In contrast, a new plant with CCS requires capital for both the plant and the CCS equipment.

---

[163] 79 Fed. Reg. at 34,856.

[164] *Id.* at 34,876.

[165] *GHG Abatement Measures TSD*, at 7-5 (contrasting the Boundary Dam, Parish, and Plant Barry projects with the norm for existing affected sources in that these projects are close to storage options, and relying again on the non-statutory concept that any element of the BSER must be "broadly available" for existing sources as a basis to reject including CCS).

[166] *Id.*; *see also* 79 Fed. Reg. at 34,876. The proposition that it is 'more challenging' to add pollution control to an existing source than to design it into a new source, is hardly novel – indeed it is nearly always true.

[167] *GHG Abatement Measures TSD*, at 7-5; 79 Fed. Reg. at 34,876.

[168] Taken to its logical conclusion. EPA's fabricated "broad applicability" criterion (with which we disagree) for existing source BSER reflects the assumption that selecting a technology for inclusion in BSER creates a national mandate to apply the technology, which is not consistent with the statutory frame.

Second, depending on the price the plant operator gets for selling the CO_2 to an EOR operator, the dispatch costs for the plant with a CO_2 capture retrofit can be less than the dispatch costs for the same existing plant prior to retrofit. That's because each hour of operation of the retrofit plant generates revenue from CO_2 sales. With lower dispatch costs, the retrofit plant may operate more frequently, increasing electricity sales and increasing the economic value of the power plant asset. This dispatch advantage is illustrated in the example below, which shows the electricity price needed in the market to dispatch a power-generating unit. In this example, a Texas coal plant receives $34 per short ton of CO_2 sold to an EOR operator in the Permian Basin. It is depicted in the bar on the far left of the chart. The other units operate without CCS with the exception of the unit represented by the bar on the far right, which must pay to dispose of its captured CO_2 into a deep saline formation (not EOR). The illustration shows that EOR revenues could vault existing coal with CCS to the front of the dispatch order, and allow such units to recoup the significant up-front retrofit capital costs in the energy market.

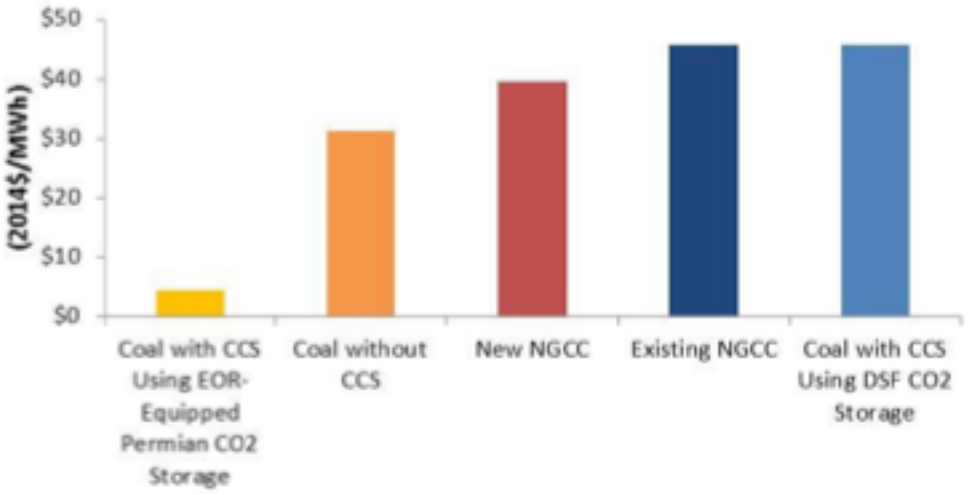


Figure 5: Illustrative dispatch cost advantage: Texas unit with CCS-EOR retrofit vs. other Texas Plants (Source: CATF).

Third, contrary to EPA's assertions, land requirements for CCS are not a major issue for all plants. A 2010 NETL study evaluated the feasibility of retrofitting capture technology at existing power plants, using aerial and satellite images of various power plant sites, and concluded that no sites were totally infeasible for retrofit.[169] And, for most plants, "there is the potential to have at least partial retrofit, which means retrofitting only some of the generating

[169] IEAGHG, *Retrofitting CO2 Capture to Existing Power Plants*, at 84, 86. (May 2011), *available at*: http://ieaghg.org/docs/General_Docs/Reports/2011-02.pdf.

units rather than the whole power plant."[170] Different capture technology options, especially oxyfuel, may require less space and increase partial CCS retrofit potential.[171]

Fourth, during the period between now and the 2030 target date it is not unrealistic to expect that pipelines can be built linking existing power plants to geologically favorable storage sites. So while it is certainly true that plants located closer to favorable geology are more likely to consider and install retrofit capture and sequester the captured CO_2, the need for pipeline construction is not a universal barrier to any retrofits between now and 2030. Indeed, the challenge presented by the need for more CO_2 pipelines to support the adoption of CCS retrofits is not conceptually very different from the challenge presented by the need to expand natural gas pipeline infrastructure to serve existing plants for repowering, or increase reliance on existing natural gas plants resulting from redispatch under building block 2.

Finally, adding CCS need not cut into the existing steam cycle of the power plant. As the plan for retrofitting the W. A. Parish plant in Texas demonstrates, the added power needed for CCS can be met by building a small gas plant adjacent to the existing facility. Indeed, this is not unlike the situation where small gas plants are needed for reliability purposes near some intermittent renewables.

For these reasons, CATF asserts that CCS retrofits are available over the period of this rule (to 2030) and should be included in building block 1 and used to evaluate state specific targets in the states identified as having EOR potential. Including some retrofit CCS not only better reflects projected reality under our modeling (described *infra*) but also has potential to yield significant contributions to state targets and overall national CO_2 reduction goals. The map below shows that the 17 states with EOR potential together account for about half of the total CO_2 reductions EPA projects will occur under the CPP from 2012 to 2030.

---

[170] Jia Li *et al*., *An assessment of the potential for retrofitting existing coal-fired power plants in China*, 4 ENERGY PROCEDIA 1805, 1811 (2011) (Ex. 4).

[171] IEAGHG, *Retrofitting CO2 Capture to Existing Power Plants*, at 84, 86. (May 2011) *available at*: http://ieaghg.org/docs/General_Docs/Reports/2011-02.pdf.

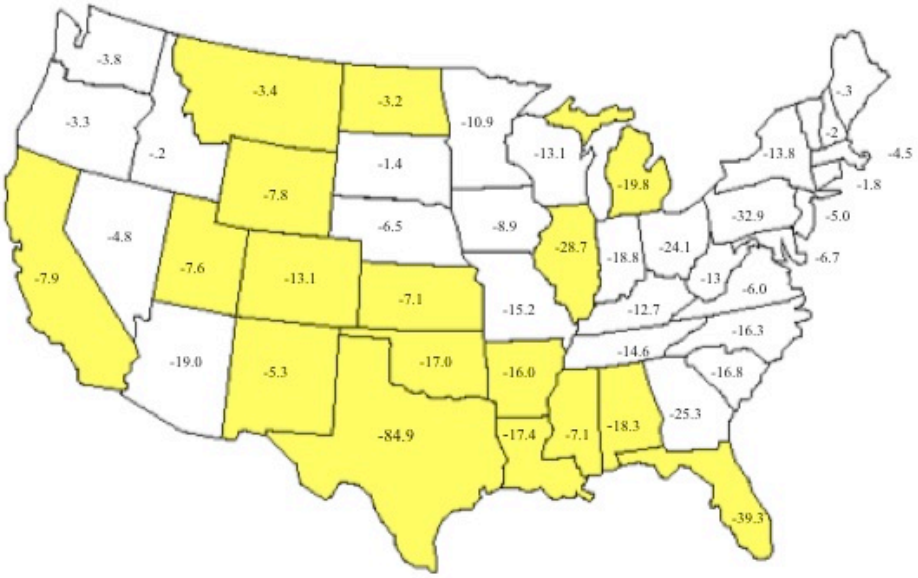


Figure 6: CO_2 Reductions by State from 2012 to 2030 Under the Clean Power Plan (Millions of Metric Tons). (Source: CATF).

And CCS can be grouped with other technologies that can reduce emissions directly at the designated facilities, under building block 1. Accepting for the sake of argument EPA's "broad applicability" criterion, as a whole this Unit Specific Measures approach to building block 1 would have broad applicability, just as building block 3 comprises a group of technologies not everywhere applicable[172] including nuclear generation.

Looking forward over the period 2014-2030, it is not unreasonable to assume that CO_2 pipelines could connect power plants in states without EOR potential to one of the states EPA currently identifies as having EOR sequestration potential. Providing a regulatory driver for CCS, by including some CCS retrofits in state target setting, would make an important contribution to the national CO_2 emission reduction goal.

The effect of including CCS retrofits in the state-specific target rates is illustrated by the example of Texas, which under the target rate developed by EPA is required to reduce its CO_2 emissions by nearly 85 million metric tons per year in 2030 relative to 2014 emissions. On a mass basis, Texas has the greatest emissions reduction target of any state in the proposed rule. However, Texas is also the state with the largest EOR operations in the U.S. In IPM model runs used to support the proposed rule, EPA has estimated that the annual quantity of CO_2 – EOR storage that is available to Texas power plants is 113 million short tons per year or 102 million metric tons.[173] So, CCS is "broadly applicable" to Texas because Texas sources have access to large EOR opportunities, and it has national significance because the state alone accounts for nearly 14 percent of the national CO_2 reductions that must occur between now and 2030 under the rule.

The choice of whether or not to retrofit a plant with CCS is an economic one. One factor in that choice, as EPA recognizes, is close proximity to EOR sites or pipelines. Other factors include the costs of capturing CO_2, transporting it by pipeline, and the revenue that a power plant owner receives for selling the CO_2 to the oil field. The "shadow price" of the CO_2 under the proposed regulation will also affect the choice whether or not to retrofit. We use the term "shadow price" to mean the marginal cost of abating the last metric ton of CO_2 in order to comply with the CPP's emission rate. In the CPP, different states have different emission targets and consequently, different shadow prices for CO_2. Generally, the deeper the emissions reductions in a state's target, the higher the shadow price of CO_2 in that state.

EPA's IPM modeling for the CPP predicted that no CCS would be built as a result of the rule. This was true even in states such as Texas where EOR is widely practiced, a retrofit project is already in construction, and the CO_2 shadow price under the rule would be expected to be large given the substantial CO_2 reductions represented by the state target. CCS is modeled in the CPP IPM runs using the assumptions found in EPA Base Case v5.13. This base case uses capture

[172] For example, off-shore wind is not "broadly applicable" – as EPA defines this concept – it is assuredly not capable of being developed everywhere in the nation, but only in coastal states. . However, by combining off-shore wind with other renewables, EPA creates the "renewables" portion building block 3.

[173] U.S. EPA, *EPA's Power Sector Modeling Platform*, at Table 6-2, (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

costs developed for new and retrofit plants, and combines them with storage and transportation costs developed with GeoCAT, a spreadsheet model developed by ICF to support EPA's Safe Drinking Water Act Underground Injection Control ("UIC") rulemaking in 2008.[174] GeoCAT develops commercial scale costs for storage in four of several possible settings: saline reservoirs, depleted gas fields, depleted oil fields, and EOR. These settings are characterized by "cost curves" that reflect total sequestration capacity and annual storage volumes in each region or state, at various costs.[175]

a. CATF commissioned modeling from Charles River Associates,[176] that corrected for outdated and incorrect EPA IPM assumptions.

CATF examined the CPP IPM runs and the assumptions that drove EPA's IPM results. We found significant problems that we observe lead to a dramatic understating of the amount of CCS projected to be built as a result of the CPP. A central problem is that GeoCAT has not been significantly updated since 2008. The GeoCAT "cost curves" for EOR price and supply thus are based on outdated assumptions, including:

- Oil prices are assumed to be $56 per barrel in GeoCAT. This low oil price significantly lowers the model's price paid for CO_2.
- CO_2 sent to EOR fields is assumed to meet Safe Drinking Water Act UIC program Class VI injection well standards, not UIC Class II with Clean Air Act subpart RR monitoring and reporting. As a result, EOR costs are overstated and the price field owners paid for CO_2 is understated in EPA's modeling.
- Since 2008, "next generation" EOR practices have been developed that greatly expand the EOR sequestration capacity in the United States. While GeoCAT assumes about 13 Gigatons of CO_2 EOR capacity, today's estimates are closer to twice that value.[177]
- Transportation costs included in GeoCAT are based on simplifying regional assumptions. But our observation is that at least for some states (Texas and Oklahoma, e.g.) these simplifications greatly overstate the costs of bringing CO_2 from power plants to EOR operations.

---

[174] U.S. EPA, *EPA's Power Sector Modeling Platform*, at ch. 6 (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

[175] *Id.* at 6-3.

[176] Charles River Associates is a leading global consulting firm that offers economic, financial, and strategic expertise to major law firms, corporations, accounting firms, and governments around the world. CRA's analytical and modeling tools are used to support expert testimony, assist clients in decision-making, provide input into valuation of assets, and provide insight into other complex matters in the electricity industry. CRA has developed proprietary analytic tools and models that have been used to: 1) value assets, 2) evaluate policy cost-effectiveness, 3) design market power-mitigation mechanisms, 4) evaluate contract portfolios, 5) optimize hydro dispatch, 6) test transmission constraints, 7) evaluate transmission investment economics and 8) evaluate market efficiency.

[177] *See CCS Assumptions Appendix A* for a detailed discussion of this capacity.

The maximum price paid for CO_2 in EOR operations anywhere in the U.S. under GeoCAT's assumptions is $14.52 per short ton. But CO_2 prices in the Permian Basin in 2014 were typically around $35 per short ton, by contrast, and elsewhere in the U.S.; prices paid for CO_2 to be used in EOR began at $20 per short ton.[178] Furthermore, the transportation costs assumed by GeoCAT likely overstate the pipeline costs by several dollars per short ton, at least in regions with existing EOR. Therefore the net revenue received for sale of CO_2 to the EOR operator by the power plant owner will be underestimated by EPA, because both the assumed value of the CO_2 in EOR is too low, and the assumed transportation costs are too high.

EPA's CO_2 capture scenarios – that is, the "world" modeled in the CPP IPM runs - also are limited. For example, CCS can only be retrofit on a coal unit; IPM does not allow CCS on any new or retrofit existing natural gas units. And coal unit retrofits are limited to a single size (400 MW or greater) and to 90 percent CO_2 capture only. Partial capture (for example, capture on only one unit of a multi-unit plant, leading to, say 50 percent capture was not an available option in the model. New build CCS also is limited just to 90 percent capture, and applied only on IGCC plants: IPM does not include even the partial capture option as EPA proposed it in the Agency's new source performance standards for this industry under Clean Air Act section 111(b). Taken together, these limited scenarios are likely to make CO_2 capture retrofits appear both much less likely, and much more expensive in the IPM model runs used to support CPP than if more expansive CO_2 capture scenarios are considered. A wider set of scenarios properly should include consideration of partial and full capture, on both new and existing natural gas and coal units (both pulverized coal and IGCC), and sensitivities concerning how unit size, coal types and existing plant heat rates impact capture costs.

i. CATF's modeling.

To address these issues, CATF developed its own model runs of the CPP rule. We replicated the CPP policy case, and then made changes only to the CCS assumptions used by EPA, in order to examine the impacts on CCS retrofits and new builds. CATF retained Charles River Associates ("CRA") to evaluate the economic competitiveness of CCS as a CPP compliance option for "CCS-Ready" states where CO_2 captured at power plants can be used for EOR.

CRA evaluated CCS as a compliance option in three target states: Texas, Oklahoma, and Mississippi. These three states were chosen due to the kinds of EOR activities currently underway there, which are representative of EOR activity taking place elsewhere in the country. Also, these states are in close physical proximity to one another making modeling simpler, and by focusing on three states, CATF could look more closely at transportation issues and EOR CO_2 price effects.

CRA configured the fundamental power market model North American Electricity and Environmental Model ("NEEM")[179] to reflect, to the extent possible, the modeling assumptions

[178] *See CCS Assumptions Appendix A* for a detailed discussion of these costs.

[179] NEEM is one of the leading models used to assess the impacts of energy and environmental policy on electricity markets.

used by the EPA in its CPP modeling. The resulting "EPA Policy Case" scenario provided a benchmark against which the results of subsequent assumption changes can be measured. In preparing the EPA Policy Case, CRA configured the NEEM model as follows:

- Aligned demand growth rates and energy efficiency deployment in NEEM regions to EPA's CPP assumptions.
- Updated planned additions and retirements in NEEM to be consistent with data from Energy Velocity, as EPA did.
- Adopted EPA's assumptions for coal CCS retrofits.
- Updated NEEM CCS transport costs based on IPM to State Mappings.
- Adopted EPA unit and retrofit characterizations, and build availability by technology type.
- Updated FOM and VOM for all existing units to be in line with EPA assumptions.
- Created emission regions specific to the study states from NEEM regions and imposed EPA emissions constraints.
- Adopted EPA's Henry Hub forecast and regional gas price bases.

Next, CRA configured a "CATF case" based on the "EPA Policy Case," and that altered only key assumptions describing CCS. CATF opted for CCS related changes that are reasonable, consistent with the general approach outlined by EPA in setting building blocks for BSER. CATF's "World 1: Updated Retrofit and EOR Assumptions" uses the same assumptions as the "EPA Policy Case" described above except that in World 1, the CCS assumptions are adjusted compared with the EPA Base Case, as described in Appendix A. Generally, the EOR prices are higher for the Permian Basin and the rest of the U.S. in World 1 than in the EPA Base Case, and higher EOR storage volumes, and lower CO_2 transportation costs in Texas, Oklahoma, and Mississippi also characterize World 1. World 1 includes the most realistic set of EOR assumptions along with other assumptions reflecting the EPA Policy Case, and therefore provides the best look at likely outcomes under the CPP.

CRA also ran four additional sensitivity cases, summarized in Table 1 below, representing alternative scenarios, by changing the assumptions about key drivers (e.g. fuel prices, CO_2 value, technology availability and costs) that will, or might, affect the cost of electricity and the value of captured CO_2.

- The "World 2: EPA Retrofit Costs with Updated EOR" case utilizes World 1 EOR and transport assumptions but maintains EPA's technology cost and availability.
- The "World 3: $80 Oil" is identical to World 1, except that the EOR value of CO_2 is derived from an $80 per barrel assumption, as opposed to a $100 per barrel assumption.
- The "World 4: Greenfield CCS Compliance" case is identical to World 1, except that greenfield CCS projects are allowed to count towards CPP compliance.
- The "World 5: High Gas Price" is identical to World 1, except that the natural gas price trajectory uses data from the AEO 2014 Low Oil & Gas Supply scenario.[180]

---

[180] U.S. EIA, *Annual Energy Outlook*, at E-9 (2014), *available at*: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

Table 1: Summary of modeling assumptions used by EPA and CATF (Source: CATF).

	EPA IPM Runs Base Case v5.13 (3)	CATF NEEM World 1	CATF NEEM World 2	CATF NEEM World 3	CATF NEEM World 4	CATF NEEM World 5
Maximum Price Paid for CO_2 with EOR ($/short ton) (1)						
Permian Basin	14.52	34.32	World 1	27.46	World 1	World 1
New Mexico	14.52	34.32	World 1	27.46	World 1	World 1
Texas Outside Permian Basin	6.67	13.33	World 1	16	World 1	World 1
Oklahoma	14.52	20	World 1	16	World 1	World 1
Mississippi	14.52	20	World 1	16	World 1	World 1
Rest of Nation	14.52	20	World 1	16	World 1	World 1
EOR Capacity (Million Short tons) (2)						
Permian Basin	5,633	3,104	World 1	World 1	World 1	World 1
New Mexico	672	672	World 1	World 1	World 1	World 1
Texas Outside Permian Basin	724	3,896	World 1	World 1	World 1	World 1
Oklahoma	1,168	2,545	World 1	World 1	World 1	World 1
Mississippi	135	317	World 1	World 1	World 1	World 1
Rest of Nation	5,214	5214	World 1	World 1	World 1	World 1
National Total	13,546	15,748	World 1	World 1	World 1	World 1
Transportation (2)						
Texas	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Oklahoma	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Mississippi	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Rest of Nation	GeoCat Table 6-3	GeoCat Table 6-3	World 1	World 1	World 1	World 1
CO_2 Capture (2)						
Coal Retrofits	1 case- greater than 400 MW, 90%	15 cases based upn heat rate,50% or 90% capture level, and unit size	EPA Base Case v5.13	World 1	World 1	World 1
Gas Retrofits	No	Yes-90%	EPA Base Case v5.14	World 1	World 1	World 1
Coal New Builds	1 case- IGCC 90%	8 cases based on coal type, PC and IGCC, 90% and 50% capture	EPA Base Case v5.15	World 1	World 1	World 1
Gas New Builds	No	Yes-90%	EPA Base Case v5.16	World 1	World 1	World 1
Greenfield CCS Plants Count as Compliance Option for CPP?	No	No	No	No	Yes	No
Gas Prices (2)	EPA Base Case v5.13	EPA Base Case v5.14	EPA Base Case v5.15	EPA Base Case v5.16	EPA Base Case v5.17	AEO 2012 low O & G supply

Notes

1. $14.52 per short ton is the maximum price GeoCAT pays for EOR anywhere in the nation EPA Base Case v5.13. This corresponds to STEP 1 in Table 6-2 for the GeoCAT model. Other EOR prices ($/short ton) include STEP 2 is 9.68; STEP 3 is 4.84, and STEP 4 is $0. See Appendix A for CATF STEP prices and storage.

2. See Appendix A for detailed discussion of CATF storage capacities, transportation coststs, CO_2 capture costs, and gas prices.

3. EPA Analysis of the Clean Power Plan at http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html and EPA's Power Sector Modeling Platform v.5.1 at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

ii. CATF's modeled EPA Policy Case and World 1 Results

The "EPA Policy Case" modeled by CRA successfully reproduced the results of the IPM policy case for 2030 developed by EPA to support the rule. It showed no CCS being built in response to the proposed rule, consistent with EPA's IPM modeling results.

Our World 1 scenario, including more realistic (higher) CO_2 purchase prices, greater storage volumes, and lower CO_2 transportation costs, by contrast predicted that nearly 95 million short tons/year of CO_2 (85 million metric tons) would be stored as a result of the CPP. These results appear in nine states including Texas, Oklahoma, New Mexico, Illinois, North Dakota, Kansas, Wyoming, Michigan, and Nebraska. Over half the modeled World 1 reductions come from storage in the Permian Basin in Texas. Figure 7 below summarize the projected storage by year and location, under World 1 assumptions.

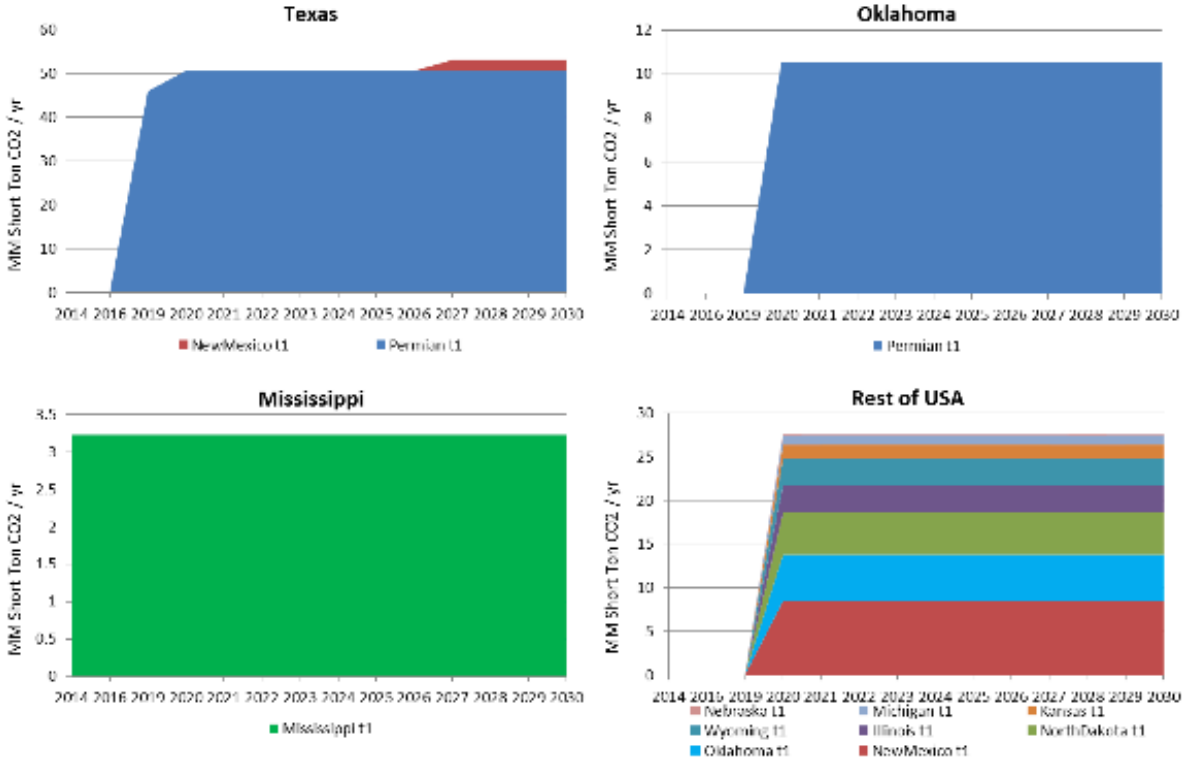


Figure 7: CO_2 sequestration in World 1 (summarizing the location of retrofits, new builds, and MW of capacity in World 1) (Source: CATF).

World 1: Updated Retrofit and EOR Assumptions				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,469	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,376	1	984

Table 2: (Source: CATF).

As Table 2 shows, 19 units nationwide and two new build CCS units occur in World 1. This represents over 10 GW of retrofits on existing coal units, well above the zero retrofits predicted by the EPA Policy Case.

iii. CATF sensitivities (Worlds 2 – 5) and results.

Figure 8 shows the amounts of CO_2 storage projected to occur under each of the other modeled CATF sensitivities – that is, Worlds 2 through 5 – graphed together with the EPA base case and World 1. As the figure shows, World 5 (high gas prices) drives the highest levels of CCS. Worlds 4 and 1 produce the next highest levels of CCS (about 95 million short tons stored). And, Figure 8 below summarizes the CCS retrofits and new builds predicted across all regions, under the EPA Policy Case and the CATF scenarios (Worlds 1-5).

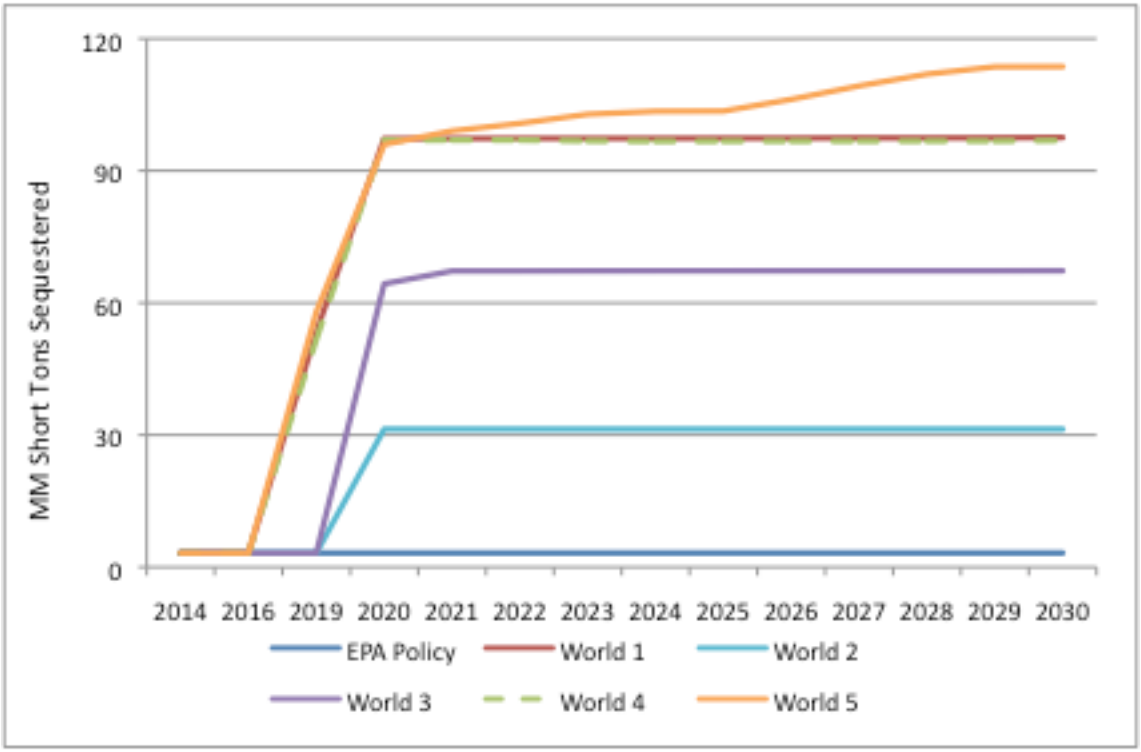


Figure 8: CO_2 storage under CATF's modeled scenarios (Source: CATF).

Table 3 below summarizes the CCS retrofits and new builds across all modeled scenarios. With the exception of World 5, all of these units are coal-fired with 90 percent capture. Under the World 5 scenario, some of the greenfield units utilize partial (50 percent) capture.

Table 3: CCS Units and Capacity in Modeled Scenarios 2014 – 2030 (Source: CATF).

Texas	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	10	6,469	0	0
CATF World 2	6	3,370	0	0
CATF World 3	8	4,791	0	0
CATF World 4	10	6,472	0	0
CATF World 5	11	7,273	1	759

Oklahoma	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	3	1,241	0	0
CATF World 2	1	490	0	0
CATF World 3	2	571	0	0
CATF World 4	3	1,241	0	0
CATF World 5	3	1,526	0	0

Mississippi	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	1	840
CATF World 1	0	0	1	840
CATF World 2	0	0	1	840
CATF World 3	0	0	1	840
CATF World 4	0	0	1	840
CATF World 5	1	440	2	1,201

Rest of USA	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	6	2,376	1	984
CATF World 2	1	120	0	0
CATF World 3	4	1,795	1	1,084
CATF World 4	6	2,363	3	1,445
CATF World 5	7	4,605	2	2,678

World 1: Updated Retrofit and EOR Assumptions				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,469	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,376	1	984

World 2: EPA Retrofit Cost with Updated EOR				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	6	3,370	0	0
Oklahoma	1	490	0	0
Mississippi	0	0	1	840
Rest of USA	1	120	0	0

World 3: $80 Oil				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	8	4,791	0	0
Oklahoma	2	571	0	0
Mississippi	0	0	1	840
Rest of USA	4	1,795	1	1,084

World 4: Greenfield CCS Compliance				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,472	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,363	3	1,445

World 5: High Gas Price				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	11	7,273	1	759
Oklahoma	3	1,526	0	0
Mississippi	1	440	2	1,201
Rest of USA	7	4,605	2	2,678

Projected CO_2 reductions under the modeled scenarios are significant. Figure 8 and Table 3 support a variety of findings:

- Table 3 shows that under our World 2 scenario, CATF's modeling projects 3370 MW of CCS-EOR retrofits in Texas, 490 MW of CCS-EOR retrofits in Oklahoma and 120 MW of CCS-EOR retrofits in the rest of the country, or about 4 GW of CCS-EOR retrofits total. World 2 adopts EPA's CO_2 capture cost assumptions but more realistic EOR prices, transport costs and storage capacity in key EOR states. This increase in CCS retrofits is significant, as compared with the EPA Policy Case.

- Higher natural gas prices under CATF's World 5 scenario drive significant increases in CCS retrofits and in the corresponding quantities of CO_2 stored/reduced from atmospheric release. Increasing the long-term natural gas price by approximately $2/MMbtu in the model, created incentives for greenfield 50 percent capture units in Mississippi and Texas not seen in other scenarios. Our World 5 predicts nearly 14 GW of retrofit capacity nationwide. This underscores the importance of CCS on coal as a hedge against higher natural gas prices.

- World 3 ($80 oil with CATF retrofit costs) predicts more CO_2 storage than World 2 ($100 oil and EPA retrofit costs). Both scenarios predict less CO_2 will be stored than is predicted under the World 1 scenario. These comparisons show that CATF's updated CCS retrofit cost/penalty assumptions are more influential than the $80 vs. $100 oil prices, in driving CCS and lowering marginal CPP compliance costs.

- In all scenarios modeled, CCS retrofits are preferred to CCS-equipped new builds even in a case where new CCS-equipped plants can count towards CPP compliance.

The three states examined in detail in CATF's modeling also showed differing levels of CCS penetration in the predicted 2016, 2020, 2025 and 2030 generation mix. These results are summarized in Figure 9. Figure 9 shows the percentage of TWH from each category of generation and equivalent demand side energy efficiency in 2016, 2020, 2025 and 2030. Both Texas and Oklahoma show significant CCS penetration. In 2030, CCS on coal units represents 4 - 9 percent of the generation mix in Texas depending upon the scenario, and about 4 percent of the generating mix in Oklahoma. In Mississippi, the only CCS plant is Kemper, which is under construction and expected to begin CCS operations in 2015. In our modeling, Kemper absorbs most of the EOR-enabled CO_2 storage in Mississippi, curtailing incremental CCS.

In both Texas and Oklahoma, modeled increased coal CCS retrofits come at the expense of new NGCC plants. CCS retrofitted on existing coal plants prevents some retirements of coal units and postpones when new NGCC plants are built. In Texas, the new NGCC falls from about 171 TWH in the EPA Policy Case in 2030, to 124 TWH to 152 TWH in the CATF World 1 through 5 scenarios. In Oklahoma, New NGCC in the EPA Policy Case is predicted to reach 28.5 TWH in 2030. CATF's modeling predicts CCS at Oklahoma coal plants but reduces the amount of new NGCC electricity production to a range of 14.5 -24 TWH depending upon the scenario. The amount of hydroelectric, nuclear, non-wind renewables, wind and demand side energy efficiency are unchanged compared to the EPA Policy Case.

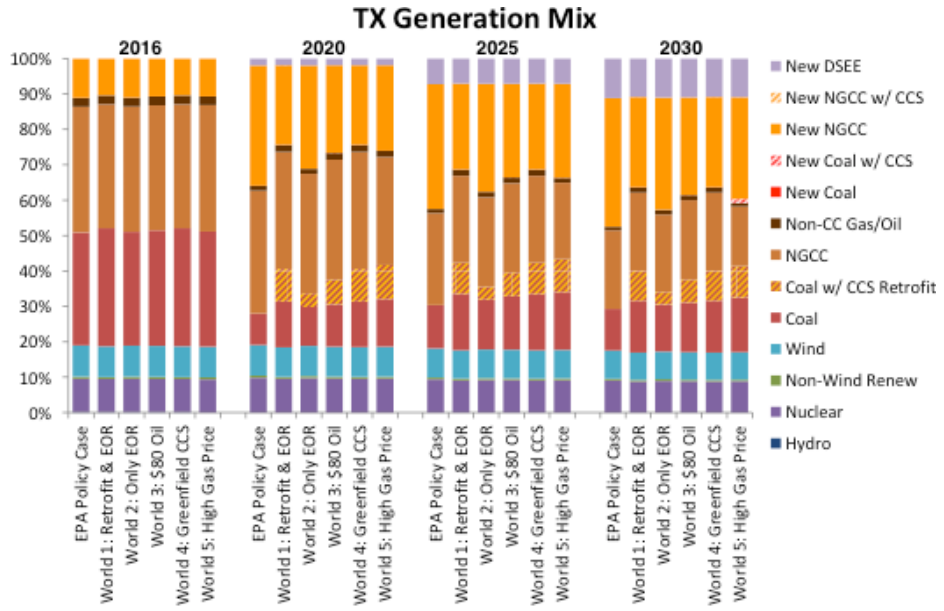
The CATF modeling also predicts that CCS retrofits in Texas, Oklahoma and Mississippi can allow more non-CCS coal to operate. This is because CCS retrofits can allow "border line"

non-CCS coal units to remain online and/or generate more without violating CPP rate limits. But as Table 4 below shows, these increases above the EPA Policy Case, where they exist, are modest.

Percentage Change in CO_2 Emissions in World 1 from the EPA Policy Case

	2020	2030
Texas	1.7%	2.1%
Oklahoma	0.2%	-2.0%
Mississippi	1.6%	1.8%

Table 4: (Source: CATF).



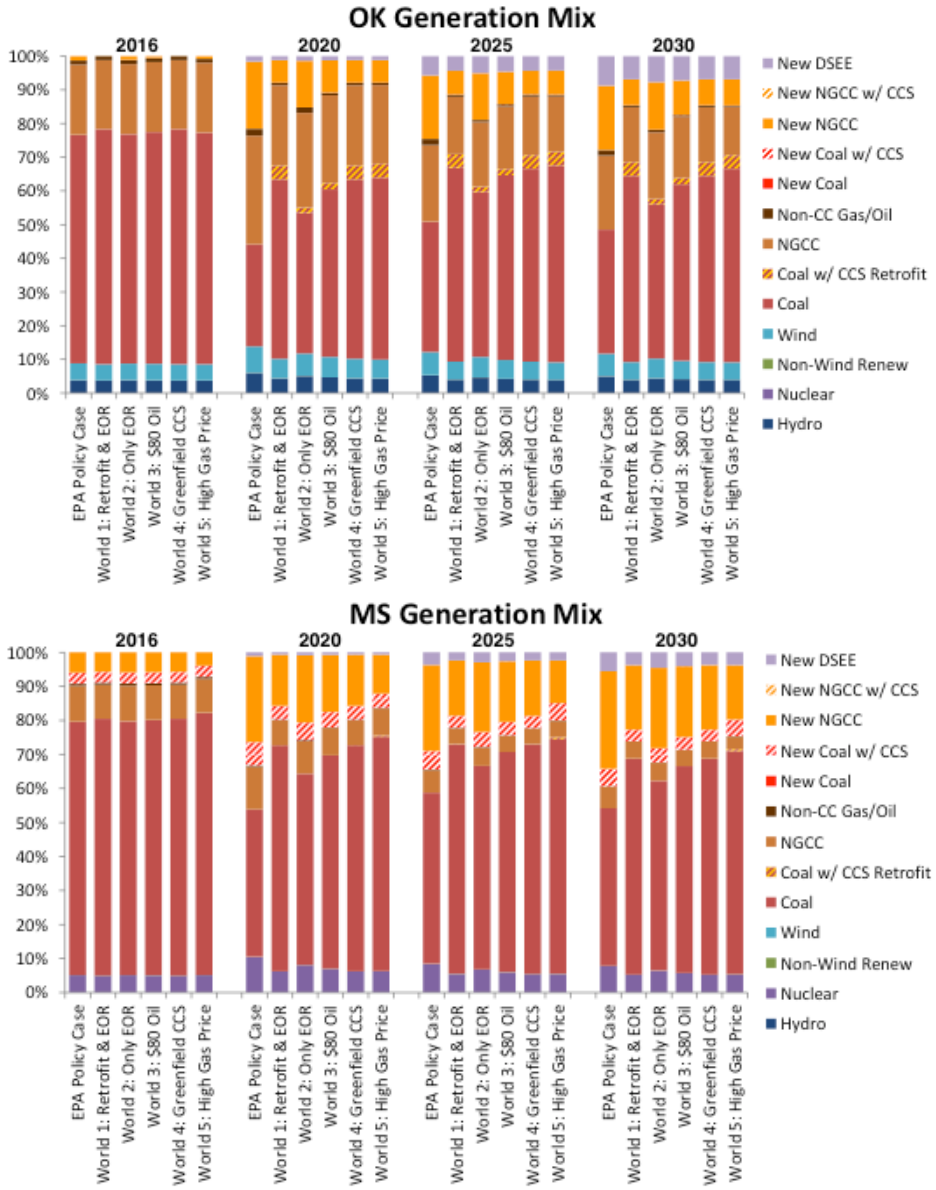


Figure 9: Generation mix in Texas, Oklahoma and Mississippi: 2016, 2020, 2025 & 2030, under modeled scenarios (Source: CATF).

With respect to costs of CCS retrofits, our modeling showed small but meaningful decreases in total system costs in the areas we studied. The shadow price for CO_2 (again, the marginal cost of abating the last metric ton of CO_2 in order to comply with the rule) varied in the modeled EPA Policy Case, depending upon year. For Texas, the shadow price in 2020 was $30 per short ton and dropped through 2029 to around $15 per short ton. For World 1, the shadow price of CO_2 was generally about $10 per short ton less than the EPA Policy Case, across all years. Other modeled scenarios showed lower shadow prices than the EPA Policy Case with the exception of the World 5 scenario, the high natural gas price scenario. In World 5, higher natural gas prices drive abatement costs up, although CCS retrofits on coal units do help mitigate to some degree these higher gas price effects.

CATF's model runs also show that there are small but meaningful decreases in total system costs in the regional transmission organization ("RTOs") encompassing Texas and Oklahoma, where CCS is retrofit. More favorable CCS economics allow more existing coal to survive and in turn forestall new NGCC builds. The total system costs reductions are depicted in Figure 10 below.

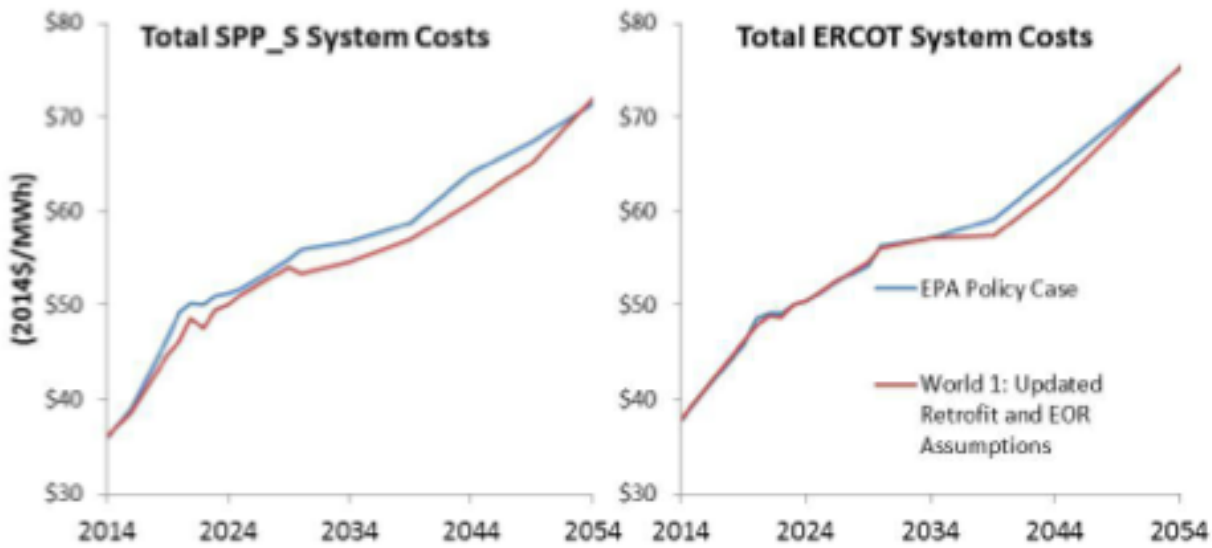


Figure 10: System costs in the Oklahoma and Texas RTOs: World 1 vs. EPA Policy Case (Source: CATF).

Figure 10 shows, in present value (2014-2054) terms, that the total system costs in the Oklahoma RTO ("SPP_S") decrease by $5.1 billion under CATF World 1 assumptions, or by 2.4 percent as compared with the EPA Policy Case. Similar results are observed in the Texas RTO ("ERCOT"). In ERCOT, total system costs decrease by $2.4 billion, or 0.5 percent as compared with the EPA Policy Case. This demonstrates that World 1 can achieve lower electricity prices in the modeled regions than will the EPA Policy Case.

2. Conclusions and recommendations.

a. CCS is a significant compliance pathway in two of the three EOR states studied in detail by CATF.

As Table 5 below shows, CATF's modeling predicts significant CO_2 tonnage reductions will be achieved using CCS-EOR retrofits on affected units in Texas, and this accounts for 25 - 65 percent of the total CO_2 reductions that must be achieved in 2030 as a result of the CPP Texas CO_2 emission targets. For Oklahoma, CATF's modeling predicts CO_2 reductions using CCS-EOR retrofits of between 21and 92 percent of the 2030 CPP targets, depending on the scenario modeled. In Mississippi, the only CCS shown in the CATF modeling is Kemper, which is considered an existing source under the rule.

Table 5: Texas and Oklahoma modeled CO_2 storage as a percentage of the 2030 CPP state goals.

	Texas	
	MM Metric Tons Stored Through EOR in 2030	**% of 2030 Texas Target (84.87 MM Metric Tons)**
World 1	48.20	57%
World 2	20.82	25%
World 3	36.22	43%
World 4	48.21	57%
World 5	55.42	65%
	Oklahoma	
	MM Metric Tons Stored Through EORin 2030	**% of 2030 Oklahoma Target (16.98 MM Metric Tons)**
World 1	14.37	85%
World 2	3.54	21%
World 3	9.40	55%
World 4	15.99	94%
World 5	15.55	92%

The emissions reductions that our modeling shows can be achieved by CCS-EOR retrofits are significant when compared with the sum of the CPP's state emissions reductions targets. In the continental United States, the CPP is expected to reduce emissions from existing affected sources by over 607 million metric tons per year in 2030 relative to 2012 levels.[181] As shown in Table 6 below, our modeling predicts that CCS-EOR retrofits can account for between 4 and 16 percent (depending on the scenario modeled) of the U.S. total CO_2 reductions under the CPP.

[181] U.S. EPA, *Technical Support Document: Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents*, Docket ID No. EPA-HQ-OAR-2013-0602 (Nov. 2014) [hereinafter *Rate-Based to Mass-Based Translation TSD*].

Table 6: CO_2 Storage in U.S. modeled scenarios (Source: CATF).

	World 1	World 2	World 3	World 4	World 5
Million Metric Tons Stored by CCS-EOR in 2030	85.57	25.50	58.12	84.94	100.17
% of Continental US 2030 reduction target compared to 2012 emissions achieved by CCS-EOR	14%	4%	10%	14%	16%

Another way to evaluate the significance of the CCS-EOR reductions modeled by CATF is to compare them to the reductions EPA estimated in assessing the CO_2 reduction potentials of its various building blocks. For example, EPA developed a simplified cost estimate for its building block 1 (HRI), which it modeled would achieve 97 million metric tons of CO_2 reductions by 2030[182] By comparison, the total CO_2 reductions modeled to be achieved by 2030 using CCS-EOR in the scenarios modeled by CATF range between 25 and 100 million metric tons. The World 1 scenario incorporates what CATF believes are the best estimates for both EOR price, supply and CO_2 transportation and best estimates of retrofit costs. Therefore the most likely result is 85 million metric tons sequestered under the World 1 scenario – an amount comparable with the CO_2 reductions EPA projects will be achieved by heat rate improvements.[183]

The modeled CCS-EOR CO_2 emissions reductions moreover are economically reasonable. As described earlier in the analysis and results section, the reductions in World 1 are achieved at less cost than in the EPA Base Case. The CATF World I run showed that there are small but meaningful decreases in total system costs in the RTOs encompassing Texas and Oklahoma, where CCS is retrofit. In present value (2014-2054) terms, total system costs in

[182] *GHG Abatement Measures TSD*, at 2-39.

[183] EPA's IPM model predicts 10 GW of incremental non-hydroelectric renewable generating capacity to be in place between 2020 and 2030 under the CPP. *See* U.S. EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, at 3-34, Table 3-12, Docket No. ID: EPA-HQ-OAR-2013-0602-0391 (June 2014) [hereinafter *RIA*] (showing predicted non-hydro renewables in 2030 in the "Option 1 State" at 115 GW, and in 2020 at 105 GW, a difference of 10 GW). Over the same period, CATF's modeling shows 10 GW of retrofitted CCS capacity resulting from our modeled World 1 scenario.

SPP_S decrease by $5.1 billion, or 2.4 percent, and in the ERCOT, system costs decrease by $2.4 billion, or 0.5 percent.

3. EPA should adjust relevant state-specific building blocks to include CCS-EOR, especially if the Agency opts to finalize a rule based solely on building blocks 1 and 2.

In summary, the result of adding CCS-EOR retrofits to the BSER building block 1 would be a target rate that reflects an incremental amount of CO_2 reductions on the order of 85 million metric tons per year in 2030. This is a significant quantity of CO_2. In comparison, building blocks 3 and 4 together reduce CO_2 by 262 million metric tons per year relative to the 2020 base case.[184] The contribution by CCS could therefore be about 32 percent of the total contribution of building blocks 3 and together.

If EPA finalizes its block 1 and 2 only approach to target setting, including CCS as part of building block 1 (referred to as Unit Specific Measures in these comments) helps maintain the stringency of the rule at a reasonable cost.

b. Building block 2 is reasonable if not conservative.

EPA has requested comment on all aspects of its findings related to building block 2, which assesses the potential for CO_2 reductions based on the displacement of existing high-emitting coal generation with natural gas, through a redispatch mechanism to be directed by states and RTOs.[185] EPA assumes a 64 percent average existing natural gas unit utilization factor as well as imposing a "ceiling" of 70 percent, and specifically requests comment on whether it should consider a higher utilization rate (up to 75 percent).[186] CATF's Power Switch report[187] and underlying economic analysis commissioned by CATF from The NorthBridge Group ("NorthBridge")[188] supports the conclusion that EPA's proposed emission rate targets are

---

[184] The total amount of CO_2 reductions from building blocks 3 and 4 is 262 MM tonnes in 2030 relative to the 2020 base case. This is calculated from the total amount of reductions in the rule of 555 MM tonnes (*RIA* at Table ES-2) minus the amount of reductions from building blocks 1 and 2, which is 293 MM tonnes (U.S. EPA, *Memo: Emissions Reductions, Costs, Benefits and Economic Impacts Associated with Building Blocks 1 and 2*, at 3 (June 2014)).

[185] 79 Fed. Reg. at 34,862-34,866.

[186] *Id.* at 34,865.

[187] CATF, "*Power Switch*: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants" (Feb. 2014), *available at:* http://www.catf.us/resources/publications/files/Power_Switch.pdf.

[188] The NorthBridge Group is an economic and strategic consulting firm serving the electric and natural gas industries, including both regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge's practice is national in scope, and they have long-standing consulting relationships with a number of electric utility clients across the country. NorthBridge applies market insights, rigorous quantitative skills and regulatory expertise to solving complex business and policy challenges.

reasonable and, specifically, that EPA's proposed building block 2 is reasonable, if not conservative: EPA's proposed 70 percent utilization "ceiling" for natural gas utilization could be raised to at least 75 percent.

i. CATF's Power Switch used state-of-the-art modeling and realistic assumptions to show the CO_2 reductions achievable using a common sense gas-redispatch scenario.

During the stakeholder process leading up to EPA's proposal, CATF suggested a common sense approach to existing fossil fueled power plant CO_2 emissions reductions based on performance standards designed to result in displacement of power generation from the highest-emitting coal-fired power plants by generation from under-utilized, efficient natural gas plants. Building block 2 of the CPP proposal reflects this concept of natural gas for coal "redispatch."

In *Power Switch*, CATF suggested that if EPA set separate emission rate target standards for fossil-fueled utility boilers at 1,450 lbs. CO_2/MWh, and for natural gas combustion turbines at 1,100 lbs. CO_2/MWh,[189] and facilitated least-cost implementation for states by issuing a model interstate trading rule with the opportunity to use the free allocation of allowances to protect electric retail ratepayers of all classes, significant CO_2 reductions would be achieved through coal to gas redispatch. The NorthBridge analysis used two main models. The first, *FastForward*,[190] is a commercially available fundamental dispatch and wholesale market price forecasting tool developed by NorthBridge for EPRI. For the purpose of this effort, *FastForward* was run on a deterministic basis to produce hourly pricing results for the power grid reliability regions here:

[189] 1,100 lbs CO_2/MWh is a rate consistent with the performance of the vast majority of existing natural gas-fired affected units today. Edward Rubin, Carnegie Mellon University *A Performance Standards Approach to Reducing COEmissions from Electric Power Plants*, at 8 (June 2009) *available at*: http://www.c2es.org/docUploads/Coal-Initiative-Series-Rubin.pdf. *See also* 79 Fed. Reg. 1,447.

[190] *FastForward* is a PC-based VisualBasic model designed to rapidly generate forward market prices for electricity on a probabilistic basis. At its core, it is a multi-region dispatch model that quickly estimates hourly electric market-clearing prices under an array of load, resource and commodity scenarios. The model relies on a Scenario Generation module to identify statistically meaningful scenarios based on volatility and correlation parameters for each input variable. The market price outputs derived for each scenario describe a sample distribution from which a variety of statistics are calculated. In addition to the expected market price trajectory, the Statistical Estimation module can calculate the probability distribution associated with market prices and correlations with other variables. *FastForward* is used by major investor-owned utilities, competitive generating companies, load-serving entities and consulting firms in the United States to forecast market prices, assess generating asset market values and develop risk management plans.

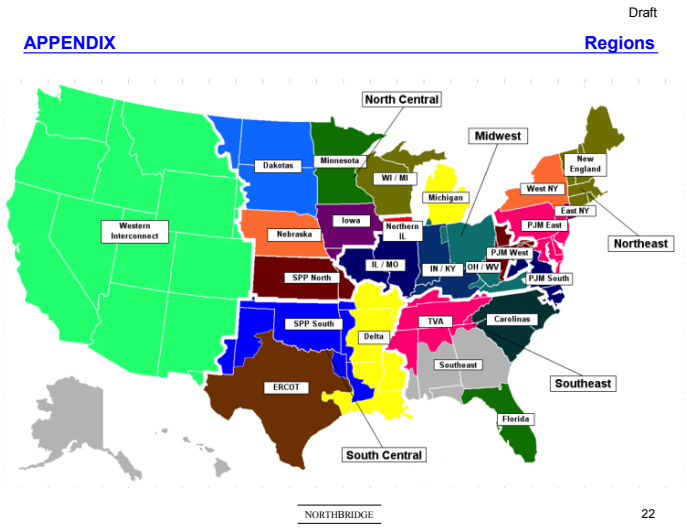


Figure 11: Power grid reliability regions used in FastForward (Source: NorthBridge).

The second part of the NorthBridge analysis used a proprietary emissions compliance-planning model,[191] which takes as its inputs the unit-specific generating data and regional hourly market price results from FastForward, along with NorthBridge-developed cost and performance assumptions for carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury emission control technologies from. It then estimates unit retirement and emission control retrofit decisions annually. And sensitivities also can be run achieving results under alternate commodity assumptions and regulatory scenarios.

The compliance model is easily adapted to evaluate the impact of potential new conventional pollutant policies, with or without carbon pricing policies. The NorthBridge model also uses unit retirement decision assumptions that are based on economic criteria tailored to the regulated and merchant ownership status of individual units rather than engineering or physical unit criteria (such as age, etc.), in order to more accurately reflect the manner in which unit owners make unit retirement decisions.

[191] The advantages of using the NorthBridge modeling platform and mode of analysis over other dispatch models include that: (1) it provides unit-specific results (unlike ICF Consulting's Integrated Planning Model/IPM model which analyzes only "model" units and then "parses" the run results to specific real-world units;) (2) investor owned utility companies, competitor generators, load-serving entities, and other consulting firms all rely on the NorthBridge model and analysis in making business decisions including asset valuation for the purchase or sale of units, regulatory compliance decisions and planning, etc.; and (3) it allows the analysis of the "phase-in" of policies over time (unlike the IPM model) which avoid electricity and gas price spikes that are artifacts of the model and not representative of real world conditions.

ii. The gas prices and gas price response assumptions in EPA's IPM modeling analysis are too high, needlessly constraining the potential cost-effective role of additional use of natural gas in the redispatch of existing and new NGCC units as well as through gas co-firing in coal units.

Several proposed findings in the CPP are sensitive to EPA's assumptions regarding gas price and gas price response (i.e., gas price elasticity) including: the 70 percent "ceiling" for existing gas unit utilization in building block 2 and the decision not to include new NGCCs or gas co-firing in the BSER determination and state goal calculation methodology.

The gas price forecast in the June 2014 IPM base case (adjusted to nominal dollars using a 1.5 percent annual inflation rate) starts at $5.70/MMBtu in 2020 and rises to $7.00/MMBtu by 2025.[192] In contrast, recent NYMEX prices (in nominal dollars) start at just $4.43/MMBtu and only rise to $4.84/MMBtu during the same period.[193] This means the June 2014 base case IPM prices are roughly $1.25/MMBtu to $2.00/MMBtu higher than current NYMEX prices. This is equivalent to a 30 percent to 45 percent premium. *See* Figure 12 below. Note that since current NYMEX prices are well within the range of NYMEX prices over the last year, this conclusion is not the result of a temporary or unusual pattern of NYMEX prices, but a more basic shift.

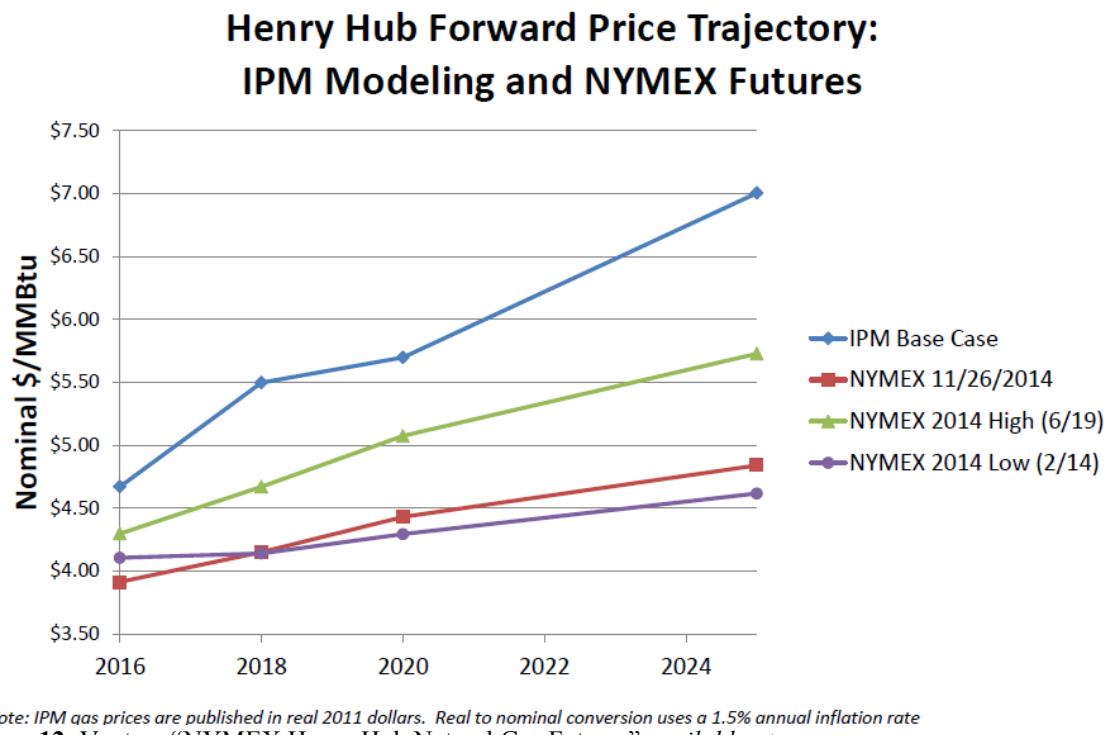


Figure 12: Ventyx, "NYMEX Henry Hub Natural Gas Futures" *available at*: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite.

[192] Ventyx, "NYMEX Henry Hub Natural Gas Futures" *available at*: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite

[193] *Id.*

The fact that the June 2014 base case IPM gas price assumptions are 30 to 45 percent higher than current market expectations suggests the gas resource assumptions (that is, the cost of production and quantity of gas resources) underlying the IPM estimates are overly conservative compared to current market expectations. The market forwards suggest that there may well be a larger quantity of gas reserves and lower cost of production than is reflected in the June 2014 IPM base case.

Since the base case prices appear high, the increase in gas prices forecasted in the policy cases may well also be overstated. If there is more natural gas available at relatively low prices, then increased demand for natural gas may cause prices to rise by a smaller amount than forecasted in the IPM policy cases. This overstatement of gas prices raises the estimated cost of the CPP rule and can cause the role of gas in the compliance mix to be understated.

iii. EPA should update the gas price and gas price response assumptions that it uses in its IPM compliance modeling.

The gas price response (i.e., gas price elasticity assumptions) built into EPA's IPM model appear to be materially higher than those reflected in the NorthBridge analysis of the CATF Power Switch approach and the recent Rhodium Group analysis of the CPP using the NEMS modeling platform.[194]

Figure 13 below shows the percent change in U.S. electricity consumption predicted by EPA's IPM modeling in the RIA, Rhodium Group's analysis for CSIS (using the NEMS model), and the NorthBridge analysis of CATF's Power Switch proposal (using FastForward and the proprietary NorthBridge unit dispatch model).

[194] The Rhodium Group for the Center for Strategic and International Studies, *Remaking American Power*, (July 24, 2014) (updated Oct. 2, 2014) *available at*: http://csis.org/files/attachments/140724_RemakingAmericanPower.pdf; Clean Air Task Force, *Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants*, (Feb. 2014), *available at*: http://www.catf.us/resources/publications/files/Power_Switch.pdf; *See also* The NorthBridge Group, *Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions*, (Feb. 2014) *available at*: http://www.catf.us/resources/publications/files/NorthBridge_111d_Options.pdf.

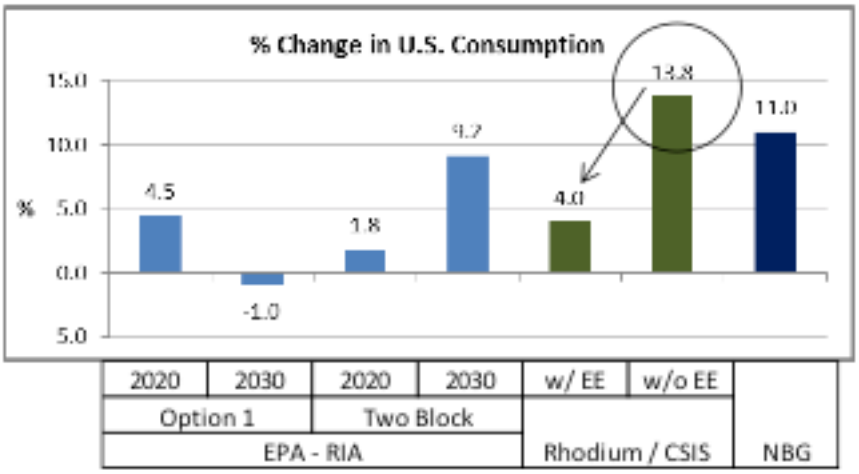


Figure 13: (Source: NorthBridge).

Figure 14 below shows the percent change in electricity price per percent change in U.S. consumption. Comparing the results demonstrates that the gas price response in EPA's IPM modeling is more sensitive to gas demand than either NEMS or the NorthBridge modeling platform by at least factor of 2 to 6.

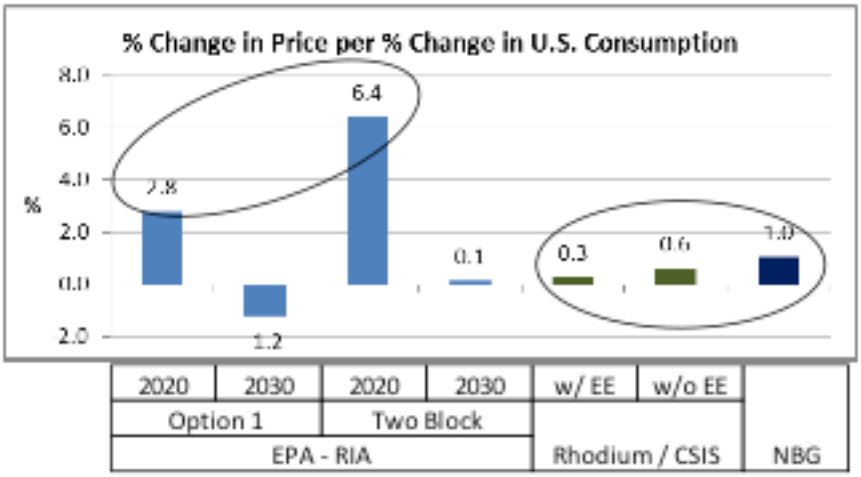


Figure 14: (Source: NorthBridge).

This indicates that the gas price elasticities in EPA's IPM modeling may reflect an overly sensitive gas price response that does not fully account for the potentially large quantity of shale gas reserves. As a result, EPA's modeling could overstate the natural gas price impact of the CPP policy and needlessly constrain the potentially cost-effective role of additional use of natural gas in redispatch of existing and new NGCC units as well as through gas co-firing in coal units.

iv. Power Switch modeling results show that EPA's proposed 70 percent utilization factor for natural gas fired units is reasonable.

We compared the Power Switch results to the EPA CPP modeling, and found that the

amount of coal generation (and, therefore CO_2 emissions) displaced by higher utilization of natural gas in the policy modeled in Power Switch is close to the redispatch effect modeled by EPA in building block 2.[195] Because the Power Switch approach and EPA's building block 2 include comparable assumptions, the NorthBridge economic analysis demonstrating the feasibility of the Power Switch approach also lends support for the reasonableness of EPA's proposed building block 2, and therefore to EPA's proposed target emission rates in general.

The result of implementing the Power Switch approach, NorthBridge found, would be that operators would shift reliance from the highest- emitting coal units to existing under-utilized natural gas units, thereby reducing CO_2 emissions by about 27 percent, as compared with 2005 levels, or by 636 million metric tons.[196] The analysis demonstrated that these results could be achieved at a marginal cost of only $34/metric ton CO_2 ($2013) while ensuring electric and gas system reliability. Both the marginal cost and the average cost of the Power Switch concept ($32/metric ton CO_2 ($2013)), are less than the Social Cost of Carbon ("SCC") put forward by the U.S. government.[197]

By definition, the NorthBridge economic modeling analysis selects the least-cost compliance pathway to achieve emissions performance. NorthBridge's analysis of the Power Switch approach found that by 2020, almost 70 percent of the compliance would be achieved through redispatch of natural gas generation to replace coal generation.[198] The remainder of the CO_2 reductions would result from a combination of heat rate improvements, some coal unit retirements, and a small amount of demand reduction due to electric price response. The result: a remarkable decrease in CO_2 emissions from the power sector simply by optimizing the existing fossil electric system to use the most efficient power plants first.

---

[195] *Compare* EPA IPM result found at *RIA* Table ES-2 (371 MMT CO_2 reduction from base case in 2020) *with* Power Switch at 6 (308 MMT CO2 reduction from base case in 2020).

[196] The Power Switch approach also predicted additional public health benefits including 2,000 avoided premature deaths and 15,000 avoided asthma attacks annually as a result of the annual reductions of over 400,000 tons in sulfur dioxide (SO2) emissions and nitrogen oxides (NOx) emissions in 2020 associated with the reduced utilization of covered coal plants. Those health benefits represent $34 billion in benefits, or over three times the cost of compliance. And the Power Switch approach was predicted to increase average nationwide retail electric rates by only 2 percent in 2020 which, based on Energy Information Administration forecasts, should result in no net increase in monthly electric bills.

[197] *See* U.S. EPA, "The Social Cost of Carbon" http://www.epa.gov/climatechange/EPAactivities/economics/scc.html; *and* Interagency Working Group on Social Cost of Carbon, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*, (May 2013) *available at*: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

[198] *Power Switch* at 7, 22 Fig.12.

Summary of Results by 2020	
Reduction in fossil CO2 (%) from 2005 levels	-27%
Reduction in CO2 (metric tons) from 2005 levels	636
Reduction in CO2 (metric tons) from forecast 2020 levels	308
CO2 price ($ 2013/metric ton)	$20
Reduction in coal TWh (%)	-27%
Coal retirements (GW)	42
Increase in gas consumption (TCF)	3.0
Increase in Henry Hub gas price ($/MMBtu)	11.4%
Increase in US wholesale electric price (%)	6.9%
Increase in US retail electric price – without allowance offset (%)	6.2%
Increase in US retail electric price – with allowance offset (%)	2.3%
Marginal cost ($ 2013/metric ton)	34
Average cost ($ 2013/metric ton)	32
Total program costs ($ 2013 billion)	9.4
Total program benefits ($ 2013 billion)	34

Table 7: (Source Northbridge).

The following chart illustrates the amount of coal-to-gas redispatch predicted nationwide by the NorthBridge analysis of the Power Switch approach in 2020, relative to a 2020 "business-as-usual" base case.

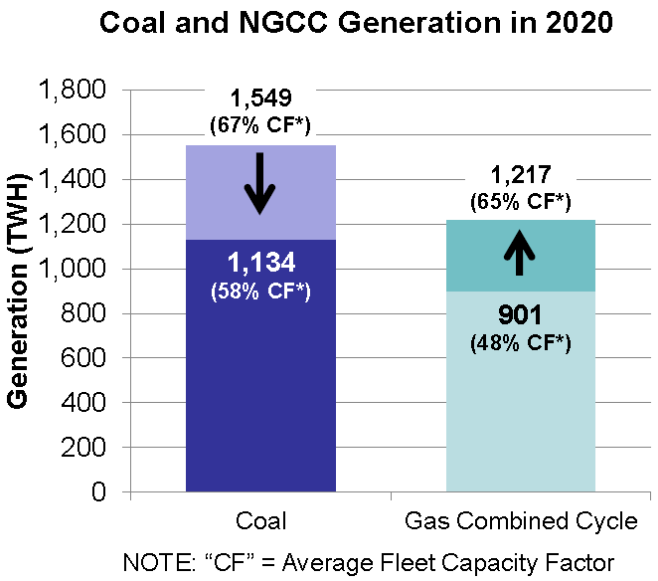


Figure 15: (Source: NorthBridge).

Figure 15 shows the average national utilization factor (or capacity factor or ("CF")) for coal units would fall from 67 percent to 58 percent. The utilization factor for natural gas combined cycle units would increase from 48 percent to 65 percent. This increase in gas unit utilization factor is almost identical to the 64 percent national average natural gas utilization factor EPA derived in building block 2 in the CPP proposal.[199] Additionally, the NorthBridge modeling predicts that in several states, natural gas combined cycle units would exceed the 70 percent utilization factor level, some by a substantial amount (up to 85 percent). Thus, the NorthBridge analysis provides evidence that EPA's proposed 70 percent utilization ceiling is reasonable, if not conservative, and provides support for EPA raising the natural gas unit utilization ceiling to at least 75 percent.

The Power Switch approach would protect system reliability and grid stability by relying on proven, existing fossil electric units that are in operation today. Moreover, the Power Switch modeling results, which find that through an interstate trading system commensurate carbon dioxide reductions can be achieved affordably and reliably show that concerns about the cost impacts and system reliability associated with higher levels of gas redispatch and unit utilization than EPA has proposed in the CPP can be mitigated by EPA facilitating an interstate trading program by the states. A streamlined, easily implemented interstate trading program (perhaps through multistate or "linked state plans") would mitigate cost impacts under any approach to

[199] The EPA's Goal Data Computation spreadsheet shows that the average capacity factor for the existing U.S. natural gas combined cycle fleet was 44 percent in 2012, rising to 64 percent after redispatch. These numbers can be readily calculated from the NGCC generation and capacity rating data in the EPA's GDC spreadsheet. The EPA's capacity factor estimate after redispatch is quite similar to the 65 percent average capacity factor for NGCC facilities estimated to result from CATF's Power Switch approach. While normalizing the two estimates to reflect summer capacity ratings (as opposed to the nameplate rating used by the EPA) would raise the EPA's estimate to some extent, the Power Switch approach was not intended to maximize redispatch from either a technical or economic perspective. Increasing the stringency of the Power Switch approach would also result higher NGCC capacity factors.

target-setting, by allowing affected states and facility owners to comply using the least cost emission avoidance strategies available on the electric system. A trading program also would help mitigate any localized system reliability concerns, as the owners of facilities in constrained areas would be able to purchase of emission allowances from affected facilities in states with greater opportunities for natural gas redispatch.

v. The seasonal pattern of demand for natural gas transportation services, current efforts to address peak day infrastructure constraints and the flexibility of compliance provisions under the proposed rule all support the stringency of building block 2.

Commenters have suggested that EPA's building block 2 assumptions are unrealistic due to existing constraints in natural gas supply, which would result in an inability to meet the level of gas redispatch the Agency predicts.[200] We disagree. While gas transport constraints exist during some peak demand days in some regions of the country, transport capacity is still available for redispatch in unconstrained regions and off peak times of the year.[201] Natural gas consumption in the U.S. peaks during the winter home heating season and inter-state gas pipeline capacity is often fully utilized during at least some of that season.[202] In other times of the year when gas consumption is lower, unless it is used to fill market-area storage or for other purposes, pipeline capacity is often available.[203] This capacity could allow existing NGCC units to increase generating output without infrastructure expansion.

The availability of transport capacity is illustrated by four sets of mapped results from the draft Eastern Interconnection Planning Collaborative ("EIPC")[204] Target 2 Report. The Target 2

---

[200] Comments submitted by Anda Ray, Vice President, Environment and Chief Sustainability Officer, Electrical Power Research Institute, EPA-HQ-OAR-2013-0602-21697
(Oct. 20, 2014)**;** Steve Corneli, Senior Vice President, Policy & Strategy, NRG Energy "Glide Paths Instead of Cliffs: Greater Emission Reductions at Lower Cost" Doc. ID: EPA-HQ-OAR-2013-0602-17281.

[201] U.S. EIA, "Natural Gas Pipeline Capacity & Utilization," *available at* http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/usage.html.

[202] U.S. EIA "Trends in Natural Gas Storage Capacity Utilization Vary by Region," *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=12811.

[203] U.S. EIA, "Natural Gas Pipeline Network: Changing and Growing," *available at* http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_trends/pdf/chapter5.pdf

[204] According to the Target 1 Report: The Eastern Interconnection Planning Collaborative (EIPC) was formed in 2009 by 25 of the major eastern electric utilities, in order to complete work awarded to the PJM Interconnection, LLC (PJM) on "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009. The work was divided into two phases. Phase 1 focused on the formation of a diverse stakeholder group (the Stakeholder Steering Committee) and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the stakeholder group. The final undertaking in Phase 1 was for the stakeholder group to choose three futures scenarios to pass onto Phase 2 of the project. Phase 2 of this project focused on conducting the transmission studies and production cost analyses on the three scenarios chosen by the stakeholders at the end of Phase 1. This work included developing transmission options, performing a number of studies regarding grid reliability and production costs resulting from the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

report of the EIPC's DOE project, "*Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems"* evaluates the ability of the natural gas systems in the study region to meet the demand of end use and gas-fired electric generation customers over 5-year and 10-year planning horizons. The primary goals of the Target 2 research are to develop a chronological dispatch model of the electric system; incorporate forecasts of generator gas demand with forecasts of end use gas demand and represent seasonal peak days at the five-year and ten-year horizons across the Study Region; identify gas system infrastructure constraint points and evaluate infrastructure adequacy to meet generation gas demand on seasonal peak days; and determine potential mitigation measures to address gas system infrastructure constraints.

The EIPC maps labeled Winter 2023 – Reference Gas Demand Scenario and Winter 2023 High Gas Demand Scenario show pipeline capacity conditions during a peak winter day, one under a reference gas demand scenario and the second under a high gas demand scenario in modeled year 2023.[205] Fully utilized pipeline segments are shown in red), and the total extent of red pipelines is not dramatically different as between the two Winter 2023 scenarios. Furthermore, there are natural gas pipeline systems not fully utilized under either set of Winter peak day conditions, shown by the green and yellow pipelines.

EIPC, Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces ") at xiv, *available at*: http://www.eipconline.com/uploads/Target_1_Report_Final_Draft_4Apr14.pdf.

[205]The reference gas demand scenario represents a forecast that is in accord with the economic, market, and regulatory assumptions characterizing the resource planning process of each of the power producing areas over the five- and ten-year study horizons. The high gas demand scenario represents a plausible maximum level and profile of gas requirements across the Study Region, driven primarily by increased deactivation or retirement of coal plants, lower delivered natural gas prices, and higher electric loads.

.

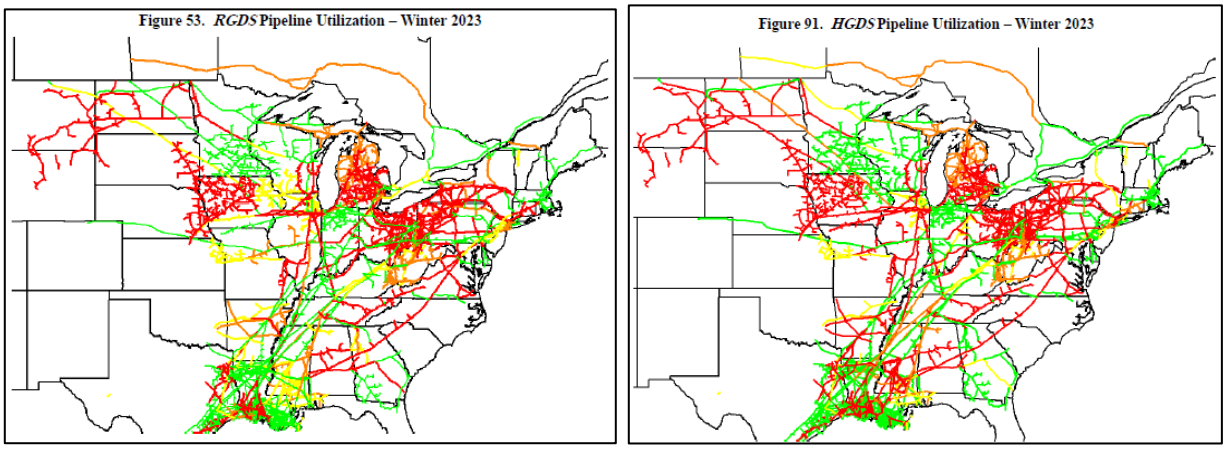


Figure 16: Winter 2023 – Reference Gas Demand Scenario Winter 2023 – High Gas Demand Scenario (Source: EIPC, *Target 2 Draft Report*, at 73 *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

The second set of maps shows EIPC's modeled peak summer day pipeline conditions. When compared with the winter peak conditions under both the Reference Gas Demand Scenario and the High Gas Demand Scenario, it is clear that there are predicted to be many fewer fully utilized pipeline systems in the summer months, under either scenario.

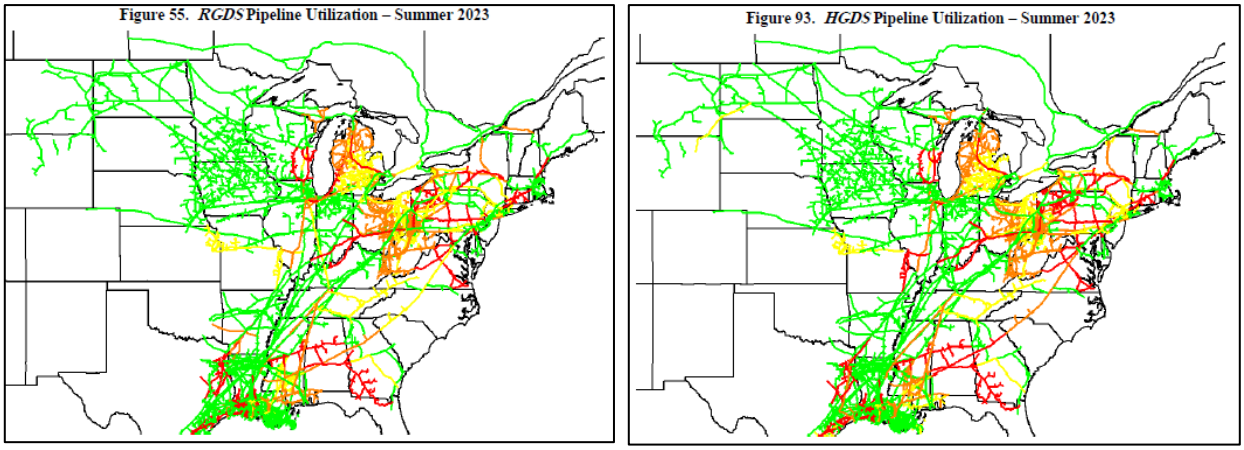


Figure 17: Summer 2023 – Reference Gas Demand Scenario Summer 2023 – High Gas Demand Scenario (Source: EIPC, *Target 2 Draft Report*, at 103, 1095 *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

Concerns regarding gas deliverability and electric supply in New England are not representative of electric-gas conditions across the country. EIPC's Target 1 Report, titled "*Baseline Existing Natural Gas-Electric System Interfaces"* includes the figure below. The report notes that: "Green represents favorable gas-electric interface conditions relative to the other power producing areas (PPAs), that is, the absence of pressing concerns regarding the gas-electric interface capability operational available to generation companies. Yellow represents

neutral conditions, that is, conditions not clearly favorable or unfavorable to generation companies. Red represents comparatively unfavorable conditions."[206]

Table 3. Qualitative Assessment of Gas – Electric Interface Attributes

	Criterion	PJM	MISO	NYISO	ISO-NE	TVA	IESO
Natural Gas Supply	Gas Supply Portfolio Diversity						
	Pipeline Connectivity Level						
	Conventional Storage Deliverability						
	LNG Storage Capability						
Electric-Gas Interface	Firm Transportation Entitlements						
	Direct Pipeline Connectivity						
Electric/Gas Tariff	Pipeline or LDC Penalties						
	LDC Provision of Flexible Service						
	Active Secondary Market						

Table 7: Qualitative Assessments of Gas-Electric Interface Attributes (Source: EIPC, Target 1 Report, *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

The gas and electric industries, along with federal and state regulators, are engaged in multiple efforts to assess and, where needed, bolster the adequacy of fuel transport and storage systems.[207] For this reason alone, it is likely that any critical infrastructure constraints can be addressed.

Moreover, the proposed rule provides flexibility for states to comply by allowing them to average the CO_2 emissions rate associated with affected units across a state, within a year, for each year during the 2020 to 2029 period. EPA's rule can be implemented through a mass-based allowance system, under which emissions allowances can be traded on an interstate basis with other states, as we recommend, and discuss more fully *infra* at Sec. III. All of this suggests that the existence of a current infrastructure constraint need not preclude CO_2 reduction through redispatch.

vi. Both historical data and forecast analyses suggest the 64 percent average NGCC utilization factor and 70 percent maximum NGCC utilization factor relied on by EPA in goal setting are reasonable.

[206] Target 1 Report at ES-19 – ES-22 http://www.eipconline.com/Gas-Electric_Documents.html.

[207] *See generally* FERC, "Major Pipeline Projects Pending" (June 15, 2014), *available at*: http://www.ferc.gov/industries/gas/indus-act/pipelines/horizon-pipe.pdf; New York Independent System Operator (NYISO), "Proposed Gas Electric Study Scope (Mar. 2012): Study of the Adequacy and Security of the Interaction of the Gas and Electric Systems in the Northeastern US, Midwest US, and Ontario, Canada," *available at* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_egcwg/meeting_materials/2012-03-27/Multi-Regional_Electric_Gas_SOW_030812_Final_Draft__2_.pdf; *See also* Tim Maverick, *Changing Gas Sources Present Rare Opportunity*, WALL ST. DAILY (Oct. 15, 2014), available at: http://www.wallstreetdaily.com/2014/10/15/natural-gas-pipeline/.

EPA's building block 2 estimates the CO_2 reductions achievable based on the redispatch of generation from higher to lower emitting affected units – that is, from coal to NGCC plants in each state. If it is assumed that only designated facilities are redispatched, the amount of CO_2 reduction is directly related to the amount of coal generation in 2012, and the incremental generation available to be generated by NGCC plants existing and under construction as of 2012 when operated at a 70 percent annual utilization factor,[208] rather than the 44 percent utilization factor experienced in 2012. Since the additional NGCC generation available in some states is greater than 2012 coal generation, this methodology results in an average utilization factor for existing and under construction NGCC capacity of 64 percent and total redispatched generation of 438 TWh. And because even older existing NGCC units emit only half as much CO_2 as would generating the same amount of electricity by burning coal, ramping up NGCC generation and backing down coal generation this amount yields significant CO_2 emission reductions from existing sources.

Historical capacity and generation data from the Ventyx Velocity Suite shows the NGCC fleet historically has achieved utilization factors equal or close to the 64 percent average utilization factor and 70 percent maximum utilization factor assumed in EPA's building block 2. The U.S. NGCC fleet has operated at a 60 percent utilization factor on a week-long basis, just four percentage points shy of the average utilization factor in EPA's methodology. [209] Similarly, it has operated at 58 percent utilization on a month-long basis,[210] just six percentage points lower than the 64 percent utilization factor EPA assumes. Figure 18 below illustrates this. All six regions of the country have achieved weekly utilization factors of 62 percent to 66 percent, close to or above the 64 percent average utilization factor. The six regions have also achieved monthly utilization factors between 55 and 64 percent.

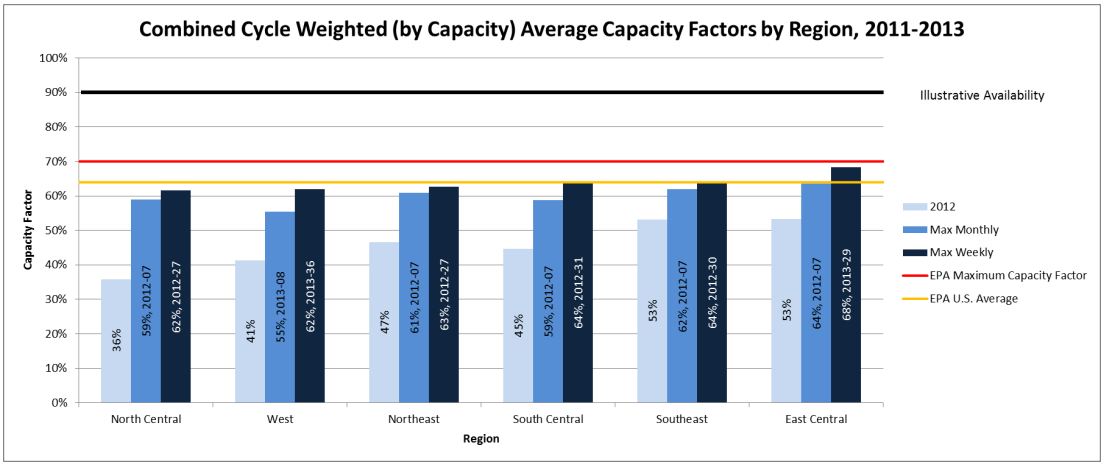


Figure 18: (Source: NorthBridge Group analysis based on data from the Ventyx Velocity Suite).

[208] 79 Fed. Reg. at 34,857. The 70 percent maximum utilization factor is based on the observation that, in 2012, 10 percent of NGCC plants operated at an annual utilization factor of 70 percent or higher.

[209] *Id.* at 34,857.

[210] *Id.* at 34,865.

In addition, Figure 19 shows that The NGCC fleets in 25 of 41 states with NGCC capacity have operated at a weekly utilization factor of 64 percent or higher. Similarly, 16 states have operated at a monthly utilization factor of at least 64 percent.

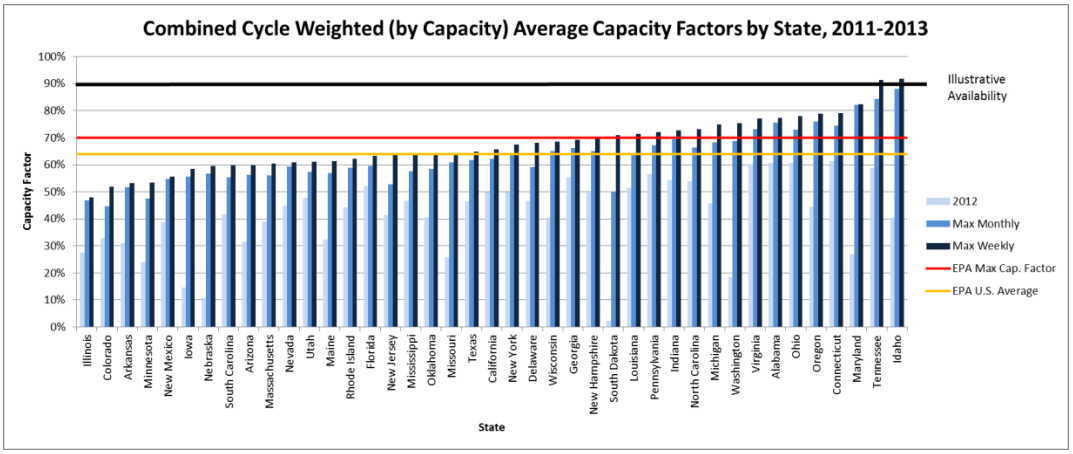


Figure 19: (Source: NorthBridge Group analysis based on data from the Ventyx Velocity Suite).

Forecasts show the potential to redispatch coal to NGCC generation within the existing fossil fleet and energy system infrastructure. The MIT Future of Gas study in 2011 reported the results of modeling case estimating the availability of redispatch and associated CO_2 emissions reduction between the existing goal and gas fleet in the country. That study found approximately 420 million metric tons of CO_2 could be reduced, by displacing 700 TWh of coal generation, through redispatch of NGCC. The study found an 87 percent capacity factor for these natural gas units.[211]

A recent "bottom-up" analysis of the potential carbon mitigation from redispatching the fleet of coal generating units to NGCCs by researchers at the National Renewable Energy Laboratory ("NREL") found that this strategy holds the technical potential to mitigate over 500 million metric tons of CO_2, or about 25 percent of the power sector's total emissions in 2012.[212] The study found that over 300 million metric tons of CO_2 could be avoided at EPA's proposed 70 percent NGCC utilization "ceiling."[213]

vii. NGCC Air Emission Permit Limitations Should not Limit the Availability of Re-dispatch.

CATF explored our hypothesis that the amount of existing NGCC redispatch contemplated by the state goal calculation methodology in building block 2 and in EPA's compliance modeling analysis is not limited by constraints in air permits limiting the number of

[211] MIT, The Future of Natural Gas (2011) *available at*: https://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

[212] Rachel Gelman, *et al*., *Carbon Mitigation from Fuel-Switching in the U.S. Power Sector: State, Regional, and National Potentials*, 27 ELEC. J. 63-72 *available at*: http://www.researchgate.net/publication/265337856_Carbon_Mitigation_from_Fuel-Switching_in_the_U.S._Power_Sector_State_Regional_and_National_Potentials.

[213] *Id.*

hours per year that existing NGCC units can run. Specifically, we investigated whether NGCC units located in ozone nonattainment areas may have taken run restrictions or tonnage limitations in order to limit their emissions of nitrogen oxides ("NO_x") and/or to achieve "synthetic minor" status in order to avoid major source permitting requirements and Title V fees.[214]

CATF examined a sampling of NGCC operating permits in ozone nonattainment areas. (*See* Attached at Ex. 12). Of the permits evaluated, sixteen appear to have no NOx emissions standards or fuel use restrictions that would limit their annual operations. One facility in Arkansas (170 MW) has an annual NOx limit that appears to limit the facility's annual operations. If the facility were retrofit with advanced NOx controls, it may be capable of additional annual operations. Its permit indicates that it only has low NOx burners installed for NOx control. A second facility in Colorado also appears to have an annual NOx limit that would constrain its annual operations. This facility has a relatively high NOx emission rate, according to EPA's Clean Air Markets database. It appears that the units could run more if their NOx emission rates were lower or the facility limited its supplemental duct firing. To select our sample, CATF applied four "screening" criteria: the unit had to be in (1) an ozone nonattainment area; (2) a state in which government officials have expressed opposition to the CPP; (3) a state with significant NGCC capacity; and (4) a state for which air permits are available online. CATF identified the following ozone nonattainment areas based on both the 1997 and 2008 ozone standards (see nonattainment maps and table below):[215]

[214] A synthetic minor source is an air pollution source that has the potential to emit air pollutants in quantities at or above the major source threshold levels but has accepted federally enforceable limitations to keep the emissions below such levels. 40 C.F.R. § 49.158.

[215] U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/.

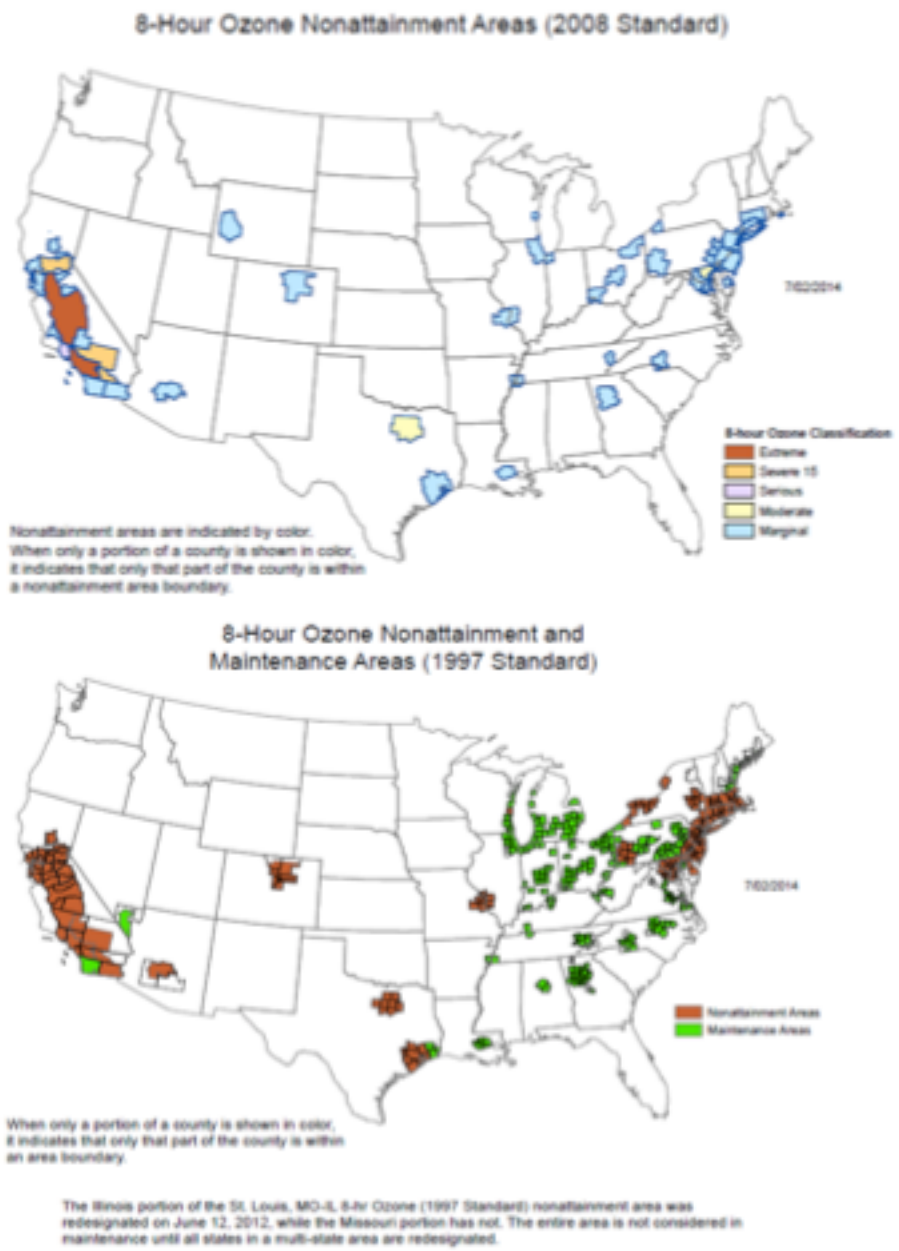


Figure 20: (Source: U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/)

Table 8: Ozone Nonattainment by State (Source: CATF table using U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/).

States	8-hour Ozone Nonattainment (2008)	8-hour Ozone Nonattainment (1997)
Arizona	X	X
Arkansas	X	
California	X	X
Colorado	X	X
Connecticut	X	X
Delaware	X	X
District of Columbia	X	X
Georgia	X	
Illinois	X	
Indiana	X	
Kentucky	X	
Louisiana	X	
Maryland	X	X
Massachusetts	X	X
Mississippi	X	
Missouri	X	X
New Jersey	X	X
New York	X	X
North Carolina	X	
Ohio	X	
Pennsylvania	X	X
Rhode Island		X
South Carolina	X	
Tennessee	X	
Texas	X	X
Virginia	X	X
Wisconsin	X	X
Wyoming	X	

CATF then identified the states whose political leadership has expressed opposition to the proposed CPP based on whether: (1) the state Attorney General signed the white paper: "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act"[216]; (2) the state legislature passed legislation or resolution for state standards or opposing the proposal; or (3) public statements in opposition by lead state environmental officials. The results are expressed in the table below.

[216] Letter from Jon Bruning, Attorney General of Nebraska to Regina McCarthy, Administrator of the U.S. Environmental Protection Agency (Sept. 11, 2013) attaching "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act" *available at*: http://www.nationaljournal.com/free/document/4554.

Table 9: (Source: CATF)

States with Expressions of Opposition	AG Signed White Paper: "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act"	Passed Legislation or Resolution for State Standards or Opposing Proposal	Public Statements of Lead Environmental Officials
Alabama	X		
Alaska	X		
Arizona	X		
Arkansas		X (I.R. 2013-007)	
Florida	X		
Georgia	X		
Illinois		X (HR 0782)	
Indiana	X	X (HR 11- within the fence)	
Kansas	X		
Kentucky	X		
Louisiana	X		
Michigan	X		
Missouri			
Montana	X		
Nebraska	X		
North Dakota	X		
Ohio	X	X (H.B. No. 506- within the fence)	
Oklahoma	X		
South Carolina	X		
South Dakota	X		
Texas			X
West Virginia	X		
Wisconsin	X		
Wyoming	X		

We then ranked the states that met criteria 1 and 2 by existing NGCC capacity:

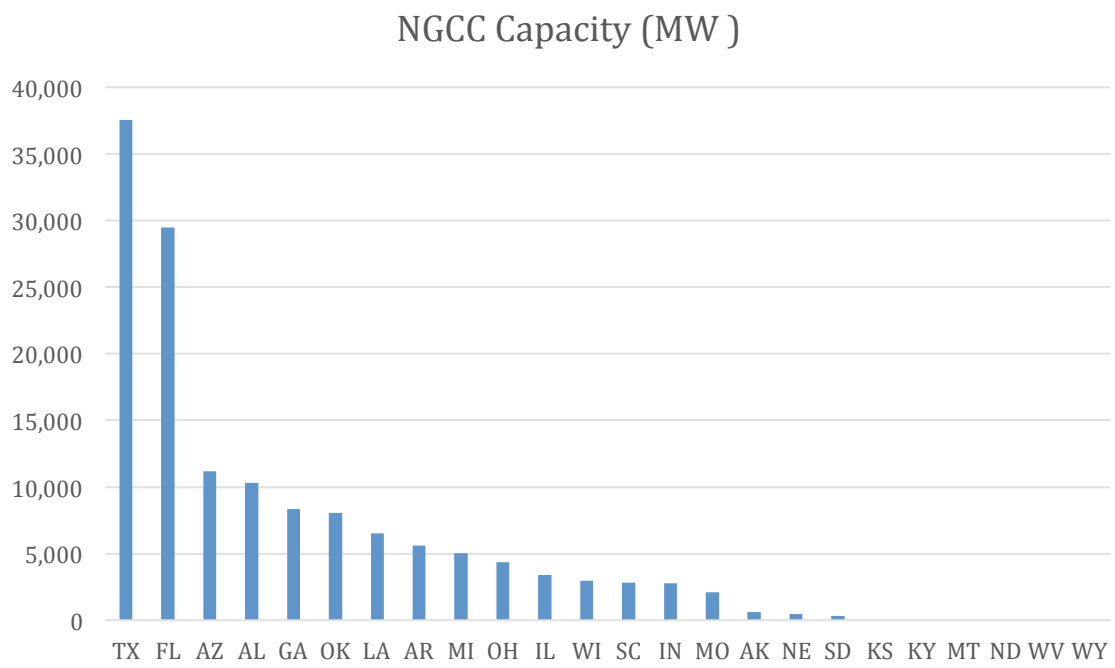


Figure 21: (Source: CATF).

Lastly, after determining the states that met criteria 1-3, we determined which states had online permit access. The results are displayed in the table below:

Table 10: (Source: CATF).

States	Total MW of NGCC	8-hour Ozone Non-attainment (2008)	8-hour Ozone Non-attainment (1997)	Meets criteria 1-3	Permits Available Online
Arizona	11,202	X	X	Yes	Partial
Arkansas	5,588	X		Yes	Yes
Colorado[1]	3,315	X	X	Yes	Yes[2]
Georgia	8,355	X		Yes	Yes
Illinois	3,396	X		Yes	Yes[2]
Indiana	2,768	X			
Louisiana	6,508	X		Yes	Not Identified
Missouri	2,079	X	X		
New Jersey[1]	5,832	X	X		No
Ohio	4,343	X		Yes	Yes
Pennsylvania[1]	9,582	X	X		No
South Carolina	2,839	X			
Texas	37,548	X	X	Yes	Partial
Wisconsin	2,977	X	X		

From this list, we chose those states that met the first two criteria, had the highest NGCC capacity, and had available (online) access to air permits. Those states are: Arizona, Arkansas, Colorado, Georgia, Ohio, and Texas. We obtained the 18 permits that were available for NGCC units located in nonattainment areas in these states. Our examination found that of those 18 permits, only two contained permit restrictions that might constrain its availability to run for re-dispatch at below an 70 percent annual utilization factor and installation of NOx controls would allow both of them to run at utilization factor greater than 70 percent.[217]

In sum, our examination of available permit "headroom" in underutilized NGCC units strongly indicates that these units' air permits do not contain restrictions that would create a barrier to the level of natural gas redispatch EPA has assumed in building block 2 or in its compliance modeling.

viii. If EPA finalizes target rates based on redispatch phased in over a number of years, the starting point for EPA's revised analysis of the CO_2 effects of redispatch in 2020 should be no lower than the historical maximum capacity factor for NGCC.

In the NODA, EPA highlighted a proposal made by commenters concerned that states will not be able to redispatch coal to gas quickly enough to meet the interim state goals.[218] Commenters propose that EPA phase in building block 2 over time as they do with building

[217] The JM Shafer Generating Station, a combined heat and power facility in Colorado, is subject to an annual plant wide NOx emission limit of 589 tons/year. Our examination of the permit found that the plant could be limited to 55 percent annual utilization if the units with the larger rated duct burners are used exclusively.

[218] 79 Fed. Reg. 64,543, 64,545 (Oct. 30, 2014).

blocks 3 and 4 based on growth rates accounting for infrastructure construction and the book life of existing coal-fired power plans.[219] EPA requested comment on other "specific potential rationales for phasing in dispatch changes under building block 2."[220]

If the EPA finalizes targets based on the phase in of building block 2 redispatch over a number of years, the Agency will need to determine the amount of utilization shift (or put differently, the NGCC capacity factor achievable) by 2020. We recommend that EPA select a maximum utilization/capacity factor that is no lower than the level that each state or region has achieved historically. Specifically, the Agency should use the average of the highest monthly utilization/capacity factors achieved during the winter and summer seasons during the years 2011 through 2013 in calculating the portion of the CO_2 emissions reductions targets achievable through building block 2 redispatch. That would reflect the times of greatest NGCC production during the multi-year period about which the Agency has real information, and would also take into account the differing availability of pipeline capacity during the winter and summer seasons.

ix. Modifying building block 2 to account for interstate redispatch opportunities would deepen the emissions reductions available from this rule.

EPA's proposed methodology calculates redispatched generation assuming each state is an island – that is, each state must have the existing NGCC capacity to increase output in the amount needed to reduce emissions from existing coal units in the same state. This metric unfortunately ignores the reality of interstate power flows (which EPA elsewhere recognizes). It therefore misses an opportunity for NGCC generation in one state to displace coal generation in a neighboring state. Calculating redispatch on a regional basis instead of state-by-state would increase the amount of redispatched generation by 104 TWh (or 24 percent).

As noted *supra* Sec. II.a.v, EPA's section 111(d) rules permit the Agency to recommend the contours of an allowance system that could be adopted by multiple states. Many states have asked for such guidance, and we discuss our perspective on the appropriate contours for such a system, *infra* at Sec. III. That approach would allow EPA to better reflect the interstate nature of the industry it is regulating, and would demand an approach to building block 2 that reflects the availability of NGCC capacity for redispatch not only in the same state with the coal units at which utilization is reduced, but also in the states in the same region with the state in question.

x. Building block 2 assumes future increased reliance on natural gas, making even more imperative the need to regulate methane emissions from natural gas production activities.

While EPA's proposal would achieve critical reductions of CO_2 from the largest contributor to that pollutant (fossil fueled power plants), the proposal would also highlight the need to reduce methane emissions from the oil and natural gas sector, the nation's largest industrial source of methane. Any increased usage of natural gas for electricity generation projected to occur under EPA's proposal suggests a strong likelihood that there will be increased methane emissions – including leaks – associated with oil and gas production, processing,

[219] *Id.* at 64,548.

[220] *Id.*

transmission, storage, and distribution. The current Federal regulations addressing these sources do not directly address the methane problem, focusing only on controlling volatile organic compound emissions from some – but not all – new sources; existing sources are free to operate unabated. As a result, the industry can continue wasteful practices in many segments of the industry.

Fortunately, as EPA is aware, opportunities exist *today* to mitigate emissions from this sector in manners that not only represent a very reasonable cost for industry but that also reduce other harmful pollutants like ozone, benzene and toluene. The Agency is currently evaluating responses to White Papers from five of the highest methane emitting sources.[221] The White Papers show that measures are available now to reduce these emissions. Indeed, we estimate that EPA can eliminate up to half of the methane pollution from the oil and gas industry in just a few years.[222] Because natural gas is primarily composed of methane, capturing it actually ensures that more natural gas reaches market (as opposed to wasted to the atmosphere). Thus, many of the methane control measures pay for themselves in a relatively short time period.

Any increased dependence on natural gas as an electricity generation fuel must be accompanied by regulations directly addressing and reducing methane emissions from the oil and natural gas sector. Without such regulations, the sector's methane emissions threaten to erode the projected climate benefits of EPA's current proposal.

c. Building block 3 is overly conservative. The assumptions are incorrect, and EPA inaccurately assumes that biomass is zero carbon-emitting. New natural gas units should also be included.

i. EPA's nuclear assumptions are overly conservative: A more appropriate assumption assumes continued U.S. reliance on nuclear Energy or other non-emitting generation at levels more closely approximating current levels.

Existing nuclear power plants currently provide more than 19 percent of US electricity and more than 63 percent of US emission-free electricity generation.[223]

Existing nuclear power plants will eventually need to be replaced as they retire, and it is critical to reducing U.S. CO_2 emissions that they are replaced with equally non-emitting energy technologies, whether they are nuclear, renewable, hydroelectric, or fossil with CCS.

EPA has recognized the importance of maintaining the existing level of renewable zero-emitting generation by including 100 percent of existing renewable energy in the 2012 baseline

---

[221] *See* U.S. EPA, Oil and Natural Gas Air Pollution Standards: White Papers on Methane and VOC Emissions a*vailable at* http://www.epa.gov/airquality/oilandgas/whitepapers.html.

[222] *See* Clean Air Task Force *et al*., Report Summary, *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry* (Nov. 2014), *available at*: http://catf.us/resources/publications/files/WasteNot_Summary.pdf.

[223] EIA, *Electric Power Annual*, (Dec. 12, 2013), *available at*: http://www.eia.gov/electricity/annual/pdf/epa.pdf. In discussing "emission-free generation," we include wind, solar PV, solar thermal, geothermal, and hydroelectric.

for goal-setting, but that only protects about 15 percent of the country's low or zero-carbon generation. To better recognize existing conditions in 2012, as well as the likely future, EPA should also include 100 percent of existing nuclear in the 2012 baseline.

Nuclear energy and hydroelectric generation represent about 85 percent of current low- or zero-emitting resources, and all of the megawatts produced by nuclear and hydroelectric generation are zero-emitting. Of the existing zero-emitting capacity (including nuclear, hydroelectric, solar, wind, and geothermal), 81.3 percent can be replaced (under the current formulation) with generation that emits at a rate equal to the state's goal rate –which will lead to CO_2 emissions *increases* representing a huge step backwards from the starting CO_2 emissions rate of zero for these technologies– and resulting from this rule.[224]

So, while EPA's rates are reasonable in that they reflect an easily achievable target in this regard, they do not go far enough, and in fact may create incentives to *increase* CO_2 emissions. To fix this problem, if EPA is going to continue to rely on building block 3 as any part of the basis for its targets, the Agency will need to adjust the nuclear portion of its building block 3 assumptions to more accurately reflect current and expected future conditions in the industry.

Additionally, analysis by Justin Knowles and Remy Devoe[225], reveals that the current formulation of the building block 3 portion of the BSER target setting exercise actually rewards 15 states with lower apparent (calculated) target emissions rates if they shut down their nuclear power generation and replace it with natural gas generation, than the rates they would have if more realistic nuclear scenarios were used in the target setting exercise.

In Illinois, for example, the current target CO_2 emission rate calculated by the EPA, based on including 5.8 percent of nuclear power in the baseline, is 1,271 lbs./MWh. If Illinois were to take its nuclear capacity offline and replace it with natural gas generation, its resulting emissions rate as calculated by the EPA would be 1,130 lbs./MWh, despite the fact that the state's absolute CO_2 emissions would have risen by 48.4 percent (considered on a mass basis, they would go from 163.7 million tons CO_2 per year to 242.9 million tons CO_2 per year). Thus Illinois can drastically increase its actual emissions, and yet still meet or exceed its EPA state target emission rate.

A similar situation exists for 14 additional states, as illustrated by the Knowles and Devoe analysis. In all states with nuclear generation, the importance of nuclear generation in maintaining and lowering CO_2 emissions is undervalued by the current baseline calculation. The existing methodology leaves absolute emission reductions highly vulnerable to the loss of nuclear power generation by omitting its contribution in the goal-setting step. Therefore, CATF recommends that the EPA include 100 percent of existing nuclear generation in the building block 3 BSER baseline emission rate calculation -- and in the other elements of the target setting methodology -- removing the incentive to retire existing nuclear generation and replace it with higher emitting generating resources.

---

[224] 5.8 percent of existing nuclear is arbitrarily included in the baseline, which represents 3.7 percent of emission-free generation. This, plus renewable generation (solar, wind, and geothermal), protects 18.7 percent of zero-emission generation, leaving 81.3 percent (nuclear and hydroelectric) vulnerable to replacement with emitting generation.

[225] Remy Devow, Unintended Anti-Nuclear Consequences Lurking in the EPA Clean Power Plan, (Aug, 20, 2014), *available at*: http://ansnuclearcafe.org/2014/08/20/unintend-consequences-lurking-in-epa-clean-power-plan/.

ii. EPA's treatment of biomass is internally inconsistent, contrary to scientific consensus about the climate impacts of biogenic emissions, and contrary to law.

EPA's plan to reduce CO_2 emissions from existing fossil-fired EGUs is undermined by the problematic approach to biomass-based electricity taken in the proposed CPP and related materials. Each of the problems described below must be corrected in the final rule.

First, EPA's proposed process for setting state emission targets wrongly assumes that biomass power production is inherently carbon-neutral: One element of the best system of emission reduction for EPA's CPP is increased reliance on renewable and nuclear generation. This is reasonable to the extent that renewable energy ("RE") generation displaces generation at the affected sources thereby decreasing CO_2 emissions. However, in setting the baseline and targets for the CPP, EPA included biomass in RE and simply assumed that burning biomass does not lead to CO_2 emissions. Therefore, when EPA projects that a megawatt ("MW") generated at a biomass-fueled EGU will displace a MW generated by an affected source, the Agency assumes that the affected source's CO_2 emissions will be entirely offset.

EPA's assumption is wrong. By presuming that biomass combustion is "carbon-neutral"—i.e., that biomass-burning EGUs' net contribution of CO_2 to the atmosphere is zero—EPA's proposed approach contradicts scientific consensus, the analysis and recommendations made by an expert panel convened by EPA's Science Advisory Board, and statements made by EPA elsewhere.

Second, biomass co-firing is not a legally permissible method of complying with the CPP: Co-firing with biomass at the affected source actually will increase the amount (and rate) of CO_2 emitted by that source—it certainly will not produce a reduction in that source's emissions—and therefore cannot work as a permissible CPP compliance option. The Clean Air Act requires contemporaneous emission reductions at affected sources and does not permit offsets from future, offsite forest sequestration. The CPP is inconsistent with the CAA and EPA's recently proposed "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units," which regulates all biomass CO_2 emissions from the affected sources.

Third, EPA has not provided states with a legally- and scientifically-valid framework for analyzing the use of biomass as an CPP compliance measure: To the extent that EPA treats biomass-based electricity generation as a compliance measure in the CPP, the Agency must explain how to differentiate between high- and low-CO_2 biomass types to ensure that biomass is treated properly under the CPP. EPA recognizes that states must account for the CO_2 emissions from different types of biomass when complying with CPP (which leads to inconsistencies between the methodology for setting the baseline and targets and the means of complying with the standard), but the Agency's recently revised accounting framework (released on November 19, 2014) does not sufficiently explain how states are to make these distinctions. Worse still, a memo from Acting Assistant Administrator Janet McCabe that accompanied the revised

framework purports to unlawfully exempt emissions from the combustion of certain types of biomass from regulation under Section 111(d), without any showing by the Agency that the use of the exempted biomass will result in net reductions of GHG emissions from affected sources.

Each of these problems with EPA's proposed treatment of biomass energy generation is discussed in further detail below.

1. The proposed process for setting state emission targets wrongly assumes that biomass power is inherently carbon-neutral.

EPA has recognized that "plant growth associated with producing … biomass-derived fuels can, *to varying degrees for different biomass feedstocks*, sequester carbon from the atmosphere" and the preamble to the proposal indicates that states must account for these differences when they *comply* with the CPP.[226] EPA must then also account for these differences associated with biomass in setting the baseline and targets for the CPP if it is to avoid a "critical climate accounting error."[227] EPA's assumption of carbon neutrality for biomass contradicts broad scientific consensus as well as its own statements, and must be corrected.

To determine each state's potential to replace generation from higher-emitting fossil fuel-fired units with RE,[228] EPA started from a baseline of current RE in each state, which it set by adopting "a broad interpretation of RE generation to include any non-fossil renewable type, with the exception of generation from existing hydroelectric power facilities."[229] EPA used 2012 U.S. EIA state level data to characterize the current level of RE generation.[230] The EIA definition of "renewable energy" includes biomass.[231] EPA therefore included existing biomass in the baseline as a zero CO_2 emitting resource, adding only the MW generated through biomass burning into the baseline without any of the associated CO_2 emissions.

In addition to being inconsistent with the scientific consensus on the climate impacts of biomass combustion, the carbon neutrality assumption is haphazardly applied within EPA's proposal. EPA includes the total emissions from four coal EGUs facilities that co-fire biomass in the baseline, even though those facilities did not report their biomass-related emissions.[232] In this

---

[226] 79 Fed. Reg. at 34,924 (emphasis added).

[227] *See* Timothy D. Searchinger *et al.*, *Policy Forum: Fixing a critical climate accounting error*, 326 SCIENCE 527-28 (2009) available at: http://www.sciencemag.org/content/326/5952/527.

[228] EPA's proposed rule sets state goals that gradually reduce the power sector's CO_2 emissions rate. One element of the BSER for the CPP is to reduce the affected sources' CO_2 emissions to the extent that generation can be shifted from higher-emitting, fossil fuel-fired EGU's to lower- or zero-emitting options. 79 Fed. Reg. at 34,835.

[229] *GHG Abatement Measures TSD*, at 4-5.

[230] *Id.*

[231] EIA, Glossary, *available at*: http://www.eia.gov/tools/glossary/index.cfm?id=R.

[232] *Goal Computation TSD*, at 8.

case, EPA used emission rate factors "to estimate stack CO_2 emissions attributable to the type of biomass reported."[233] However, when applying the RE requirements to the baseline, EPA added all existing and new RE generation MW in the state to the denominator without adding any CO_2 emissions to the numerator, treating all RE, including biomass, as zero carbon emitting.[234]

To establish the RE growth factor, EPA divided the country into regions and then averaged the renewable portfolio standard goals of the states within the region, some of which include biomass and other that do not.[235] (EPA recognizes that among the 25 mandatory state renewable portfolio standards "[t]here is considerable diversity among the states in the scope and coverage of these standards, in particular in how renewable resources are defined."[236]) EPA then applied this growth factor to the historic RE baseline in each state to determine the target.[237]

Using biomass as an energy feedstock is not *de facto* carbon neutral; a facility's net carbon emissions depend on the ratio of its actual emissions to forest uptake.[238] EPA recognizes this fact in other sections of the CPP proposal, finding that "[t]he CO_2 reduction potential of biomass co-firing is directly related to the type of biomass co-fired and is due to the difference in heating value, moisture content and hydrogen/carbon ratios for selected biomass fuel compared to the particular coal it replaces."[239] EPA concludes that depending on these characteristics burning biomass "may result in either an increase or decrease in stack CO_2 emission rate."[240]

In addition to being scientifically invalid for the reasons discussed in Sec. III.c.ii.2 below, EPA's carbon-neutrality assumption is inconsistent with the compliance-related approach to biomass that the Agency articulated elsewhere in the proposal. In order to comply with the CPP state targets, the proposed CPP preamble indicates that states *will* have to account for the CO_2 emissions from burning biomass.[241] EPA expects some states will use biomass as part of their compliance plan for the CPP and notes that it is important for EPA to "define a clear path for

---

[233] *Id.*

[234] *Id.* at 15-16.

[235] *GHG Abatement Measures TSD*, at 4-9 to 4-12.

[236] 79 Fed. Reg. at 34,927.

[237] *Id.*

[238] Thomas Helin, *et al.*, *Approach for inclusion of forest carbon cycle in life cycle assessment – a review*, 5 GLOBAL CHANGE BIOLOGY BIOENERGY 475, 476 (2013) [hereinafter "Helin *et al*."] (Ex.5). "The timing difference between the release and sequestration of forest biomass carbon leads to a situation where part of the carbon remains in the atmosphere until it is fully sequestered back into the growing forest. This results in a warming impact if sequestration lags emission."

[239] *GHG Abatement Measures TSD*, at 6-15.

[240] *Id.* at 6-16.

[241] 79 Fed. Reg. at 34,925.

states to do so" (which it has yet to do).[242] EPA refers to the biogenic CO_2 accounting framework under development, which the Agency said would allow states to assess the impact of using biomass fuels to reach emission reduction goal.[243]

Specifically, EPA states:

> Because of the positive attributes of certain biomass-derived fuels, the EPA also recognizes that biomass-derived fuels can play an important role in CO_2 emission reduction strategies. We anticipate that states likely will consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans to meet the emission reduction requirements of this rule, and we think it is important to define a clear path for states to do so.[244]

The proposal lacks a coherent rationale for allowing biomass to serve as a compliance measure in the section 111(d) context, however. Instead, it offers the passage below in which a statement about the importance of protecting and restoring US forest sinks concludes with the italicized *non sequitur* about the potential climate benefits of biomass combustion:

> Through President Obama's Climate Action Plan, the Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. Sustainable forestry and agriculture can improve resiliency to climate change, be part of a national strategy to reduce dependence on fossil fuels, and contribute to climate change mitigation by acting as a "sink" for carbon. The plant growth associated with producing many of the biomass-derived fuels can, to varying degrees for different biomass feedstocks, sequester carbon from the atmosphere. For example, America's forests currently play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. *As a result, broadly speaking, burning biomass-derived fuels for energy recovery can yield climate benefits as compared to burning conventional fossil fuels.*[245]

2. EPA's carbon-neutral assumption contradicts the scientific consensus on the climate impact of biogenic emissions.

[242] *Id*. at 34,924.

[243] *Id*. at 34,925.

[244] *Id*. at 34,924.

[245] *Id*.

The climate implications of harvesting forests for energy generation purposes must reflect, among other things, the resultant losses in available carbon sequestration.[246] In 2013, terrestrial biomass (including soil) removed 23 percent of global CO_2 emissions.[247] The increased use of biomass as a RE resource may "significantly increase the removal of wood from boreal forests, thus decreasing their carbon sink compared with current trends."[248] Claims of biomass carbon neutrality make a "baseline error" by neglecting the CO_2 sequestration that would occur in the absence of exploiting forests for bioenergy.[249] Some studies find that "CO_2 removal by the land sector is essentially recapturing past emissions due to land use or land-use change and therefore does not neutralize fossil fuel emissions" at all.[250]

Science has recognized for decades that "[t]he relative effectiveness of alternative forest and bioenergy strategies and their impact on net [CO_2] emissions strongly depend…on the productivity of the site, its current usage, and the efficiency with which the harvest is used."[251] Bioenergy combustion is not *de facto* carbon neutral and the climate implications of biomass use depend significantly upon the accounting assumptions made.[252] A recent review of biomass carbon accounting approaches recommends consideration of the following factors:

- A reference situation for forestland use has to be defined appropriately;
- Changes in all the different forest stocks, such as stemwood, branches, litter, and soil, need to be considered;
- Different time frames should be considered;
- Special attention should be paid to the consideration and transparent reporting of the uncertainties related to the modeling of future development of biomass stocks; and

---

[246] Stephen R. Mitchell, *et al.*, *Carbon debt and carbon sequestration parity in forest bioenergy production*, 4 GLOBAL CLIMATE BIOLOGY BIOENERGY 818, 819 (2012) (Ex. 6) (using forests for biomass reduces carbon storage without providing an equitable near-term solution).

[247] Global Carbon Project, "Global Carbon Budget," http://www.globalcarbonproject.org/carbonbudget/14/hl-full.htm.

[248] Helin, *et al.* (*citing* Bottcher H, *et al.*, Projection of the future EU forest CO_2 sink as affected by recent bioenergy policies using two advanced forest management models, 4 GLOBAL CHANGE BIOLOGY BIOENERGY 773 (2012)).

[249] *See generally*, Ernst-Detlef *et al.*, *Large-scale bioenergy from additional harvest of forest biomass is neither sustainable nor greenhouse gas neutral*, 4 GLOBAL CLIMATE BIOLOGY BIOENERGY 611 (2012), *available at*: http://soilslab.cfr.washington.edu/publications/Schultze-etal-2012.pdf.

[250] Judith I. Ajani *et al.*, *Comprehensive carbon stock and flow accounting: A national framework to support climate change mitigation policy*, 89 ECOLOGICAL ECON. 61, 62 (2013) *available at*: http://www.sciencedirect.com/science/article/pii/S092180091300030X.

[251] Bernhard Schlamadinger and Gregg Marland, *The role of forest and bioenergy strategies in the global carbon cycle*, 10 BIOMASS AND BIOENERGY 275 (1996) (Ex. 7).

[252] *See generally*, Guiliana Zanchi, *et al.*, *Is woody bioenergy carbon neutral? A comparative assessment of emissions from consumption of woody bioenergy and fossil fuel*, 4 GLOBAL CLIMATE BIOLOGY BIOENERGY 761 (2012) ("Zanchi *et al.*") (Ex. 8) (confirming prior studies that found emissions reductions achieved through substituting bioenergy for fossil fuel use are time-dependent and that bioenergy is not always carbon neutral).

- Cumulative radiative forcing should be taken into account.[253]

The carbon accounting baseline chosen can have a dramatic effect on the emissions attributed to bioenergy.[254] Baselines can be dynamic or static; they can account for business-as-usual based on historic data or can model the assumed forest growth absent bioenergy. A 2014 study looked at the climate implications of wood pellets displacing coal using three different carbon accounting baselines.[255] The results varied widely for the same situation depending on just the baseline utilized.[256] *See* Figure 22 below:

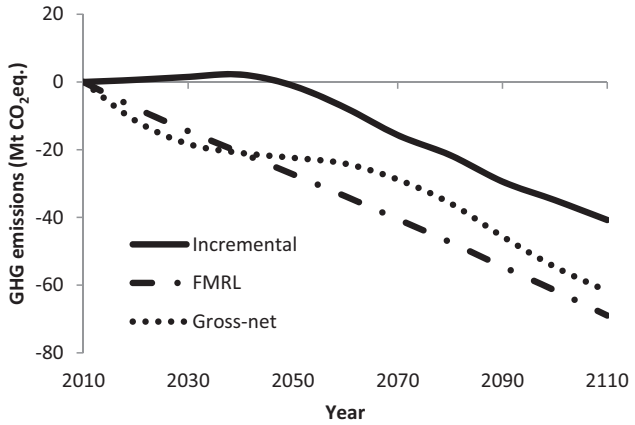


Figure 22: Jon McKechnie, *et al.*, *Forest carbon accounting methods and the consequences of forest bioenergy for national greenhouse gas emissions inventories*, 44 ENVTL. SCI. & POLICY 164, 166 (2014) (Ex. 9).

The climate implications of bioenergy also depend on the source and characteristics of the biomass used for power generation. For example, burning chipped whole trees to generate electricity results in the same, or higher, tons CO_2/MWh output as burning coal. Therefore, it could take a century or more for the carbon sequestration to be replaced,[257] in part because harvest cycles for tree species can range from 60 to 100 years or more due to their slow

---

[253] Helin, *et al.,* at 484 (Ex. 5). *See also generally*, Zanchi, *et al.* (Ex. 8) (discussing the key assumptions that affect the biomass carbon neutrality: time horizon considered; source of the biomass; the productivity of stands; the extent to which management practices are changed; the previous land use; and baseline assumptions).

[254] *See* Jon McKechnie, *et al.*, *Forest carbon accounting methods and the consequences of forest bioenergy for national greenhouse gas emissions inventories*, 44 ENVTL. SCI. & POLICY 164 (2014) ("McKechnie *et al*. (2014)") (Ex. 9).

[255] *Id.* at 166.

[256] *Id*. The three baselines used were: 1) Incremental carbon impact (Incremental) is a forward-looking a dynamic baseline that predicts future forest carbon stocks resulting from ongoing production of conventional wood products but specifically excludes changes in forest carbon due to future harvest for bioenergy; 2) Forest management reference level (FMRL) is a forward-looking and dynamic baseline that predicts future carbon stocks under business as usual forest management assuming future and historical harvest rates to be equal; 3) Gross-net is a static baseline that assumes no change in forest carbon stocks from the level at the start of the commitment period.

[257] Jon McKechie, *et al.*, *Forest Bioenergy or Forest Carbon? Assessing Trade-Offs in Greenhouse Gas Mitigation with Wood-Based Fuels*, 45 ENVTL. SCI. TECH. 789 (2011) ("McKechnie *et al*. (2011)") (Ex. 10).

growth.[258] One study found that the carbon debt for using whole trees from boreal forests could last up to 340 years.[259]

In addition to the baseline and biomass source, the timeframe used to analyze the relationship between carbon emissions from biomass burning and forest regrowth and carbon uptake has significant implications for any accounting factor.

> Emissions and sinks of biomass carbon usually occur at different points in time, particularly in the case of forest biomass use. The timing of emissions and sinks has an impact on the overall cumulative climactic impact on the activity over a certain timeframe. The carbon emission into the atmosphere has a warming impact (radiative forcing), whereas the sequestration has a cooling impact. The carbon debt between emission and sequestration results in a warming effect if sequestration lags emission. As a consequence, the result of the climate impact assessment is dependent on the time horizon of the assessment.[260]

The relative climate benefits of biomass electric generation also depend on the fuel that bioenergy displaces. Replacing CO_2-intensive coal instead of natural gas with biomass would lead to a smaller initial net CO_2 increase and reduce the time before reaching CO_2 parity.[261]

Using biomass in place of fossil fuels for electric generation without appropriately accounting for the factors that affect biomass CO_2 implications would merely transfer emissions from the electric sector to the forest sector without providing actual climate benefits.

EPA has recognized the need to fully account for biogenic emissions, both in this rulemaking and in other regulatory contexts. In 2011, EPA deferred for three years the application of Prevention of Significant Deterioration and Title V permitting for biogenic CO_2.[262] The resulting exemption for biogenic CO_2 – on the basis that biomass burning is a zero-emitting fuel, was subsequently struck down as unreasonable, arbitrary, and capricious by the D.C. Circuit Court of Appeals,[263] because EPA failed to offer an interpretation of the Clean Air Act's

---

[258] *See, e.g.*, Manomet Center for Conservation Sciences, Massachusetts Biomass Sustainability and Carbon Policy Study, *Report to the Commonwealth of Massachusetts Department of Energy Resources (*Walker, ed.) (National Capital Initiative Report No. NCI-2010-03) (2010), *available at*: http://www.mass.gov/eea/docs/doer/renewables/biomass/manomet-biomass-report-full-hirez.pdf (demonstrating using modeling that the combination of greater carbon emissions per unit energy from biomass than fossil fuels, combined with the lost forest sequestration associated with additional fuel harvesting, produce net CO_2 emissions that greatly exceed those from fossil fuels – a "carbon debt" that takes decades to more than a century to pay off).

[259] Bjart Holtsmark, *et al*., *Harvesting in the boreal forests and the biofuel carbon debt*, 112 CLIMATIC CHANGE 415 (2011), *available at*: http://www.ssb.no/a/publikasjoner/pdf/DP/dp637.pdf.

[260] Helin, *et al.* (Ex. 5), at 479.

[261] Jon McKechie, *et al. (2011)* (Ex. 10), at 794.

[262] 76 Fed. Reg. 43,490 (July 20, 2011) [hereinafter "Deferral Rule"].

[263] *Center for Biological Diversity v. EPA*, 722 F.3d 401, 410 (D.C. Cir. 2013).

permitting provisions that allow the Agency to treat biogenic CO_2 sources differently. That improper view of the Act is no different than the assumption EPA has adopted in setting the baseline and targets for the CPP.

In 2011, however, EPA *also* committed to completing a scientific and technical review and a further rulemaking by July 21, 2014 stating, "three years is ample time to complete these tasks."[264] EPA also issued a Draft "Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources," which contained a method for adjusting the total onsite biogenic CO_2 emissions on the "basis of information about growth of the feedstock and/or avoidance of biogenic emissions and more generally the carbon cycle."[265] A year later, in September 2012, EPA's Scientific Advisory Board issued significant comments on the Draft Accounting Framework.[266] More than two years later, and nearly six months after issuing the proposed CPP, and only seven working days before the close of the CPP comment period, EPA issued a revised "Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources."[267] The revised Framework describes criteria that can be used to account for biogenic greenhouse gases, but it does not explain how those criteria must be analyzed in the context of the CPP, or in permitting, or any other practical application. Without a finalized accounting framework each state might count biogenic CO_2 emissions differently, which would undermine effective administration of the CPP. The absence of a final, scientifically- and legally-valid framework is also preventing stakeholders from fully assessing the role of biomass under the CPP.

3. Biomass co-firing is not a legally permissible CPP compliance method because EPA must ensure that designated facilities achieve actual emission reductions.

The CAA section 111(d) program is source-focused, requiring states to submit plans that establish standards of performance for certain existing sources.[268] The CPP regulates subpart Da and subpart KKKK sources, which do not include dedicated biomass facilities. Therefore, dedicated biomass facilities can only be included in state plans for compliance with the CPP to the extent that their generation demonstrably displaces generation at the covered sources and, as a result, the covered sources reduce their emissions sufficiently to comply with the standard of performance.

A standard of performance "reflects the degree of emission limitation achievable through the application of the best system of emission reduction … the Administrator determines has

---

[264] 76 Fed. Reg. at 43,493.

[265] U.S. EPA, "Draft Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources," at 1 (Sept. 2011) [hereinafter "2011 Accounting Framework"].

[266] *Center for Biological Diversity*, 722 F.3d at 410.

[267] U.S. EPA, "Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources," (Nov. 2014), *available at*: http://www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.

[268] 42 U.S.C. § 7411(d)(1)(A).

been adequately demonstrated."[269] The emission reductions typically attributed to biomass-burning EGUs are uncertain, speculative, and dislocated, and cannot be relied upon by designated facilities for the purpose of CPP compliance.

First, with regard to live trees and plants that are harvested for fuel (as opposed to residues), the assumption that net biomass emissions are lower than stack emissions is essentially a claim that emissions are "offset" by future plant growth. Thus, assuming that compensatory and additional planting is not occurring elsewhere, there is no basis whatsoever for claiming a reduction unless plant matter grows back on the land from which the biomass feedstock was harvested[270]—and yet the practice of combusting biomass is only tenuously connected to any subsequent regrowth of plant matter. Second, in the event that regrowth does occur and the CO_2 emitted by a biomass-burning EGU is more or less resequestered, the process takes years, decades, or even centuries. Third, these nominal emission reductions happen in forests and farmland; they do not occur at the designated facility.

Therefore, because the combustion of biomass at designated facilities does not lead to actual, real-time emissions reductions at the designated facilities, it cannot be a standard of performance, which is defined as the best system of *emission reduction*. EPA should make explicit in the final CPP that co-firing biomass at designated facilities is not available for compliance with the emission reduction targets established under the CPP.

EPA's CO_2 NSPS[271] for EGUs counts biogenic CO_2emissions at the stack and requires actual, real-time emission reductions, which must be met at the covered source. Adjusting biogenic CO_2 emissions necessarily requires offsetting emissions through delayed offsite sequestration. Under the CAA and NSPS, EGUs must reduce emissions at the stack and cannot rely on such offsets.

The NSPS applies to new biomass facilities burning more than 10 percent fossil fuel on a three-year average annual heat-input basis.[272] EPA recognized that the net climate impacts of biomass-based energy generation hinges on the type of biomass being combusted and how that biomass was grown, harvested, processed, and combusted.[273] Yet, the proposed CO_2 standards "do not apply a different accounting method for biogenic CO_2 emissions for the purpose of determining compliance with the standards,"[274] because EPA correctly determined that CO_2 emissions emitted from the stack for biomass co-fired with fossil fuel at an affected source must

---

[269] 42 U.S.C. § 7411(a)(1).

[270] And sequesters more carbon than would have been sequestered otherwise. *See, e.g.*, *See* Timothy Searchinger, *Biofuels and the Need for Additional Carbon*, ENVIRON. RES. LETT. 5 (2010) 024007, *available at*: http://iopscience.iop.org/1748-9326/5/2/024007/pdf/1748-9326_5_2_024007.pdf.

[271] 79 Fed. Reg. 1,430 (Jan. 8, 2014).

[272] *Id.* at 1,446.

[273] *Id.*

[274] *Id.*

be entirely counted toward compliance. Emissions are calculated contemporaneously without offsetting for later-in-time sequestration or decomposition.

By contrast, the CPP baseline and target determinations count biomass as emitting zero CO_2 emissions when it is burned, but EPA would use a yet-to-be-determined discount rate when assessing compliance. The difference between the approach taken in the NSPS proposal and the approaches described in the proposed CPP constitutes another inconsistency among the treatment of biomass under the proposed CO_2 standards for EGUs. EPA must require actual, real-time emissions reductions at the affected source under the CPP, not net reductions that *might* occur elsewhere years or decades after biomass is initially burned.

Nor is co-fired biomass as a compliance option properly accounted for under the CPP. As discussed above, the proposal is most properly based on the concept that RE and other lower or zero-emitting generation will displace fossil-based generation, leading directly to reduced utilization at a covered source, which in turn results in lower CO_2 emissions. However, in the case of co-firing biomass at a covered source, the actual, real-time emissions of CO_2 during electricity generation do not decrease; indeed, they typically increase. "[T]he overall net atmospheric contribution of CO_2 resulting from the use of biogenic feedstock by a stationary source, such as an EGU, will ultimately depend on the stationary source process and the type of feedstock used, as well as the conditions under which that feedstock is grown and harvested."[275] Offsets that do not directly lead to actual emissions reductions at the covered sources are not counted under the NSPS and EPA has made it clear that offsets will not be counted unless they lead directly to CO_2 emission reductions at affected EGUs in the CPP: "[E]missions reductions from offsets would not be counted when evaluating CO_2 emission performance of affected EGUs, because those reductions would not come from those affected EGUs."[276] Therefore, biomass offsets in the form of forest regrowth and management, under the control of third parties, fail to achieve CO_2 reductions when co-fired by covered sources, as required by the CAA.

4. EPA has not provided States with a legally- and scientifically-valid framework for analyzing the use of biomass as a CPP compliance measure.

The continuing absence of a final biogenic emissions accounting framework that appropriately differentiates between high- and low-GHG biomass types impairs CATF's ability (and the ability of other stakeholders) to provide detailed comments on the role of biomass in EPA's CPP proposal, other than to say with certainty that all biomass is not zero- CO_2-emitting. It is imperative that EPA promulgates a final, scientifically- and legally-valid accounting framework and take comment on the framework and its interaction with the CPP before finalizing the CPP.

---

[275] *GHG Abatement Measures TSD*, 6-12 n. 274.

[276] U.S. EPA, *Technical Support Document: Projecting EGU CO_2 Emission Performance in State Plans*, at 37, Docket No. ID: EPA-HQ-OAR-2013-0602 (June 2014) [hereinafter *State Plan CO_2 Performance TSD*].

To ensure that its framework is consistent with both the best available science and the requirements of the Clean Air Act, EPA must take into the account the factors, discussed below, including but not limited to the appropriate baseline, time horizon, types and source of biomass.

a. EPA's 2014 "Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources" leaves key issues unresolved.

EPA's "Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources" (November 2014)[277] ("revised Framework"), is a substantial revision of the Agency's flawed 2011 draft framework. EPA expects that the revised Framework will serve two objectives. As a general matter, the document is intended to "continue advancing the Agency's technical understanding of the role the use of biomass can play in reducing overall greenhouse emissions;"[278] more specifically, EPA "expect[s] that many states and stakeholders will look to the second draft of the Framework for indications of how the Agency will treat biogenic CO_2 emissions under both the CPP and the PSD program going forward."[279] The documents do not meet that expectation, however. Although the revised Framework recognizes many of the appropriate criteria for analyzing biogenic greenhouse gas emissions, it fails to provide clear "indications of how the Agency will treat biogenic CO_2 emissions under [the CPP]."

The November 2014 Framework focuses the biogenic GHG accounting process on a set of analytic criteria that is consistent with the recommendations made by an expert panel convened by the Science Advisory Board[280] and in comments submitted by environmental NGO stakeholders.[281] By contrast, under the approach described in the 2011 draft accounting framework, EPA would have based its assessment of a biomass-burning facility's net GHG emissions on whether and to what extent the CO_2 emissions associated with the use of biomass as an energy feedstock exceed the carbon sequestration associated with ongoing forest growth across the surrounding multi-state region. If total forest sequestration in a given region exceeded the emissions from biomass-burning facilities in that region, the 2011 framework indicated that

---

[277] EPA, Revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources (Nov. 2014) ("EPA Revised Framework") http://www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf

[278] EPA, November 2014: Revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources. http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.

[279] Janet G. McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation, "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (November 19, 2014) ("McCabe Memo") at 1. http://www.epa.gov/climatechange/downloads/Biogenic-CO2-Emissions-Memo-111914.pdf.

[280] SAB Review of the Draft Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources (Sept. 28, 2012). http://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument

[281] *See* CATF, Comments on EPA's Call for Information on GHG Emissions Associated with Bioenergy and Other Biogenic Sources (September 2010) and CATF *et al.,* Comments on EPA's 2011 Draft Accounting Framework for Biogenic Emissions (October 2011) (both *available at*: http://www.catf.us/resources/filings/biomass/)

regulators should consider the facilities to be carbon-neutral.[282]

CATF and other organizations criticized the draft Framework in comments provided to EPA:

> At its foundation, EPA's proposal is premised on the logical error that the carbon emissions from bioenergy can be ignored – not because certain sources of bioenergy can reduce emissions, but because bioenergy harvests do not completely overwhelm the forest growth (and associated carbon accumulation) that is already occurring throughout the world. In essence, the proposal would permit biomass-powered stationary sources to use up existing sequestration capacity, and by doing so significantly increase atmospheric greenhouse gas (GHG) levels. The gross forest carbon sink is mitigating climate change today by absorbing roughly one third of human emissions of carbon dioxide. Cutting down forests to a level that sacrifices this sink would have catastrophic implications for the world's climate, as well as its biodiversity and other forest services.[283]

We urged EPA to develop an accounting framework that did not assume carbon neutrality, but would instead:

- Assess biogenic emissions using a baseline that reflects what would have happened in the absence of biomass consumption and combustion for bioenergy production (the "business as usual" case).
- Ensure that all claims concerning GHG emissions reductions are real, verifiable, and additional.
- Assess biogenic emissions and reductions consistently, regardless of the region in which they occur.
- Account for leakage emissions, including those attributable to indirect land use change.[284]

A panel of experts convened by the EPA SAB agreed, having found that EPA's draft accounting framework needed:

> more consideration of different spatial and temporal scales, different baselines to better capture the additional effects of changes in biogenic feedstock use, broader discussions on leakage and soil carbon implications, and the concept of regional

---

[282] *See* EPA, "Draft Accounting Framework for Biogenic CO2 emissions from Stationary Sources" (2011) at 75. http://www.epa.gov/climatechange/Downloads/ghgemissions/Biogenic-CO2-Accounting-Framework-Report-Sept-2011.pdf

[283] CATF, NRDC, Greenpeace, and PFPI, Comments to EPA on "Accounting Framework fir Biogenic CO_2 Emissions from Stationary Sources" (submitted Oct. 18, 2011) (internal citation omitted) at 2-3. http://www.catf.us/resources/filings/biomass/CATF-NRDC-PFPI-Greenpeace%20Comments%20on%20EPA%20Accounting%20Framework%20for%20Biogenic%20CO2_101811.pdf.

[284] *Id*. at 6.

> feedstock-specific calculations and default assessment factor values (rather than individual stationary source-specific assessment factor calculations).[285]

It is true that EPA's newly revised Framework

> includes a more comprehensive discussion and analysis—including detailed technical appendices—on the following topics: (1) baseline approaches; (2) spatial and temporal scale decisions and implications; (3) inclusion of alternative fate analysis for certain feedstocks and methane; (4) leakage; and (5) illustrative regional feedstock-specific calculations using existing data sources and models and resulting example regional biogenic assessment factor values.[286]

But the revised Framework still leaves some significant issues unresolved. For example, it does not compel the use of anticipated baselines, compact timeframes, small spatial scales, or leakage determinations. Instead, it merely lists them among the analytic criteria that regulators *might* apply. Under the revised Framework, the biogenic accounting factor ("BAF") *may* be calculated by comparing the projected emissions in a biomass scenario against an anticipated future baseline[287] over the course of an analytic horizon that is compact enough to significantly reduce uncertainty (*e.g.*, 10-20 years).[288] Likewise, a BAF calculation under the new Framework *can* feature spatial scales small enough to be directly affected by a regulated facility's biomass consumption,[289] and it "*can* accommodate calculations of leakage effects," which EPA recognizes "may be a significant factor in determining net biogenic CO_2 fluxes."[290] None of these approaches are required by the revised Framework, however. Consequently, the revised Framework provides little insight into whether and how EPA will account for biogenic CO_2 in the context of the CPP.

b. The Revised Framework does not adequately prevent States from relying on biomass-based energy systems that will Increase net CO_2 emissions

It is unclear how—or even if—the revised Framework will relate to the CPP. EPA states at the outset that it "has not yet determined how the framework might be applied in any particular regulatory or policy contexts."[291] In most instances, the revised Framework catalogs the various options for analyzing biogenic emissions according to the relevant criteria but fails to

---

[285] EPA Revised Framework at 4.

[286] *Id*. at 4-5.

[287] *Id*. at 28.

[288] *Id*. at 35.

[289] *Id*. at 38.

[290] *Id*. at 46 (emphasis added).

[291] *Id*. at 2.

signal a preference for one approach or another.

Baselines. EPA's revised Framework "examines two baseline approaches"—the reference point baseline and the anticipated baseline—"although other baselines could be used when applying the framework."[292] EPA writes, "There is no single correct answer for which baseline to choose, because different baselines help answer different questions,"[293] thereby avoiding its obligation to explain how reliance on different kinds of baselines comports with the requirements of CAA §111(d) or how different baseline options might affect states' emissions targets and/or compliance determinations.

Temporal Scale. EPA lists a set of factors "that should be taken into account to help determine the most appropriate temporal scale," including feedstock choice, region, data availability, and policy or program application. The timeframe for conducting a net emissions analysis "should align with the specific goals of the policy or program that the framework is applied to (e.g., baseline time frames for initial assessment or renewal of requirements under existing programs)."[294] Although there are key considerations that apply to any regulatory effort designed to reduce GHG emissions in a policy-relevant timeframe (such as the need to limit the uncertainty associated with long-delayed emission reductions), the revised Framework does not express even a general preference between short or long timeframes. As a result, it provides no indication as to which analytic timeframe EPA thinks would best "align with the specific goals of the" CPP. Given that there is no explicit authority under Section 111(d) to treat delayed emission reductions as the equivalent of real-time reductions, EPA's failure to require the use of a shorter timeframe particularly problematic with respect to its CPP proposal.

Spatial Scale. Similarly, EPA highlights the revised Framework's flexibility with respect to spatial scales ("The framework is scalable and can be applied at various spatial scales, from a small scale (plot/entity-level) to global"),[295] but it fails to explain how the use of a particular spatial scale is (or is not) consistent with the requirements of CAA §111(d) or the objectives of its CPP proposal.

Leakage. The revised Framework "can accommodate calculations of leakage effects," but it "does not choose or develop a specific methodology for identifying and evaluating these effects,"[296] either in general or with respect to a particular regulatory program—even though EPA has stated elsewhere that it expects states and stakeholders "will look to the second draft of the Framework for indications of how the Agency will treat biogenic CO_2 emissions under both the CPP and the PSD program going forward."[297] Until EPA explains if it will require the

---

[292] *Id*. at 28.

[293] *Id*.

[294] *Id*. at 35.

[295] *Id*. at 43.

[296] *Id*. at 46.

[297] McCabe Memo at 1.

consideration of leakage effects in the context of the CPP (as it must do), and how it will do so, the Agency has not provided adequate opportunity for stakeholders to analyze and comment on the potential role of biomass in CPP compliance.

If EPA chooses correctly among the options it catalogs in the revised Framework—*i.e.*, if the Agency requires states to account for biogenic emissions using anticipated future baselines, spatial scales that facilitate meaningful distinctions between biomass types, and mechanisms that address leakage—the resulting emissions modeling could reasonably simulate the effect that biogenic emissions will have on the atmosphere during the policy-relevant timeframe (that is, by 2030). But if EPA makes the wrong choices with respect to these analytic criteria, or allows states to make the wrong choices, the analyses that result will be highly misleading.

Furthermore, regardless of the timeframe EPA uses to analyze biogenic emissions,[298] any "netting" or "offsetting" of actual emissions resulting from combustion of biomass at affected sources is inconsistent with the proposed CPP under either an emission rate-based system or a mass allowance-based system. In ether case the standards are set on an annual basis, and, as previously discussed, CO2 emissions at the affected source (and the rate of emissions) will actually increase during the year of biomass combustion (the same will likely be true during the entire period leading to final compliance in 2030). Therefore, no credit may be given for biomass combustion under an emission rate-based approach to CPP compliance, and no allowances may be issued for such activities either.

Consistent with the recommendations that CATF and other environmental organizations have previously provided to EPA,[299] we urge the Agency to clarify in its final CPP rule that any biogenic emission accounting determinations conducted within the context of CAA §111(d) regulations must:

- Rely on an anticipated future baseline to model changes in stored carbon. Regulators must compare emissions from increased biomass harvesting under a "business as usual" baseline to a scenario absent increased biomass demand for bioenergy. This approach will help ensure biomass carbon accounting results reflect what the atmosphere "sees" in terms of emissions.

- Make clear that no credit may be given for biomass combustion under an emission rate-based approach to CPP compliance, nor may mass-based allowances be issued for such activities

- Calculate biogenic emissions and reductions consistently, regardless of the spatial scale or region in which they occur. BAFs should be modeled in a way that is

---

[298] EPA has suggested that biogenic emissions may be analyzed over a protracted timeframe—such as 50 years, see, EPA Revised Framework-Appendix B: Temporal Scale.

[299] *See* Oral Briefing by Natural Resources Defense Council and CATF to EPA Climate Change Division (Nov. 12, 2014).

independent of the physical fuel shed area. Instead, data to inform BAFs – on fuel type, size class for woody biomass feedstocks, land use history, current harvest regime and alternate biomass uses in existing wood products markets – should be collected at the appropriate scale for each class of data.

- Address leakage by incorporating the following counterbalancing assumptions into the BAF analysis: First, that new biomass harvest displaces demand associated with other industries on a full 1-to-1 basis to a new, similar forest stand. And second, that leakage is additive and "new" standing trees are cut in forests that are biologically and climatically identical to the original wood source to meet the original non-biomass needs.

- Categorize biomass feedstocks according to key physical and methodological characteristics. This process includes differentiating between different fuel types (*e.g.*, boles versus branches/limbs), different size classes (*e.g.*, large diameter versus small diameter), different land use histories (*e.g.*, planted versus naturally regenerating); different harvest regimes (*e.g.*, complete removal versus partial cuts); and different alternative fates (*e.g.*, short-term uses versus long-term structural objects for merchantable and *in situ* burning versus decay for harvest residues).

EPA plans to submit the revised Framework to "a second round of targeted peer review through its SAB later this month."[300] While CATF will engage in that process to provide the Agency and the SAB panel with more detailed recommendations about biogenic emissions accounting, we stress that EPA has a *separate* duty with respect to this rulemaking. EPA must explain how biogenic emissions will be accounted for under the final CPP and provide the "critical factual material that is used to justify" that approach.[301] EPA has not yet fulfilled this responsibility.

c. EPA's November 2014 Memo on Addressing Biogenic CO_2 contradicts both law and science.

The memorandum issued by Acting Assistant Administrator Janet McCabe titled "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" ("McCabe Memo"), and accompanying the release of the 2014 Framework draft, outlines EPA's "thinking with respect to [the Clean Power Plan and the Prevention of Significant Deterioration] and their treatment of biogenic CO_2 emissions."[302] Two key assertions in the McCabe Memo are:

- That the "use of waste-derived feedstocks and certain forest-derived industrial byproducts are likely to have minimal or no net atmospheric contributions of biogenic

[300] McCabe Memo at 2.

[301] *See Air Transport Assn v. FAA*, 169 F.3d 1 (D.C. Cir. 1999) ("we have cautioned that the most critical factual material that is used to support the agency's position on review must have been made public in the proceeding and exposed to refutation") (emphasis added).

[302] *Id*. at 1.

CO_2 emissions, or even reduce such impacts, when compared with an alternate fate of disposal." Based on this finding, EPA "expects to recognize the biogenic CO_2emissions and climate policy benefits of waste-derived and certain forest-derived industrial byproducts" when implementing the CPP.[303]

- That EPA also "expects that states' reliance specifically on sustainably-derived agricultural- and forest-derived feedstocks may also be an approval element of their [CPP] compliance plans."[304]

For the reasons detailed below, the McCabe Memo unlawfully exempts certain facilities and/or their emissions from regulation under the CPP. EPA must withdraw the memo, and any future decision to regulate certain type of biomass feedstocks differently from other feedstocks must be accompanied by a full explanation of the legal and scientific bases for doing so.

5. Section 111 requires EPA to ensure that designated facilities achieve actual emission reductions.

Under Section 111 of the Clean Air Act, EPA must develop presumptive emissions standards based on the "degree of emission limitation achievable though the application of the best system of emission reduction…the Administrator determines has been adequately demonstrated,"[305] and require states to submit plans that meet emission the performance standards.[306] Consequently, EPA must require actual *emissions reductions* at the affected source under the CPP.

6. EPA cannot lawfully exempt a designated facility's biogenic CO_2 emissions from regulation under CAA section 111(d) merely because the facility combusts "sustainably-derived feedstocks" without also showing that the result is *de minimis* emissions.

The McCabe Memo indicates that EPA will approve state compliance plans that rely on the use of "sustainably-derived feedstocks" by affected sources that combust biomass, but the memo fails to demonstrate any that (a) the use of those feedstocks reduces emissions consistent with the application of BSER or (b) that the use of those feedstocks will result in GHG emission levels that are *de minimis*.

EPA Has Not Demonstrated that the Use of "Sustainably-Derived Feedstocks" Reduces GHG Emissions Consistent with the Application of BSER. The McCabe Memo "expects that states' reliance specifically on sustainably-derived agricultural- and forest-derived feedstocks may also be an approvable element of their [CPP] compliance plans," and suggests that this

[303] *Id*. at 2.

[304] *Id*.

[305] 42 U.S.C. § 7411(a)(1).

[306] 42 U.S.C. § 7411(d).

course of action is appropriate "given the importance of sustainable land management in achieving the carbon reduction goals of the President's Climate Action Plan."[307]

The use of sustainably harvested feedstocks is not in itself an effective proxy for reducing GHG emissions, or—in the specific case of the CPP—for utilizing the best system of emissions reduction at biomass-burning EGUs. The term "sustainable land management" is used to cover an enormous variety of practices, as are the terms "sustainable forestry" and "sustainable agriculture." A survey of the sustainability requirements promulgated by academic institutions and public and private agencies demonstrates that sustainability definitions and requirements are exceptionally broad and conceptual, and are rarely if ever focused on the GHG emissions that result from the use of "sustainably" grown or harvested biomass. A sampling of examples are excerpted below:

- US Department of Agriculture (USDA): "The term 'sustainable agriculture' (U.S. Code Title 7, Section 3103) means an integrated system of plant and animal production practices having a site-specific application that will over the long term: satisfy human and fiber needs; enhance environmental quality and the natural resource base upon which the agriculture economy depends; make the most efficient use of nonrenewable resources and on-farm resources and integrate, where appropriate, natural biological cycles and controls; sustain the economic viability of farm operations; [and] enhance the quality of life for farmers and society as a whole."[308]

- Programme for the Endorsement of Forest Certification (international NGO "dedicated to promoting sustainable forest management through independent third-party certification"): "Sustainable Forest Management (SFM) means the environmentally appropriate, socially beneficial, and economically viable management of forests for present and future generations ... criteria must be constantly adapted to new circumstances; they must reflect the national context and the specific ecological and environmental conditions."[309]

- Global Environment Facility (GEF): "The most widely intergovernmentally agreed-on language on SFM is represented in the non–legally binding instrument (NLBI) on all types of forests of the United Nations Forum on Forests (UNFF). The GEF fully supports this definition, which states: "Sustainable forest management as a dynamic and evolving concept aims to maintain and enhance the economic, social and environmental value of all types of forests, for the benefit of present and future generations."[310]

- FAO Asia-Pacific Forestry Commission: Sustainable forest management "is the stewardship and use of forests and forest lands in a way, and at a rate, that maintains their

---

[307] *Id*.

[308] USDA, Sustainable Agriculture-Definitions and Terms (http://www.nal.usda.gov/afsic/pubs/terms/srb9902.shtml#toc2).

[309] PEFC, Sustainable Forest Management (http://www.pefc.org/standards/sustainable-forest-management).

[310] GEF, Sustainable Forest Management (SFM)/REDD+ (http://www.thegef.org/gef/SFM).

biological diversity, productivity, regeneration capacity, vitality and their potential to fulfill, now and in the future, relevant ecological economic and social functions, at local, national and global levels, and that does not cause damage on other ecosystems."[311]

If an affected source were to demonstrate that the biomass it utilizes was grown and harvested in a manner that is consistent with the above-listed sustainability regimes, the source might reasonably claim, per the McCabe Memo, that it relies "on sustainably-derived agricultural- and forest-derived feedstocks." But that demonstration would say very little, if anything, about the amount of biogenic CO_2 emitted by the source or the net effect of those emissions on atmospheric CO_2 loading. Consequently, EPA cannot meet its obligations under CAA §111(d) by requiring affected sources to show that they rely on "sustainably-derived feedstocks."

EPA Has Not Demonstrated that the Use of "Sustainably-Derived Feedstocks" Results in De Minimis Levels of GHG Emissions. EPA's plan to treat the use of "sustainably-derived agricultural- and forest-derived feedstocks" as "approvable element of [states'] compliance plans" effectively excludes the resulting emissions from the BSER requirement. However, the Agency has not shown that the biogenic GHG emissions from affected sources that burn "sustainably-derived" biomass are *de minimis* and may therefore be excluded from regulation.

In *Utility Air Regulatory Group v. EPA*, the Supreme Court considered the use of *de minimis* thresholds in the context of the PSD program and confirmed that EPA "may establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions." Before it can avail itself of the *de minimis* doctrine, though, EPA has to establish a "true *de minimis* level" and "must justify its selection on proper grounds."[312]

EPA has made no such showing in the preamble to the CPP proposal, the technical support documents, the revised Framework, or the McCabe Memo. Absent a demonstration that biogenic emissions from affected sources that burn "sustainably-derived" biomass are *de minimis*, EPA must ensure that such sources comply with the requirements of Section 111(d). As described above, the criteria established by EPA in the McCabe Memo—*i.e.*, affected sources should utilize "sustainably-derived agricultural- and forest-derived feedstocks"—is not a legally adequate proxy for BSER.

iii. EPA should include new NGCC units in building block 3 to the extent that they are now under construction, have been publicly announced or needed to replace coal-fired power plants shuttered as of state CPP plan submission.

EPA seeks comment on the opportunity to reduce CO_2 emissions at affected units by means of the addition, and greater operation, of new NGCC units. The agency also asks whether new NGCC units should be included as part of the BSER determination, and how to define state-

[311] FAO, Annex 6: Definitions and Basic Principles of Sustainable Forest Management in Relation to Criteria and Indicators (http://www.fao.org/docrep/003/x6896e/x6896e0e.htm).

[312] *Utility Air Regulatory Group v. EPA*, 134 S.Ct. 2427, 2449 (June 23, 2014).

level goals based on consideration of new NGCC deployment.[313] EPA finds this strategy is "clearly feasible," noting that its compliance modeling strongly suggests that the construction and operation of new NGCC capacity will be undertaken as a matter of fact as a CO_2 control method – in response to the CPP's requirements.[314] EPA, however, proposed not to include new NGCCs in the BSER and state goal calculation analysis because it assumes that the additional demand for natural gas would result in higher natural gas prices, and new NGCC units would entail higher capital investment costs, and pipeline infrastructure costs.[315]

In its October 29, 2014 NODA, the Agency noted it previously had acknowledged that replacing fossil steam generation with new NGCC units and natural gas co-firing at existing fossil steam units may be considered the BSER for various reasons.[316] EPA found that new NGCC units and natural gas co-firing at existing fossil steam units may be considered part of a "system of emission reduction," in light of the broad definition of that phrase; for example, the affected sources can themselves undertake those actions (i.e., fossil steam generators may invest in new NGCC units and coal-fired steam generators may co-fire with natural gas); and steam generators may reduce their utilization, which, through the operation of the market, would lead to the construction of new NGCC capacity.[317] In addition, EPA found that replacing fossil steam generation with new NGCC units is "adequately demonstrated" in light of the extent to which this has already occurred. In its October 28, 2014 Notice of Data Availability, EPA refreshed its request for comment on adding new NGCC to the BSER determination and the state goal calculation.[318]

EPA also requested comment on a formulation by which new NGCC capacity would not become part of the goal computation for all states, but rather only for those states with little or no potential for natural gas redispatch from existing NGCC units. In this way, overall costs could be constrained while the stringency of those state targets could be increased and disparities mitigated between states that received relatively more stringent targets due to their greater existing NGCC redispatch potential and those with less potential.[319]

1. The use of new NGCC units to displace coal generation and reduce emissions is "adequately demonstrated" by recent electric sector experience and forecast system response to the market and regulatory environment.

---

[313] 79 Fed. Reg. 34876-77.

[314] *Id*. at 34,876.

[315] *Id.* at 34,876-77.

[316] 79 Fed. Reg. 64,550.

[317] 79 Fed. Reg. 64550; 79 Fed. Reg. 34,885-90.

[318] 79 Fed. Reg. 64,550.

[319] 79 Fed. Reg. at 65,549.

CATF supports application of new NGCC redispatch as part of the BSER determination and state goal calculation process (to the extent that they are now under construction, have been publicly announced or needed to replace coal-fired power plants shuttered as of state CPP plan submission), and the explicit inclusion of new NGCC on the compliance side through a mass-based allowance trading system.

EPA's assertion that replacing fossil steam generation with new natural gas combined cycle units is "adequately demonstrated" is well-supported. Prior to 2008, electricity produced by coal-fired power plants supplied nearly half of the electricity produced in the U.S. while natural gas-fired generation supplied only 21 percent.[320] Since 2008, the percentage of electricity produced by coal has declined while natural gas generation has risen. This trend has been driven by two factors: (1) the rapid addition of combined cycle natural gas units to the power supply since the year 2000; and (2) the availability of cheaper natural gas. Figure 23 below illustrates the large amount of added natural gas capacity since the year 2000.

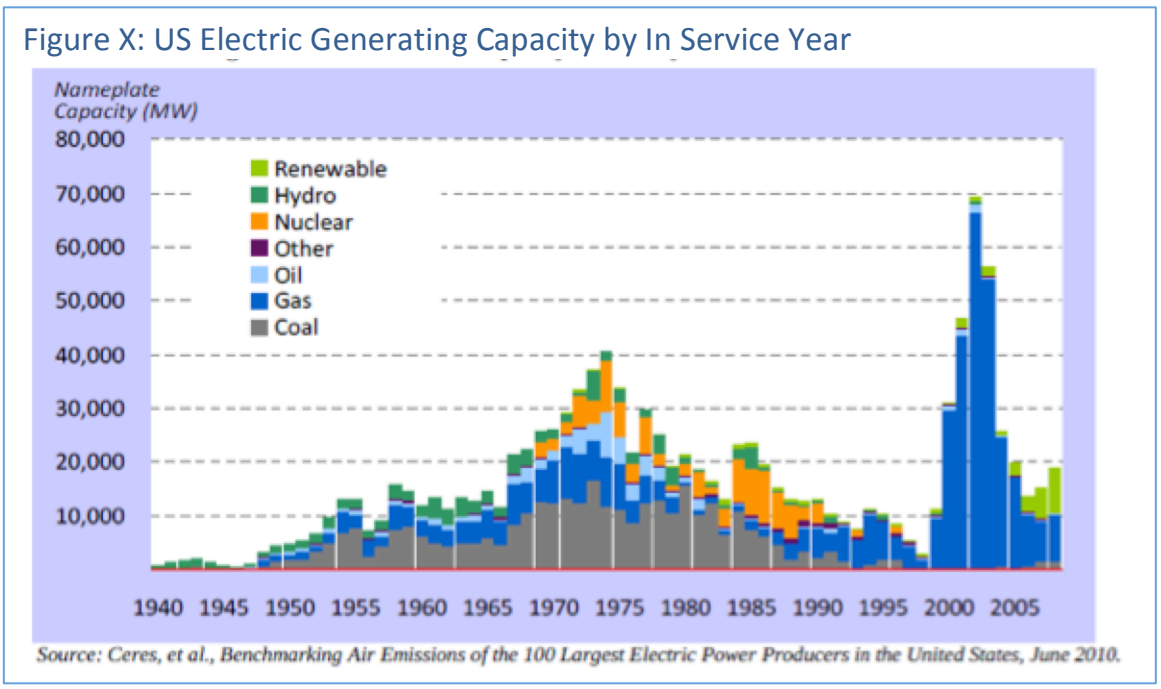


Figure 23: Ceres, Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States (June 2010), available at: http://www.nrdc.org/air/pollution/benchmarking/files/benchmarking-2012.pdf.

This increased NGCC generation has largely come from the fleet of new, more efficient combined cycle natural gas units that came online during this period. The EIA data below shows that increased natural gas unit generation has displaced coal unit generation. See Figure 24 below:

[320] US Energy Information Administration, *Short Term Energy Outlook.* http://www.eia.gov/forecasts/steo/report/electricity.cfm.

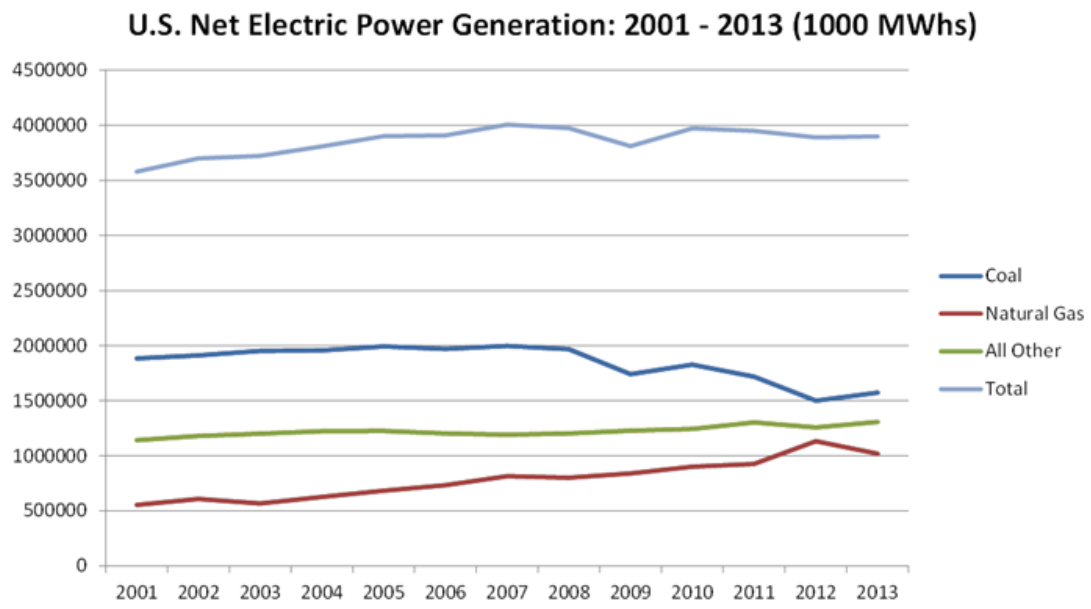


Figure 24: (Source U.S. EIA)

As a result of these factors, since 2008, CO_2 pollution from the power sector has fallen sharply.[321]

EPA's IPM compliance modeling also shows that NGCC units constructed after 2012 come online and run, displacing existing coal generation and resulting in reduced carbon dioxide emissions.[322] Likewise, the NorthBridge modeling of CATF's Power Switch proposal, discussed *supra* Sec. III.b.i, predicts that new NGCC units will replace coal capacity retirements resulting from the combination of lower natural gas prices and existing EPA regulations (for example, the Mercury and Air Toxics Standards ("MATS") rule), as well as those retirements predicted to occur for compliance with the CPP. The NorthBridge analysis found that these new NGCC units come online to replace the lost coal generation, lowering overall electric system emissions. In the years immediately prior to their retirement, those coal units ran at utilization rates less than 50 percent annually. And the least economically viable coal units are the most vulnerable to retirement. Therefore, new NGCC units coming online to replace this coal capacity have substantial "headroom" to reach higher utilization rates and displace the generation from existing coal units that are not predicted to retire. This incremental gas redispatch effect from the new NGCCs presents the opportunity for additional, cost-effective carbon dioxide reductions from affected coal units.

---

[321] U.S Energy Information Administration, "U.S. Energy-Related Carbon Dioxide Emissions, 2013" October 2014: See: http://www.eia.gov/environment/emissions/carbon/pdf/2013_co2analysis.pdf.

[322] In fact, in some ways EPA's use of the terms "new" and "existing" NGCCs represents a false distinction. Recent power system experience and future forecast analyses suggest that when new NGCCs come online, they run, displacing coal generation and reducing emissions. This is because the newest NGCCs are also generally the most efficient. Omitting the potential carbon dioxide reductions from new NGCCs would ignore this recent experience and predicted future response of the electric system to market and regulatory conditions.

Going forward, particularly in markets where coal units would otherwise run on the margin, new NGCC units that come online will have the same displacement effect. Thus, the use of new NGCC units to displace existing coal generation and provide coal unit carbon dioxide emissions is clearly "adequately demonstrated" as a CO_2 reduction strategy and EPA has a reasonable basis to include it in determining the best system of emissions reductions and, in the state goal calculation, as a cost-effective mechanism to reduce CO_2 emissions. States should therefore evaluate (in their state goals) the emission reductions predicted due to under construction and publicly announced new NGCC as of the date when they submit its CPP plans.

2. EPA should include new NGCCs in the state goal calculation methodology to the extent that these units are under construction, have been publicly announced, or are needed to replace retiring coal capacity.

CATF recommends that, at a minimum, EPA should direct states to include in its state goal calculation the new NGCC capacity that is under construction or that has been publicly announced at the time state files their compliance plans. In addition, CATF recommends that EPA include in building block 3 all the new NGCC capacity needed to replace the coal unit retirements that have been publicly announced as of the date of the final rule.

Unfortunately, EPA has failed to provide quantitative support for its decision to exclude new NGCCs from the BSER determination and state goal calculation methodology. EPA simply assumes that the additional demand for natural gas would result in higher natural gas prices and that new NGCC units would entail higher capital investment, and pipeline infrastructure costs.[323] However, a thorough review of the CPP proposal, GHG Abatement Options TSD, and draft Regulatory Impact Analysis did not reveal EPA's quantitative basis for these conclusions. The only mention of new NGCC costs we could find in the documents supporting the CPP proposal is the following statement:

> For example, EPA analysis indicates that replacing the coal steam plant discussed above with a new NGCC facility would reduce the net CO_2 emission rate of the generating capacity by 62% at a cost of about $50/tonne of avoided CO_2 under the base case projected gas price and about $81/tonne of avoided CO_2 at a future gas price 50% higher than the base case projection. See preamble section VI.C.3.c.[324]

But, in fact, we could not find any discussion of new NGCC economics at "preamble section VI.C.3.c," nor could we find support for these numbers anywhere else in the Preamble or in the Agency's technical support documents. While the GHG Abatement Measures TSD devotes an entire chapter (Chapter 6) to an analysis of gas co-firing, no similar analysis exists for new NGCCs. Without more, EPA cannot reasonably reject new NGCCs as part of the BSER and the state goal calculation.

---

[323] 79 Fed. Reg. 34,876-77.

[324] *GHG Abatement Measures TSD*, 6-9.

If EPA is concerned about the use of new NGCCs putting additional upward pressure on natural gas prices or higher infrastructure costs, it need look only to its own IPM modeling to see that new NGCCs are predicted to be part of state compliance with the CPP without causing undue gas price or infrastructure cost impacts. In addition, the NorthBridge analysis of CATF's Power Switch idea also shows new NGCC capacity coming online to replace coal units that retire as a result of the CPP, finding that this will occur (including associated capital and gas pipeline infrastructure costs) without any significant increase in gas prices or other economic impacts, and at a marginal cost of compliance far lower than the Social Cost of Carbon. *See supra* Sec. III.b. In fact, all of the new NGCC units that have been announced or that the modeling analyses predict will be built after 2012 are "new" the day the come online. So, EPA's own analysis of the building block 2 gas redispatch strategy itself provides support for more explicitly including new NGCCs in the state goal calculation.

EPA simply has not provided quantified analytical support for its decision not to include new NGCCs in the BSER determination and state goal calculation methodology. If, after undertaking this analysis, EPA continues to have concerns about the gas price, capital and infrastructure cost impacts of broad inclusion of new NGCCs, EPA could direct states in their target setting to include new NGCCs only in the states has little or no potential for natural gas redispatch from existing NGCC units. In this way, overall costs and pressure on gas prices could be mitigated while the stringency of those state targets could be increased and disparities mitigated between states that received relatively more stringent targets due to their greater existing NGCC redispatch potential and those with less potential.[325]

3. Including new NGCCs in building block 3 is important in preserving the environmental efficacy of the CPP, as it properly accounts for their emissions, keeping new NGCCs from weakening the effective CPP state goals.

Including the potential for development and use of new NGCC units in building block 3 will ensure that the effectiveness of the EPA's proposal is not diluted by the construction of new NGCC units. The proposal contemplates the use of new NGCC plants as a compliance strategy but does not quantify the result because new NGCC are not included in the goal calculation methodology. To maintain the environmental efficacy of the rule, EPA must direct states to account for the CO_2 emissions of new NGCC units as part of state compliance demonstrations whether under mass-based or rate-based system.

Without this adjustment to building block 3, the CPP may create perverse incentives to build unnecessary new NGCC units. Because new units are not now subject to the CPP, a state could achieve emission reductions from affected sources by reducing corresponding generation and constructing new plants to serve the remaining load without counting the emissions from the new NGCC units.[326] Such an approach may reduce the emissions intensity of affected sources in

[325] 79 Fed. Reg. 64,550.

[326] Simply including new NGCCs in the state goal calculation methodology alone may not be sufficient to mitigate this perverse effect if states opt to comply through a mass-based budget limited to existing fossil units only. Such a structure would also create perverse incentives to build new NGCC units (which would not be under the state

a state without any overall reduction in fleet-wide emissions. Under the current proposal, emissions may simply shift from existing sources to new sources without any overall environmental benefit, a particularly troubling outcome as new NGCC units can remain in operation for a half-century or more.

IV. A mass-based allowance trading system provides the most effective, efficient, and affordable approach to implementing EPA's state goals for this industry

a. Section 111(d) provides states with flexibility in the choice of implementation approaches to achieve the state goals set by EPA.

As discussed *supra*, at Sec. II.a, the Clean Air Act is designed to control air pollution in the United States by means of a federal-state partnership. The essence of this partnership as reflected in both sections 110 and 111(d) is that EPA sets the environmental goals to be met, and the states must then submit to EPA for review and approval implementation plans that will achieve those federal goals. A state has "significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements."[327] Furthermore, in this case, given that the effects of the regulated pollutant—CO_2—are not localized, states should be allowed to act together to meet the federal goals on a combined interstate basis.[328]

b. EPA should provide incentives for states to adopt a mass-based form of the CPP state goals.

In accordance with section 111(d), EPA's proposed CPP provides states with a significant amount of flexibility in creating plans to implement the state emission goals set by EPA. One of the most significant aspects of this flexibility is that states have a choice of basing their required emission goal on an emission rate or a mass-based allowance system. This is consistent with EPA's section 111(d) regulations, which expressly authorize each approach.[329]

Regrettably, the CPP proposed by the Agency favors state adoption of rate-based goals, because EPA set the standard presumptively in the form of an emission rate, providing only specific rate-based goals for each state, but no mass-based goals. The CPP does allow states to translate the emission rate-based goal to a mass-based goal, provided that it is "equivalent." However, while a state will know the precise rate-based goal it must meet in advance of submitting its implementation plan, it will not know the precise mass-based goal, since it cannot

---

budget) rather than utilize existing NGCC units (that would) by placing a regulatory "price" on existing NGCC units when none would exist for new NGCC units.

[327] 79 Fed. Reg. at 34,891.

[328] Such interstate cooperation is not prohibited by the Compact Clause of the United States Constitution. U.S. CONST. art. I, § 10, cl. 3. See discussion, *supra*, at Sec. II.a.vii.

[329] 40 CFR § 60.21(f) provides in pertinent part: "Emission standard means a legally enforceable regulation setting forth an allowance rate of emissions into the atmosphere, [or] establishing an allowance system…." Likewise, 40 CFR § 60.24(b)(1) provides in pertinent part: "Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except where it is clearly impracticable."

know in advance whether its "translation" from the known rate-based goal to a mass-based goal will be approved by EPA. Therefore, even though a state may prefer a mass-based goal, it nevertheless may be led by administrative convenience combined with resource constraints to settle for a rate-based approach.

This is unfortunate, because a mass-based approach has many advantages over a rate-based one. CATF urges EPA to provide meaningful incentives to states to choose a mass-based approach—more specifically, by facilitating a mass-based system with an emissions cap involving the interstate trading of emission allowances. The proposed CPP does not do this, but EPA has sought comment on it, and EPA should in the final rule by provide a presumptive mass-based emission goal for each state and permit states to implement such goals by means of a CO_2 allowance trading program.

More specifically, CATF recommends that EPA should include the following in the final rule. These are described in more detail in Sec. IV.d *infra*:

- ***EPA should reverse the priority of rate-based and mass-based approaches in the final rule***. EPA should issue each state a presumptive mass-based CO_2 annual emission goal, but permit the state to adjust it or translate it into a rate-based goal; and

- ***EPA should offer states a model system for the trading of mass-based allowances***, including state specific caps, by means of comprehensive standard provisions that could be voluntarily adopted by states with a mass-based goal; ***or at a bare minimum, provide substantial guidance to states on the design and implementation of mass-based allowance systems with a cap***. EPA's model system could be a regional allowance system with identical plan provisions from participating states (or even a single multistate plan), or smaller allowance trading systems between several states without completely identical plans.

c. Advantages of a mass-based approach over a rate-based approach to implementation.

As EPA itself has recognized, mass-based systems have one key advantage in terms of environmental performance over rate-based systems—achievement of the target emissions level is much more predictable and likely in a mass-based allowance system with a cap. And from an environmental and climate standpoint, it is the overall level of CO_2 emissions that matters. EPA was faced with much the same issue in the 1998 NOx SIP Call,[330] and there decided to create a model mass-based trading program with a cap (more on this in Sec. IV.d, *infra).* EPA stated, in response to commenters arguing for a rate-based program:

> EPA recommends a cap-and-trade program for purposes of the NOx SIP call because, by limiting total NOx emissions to the level determined to address the

[330] EPA, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule, 63 Fed. Reg. 57356 (October 27, 1998).

> interstate transport problem, a cap better ensures achievement and maintenance of the environmental goal articulated in the NOx SIP call. In contrast, under a non-cap trading program, the addition of new sources to the regulated sector or increased utilization of existing sources could increase total emissions above the level determined to address transport, even though a NOx rate limit is met. [331]

This is equally true for this rule. EPA proposes to evaluate state plans implementing the CPP against four general criteria, roughly summarized as requiring enforceable, quantifiable and verifiable emission reduction measures that will meet the state goal and be reported to EPA.[332] A mass-based goal implemented by means of an allowance trading system – particularly if EPA determines to include new fossil fuel fired EGUs in the final BSER, and allow them to be used as a state compliance measure – will meet these criteria more effectively than an emission rate approach.[333]

Other advantages of a mass-based allowance system over a rate-based system include greater simplicity, ease of compliance and administration; ease of enforceability, greater transparency; the advantage of experience, and consistency with present and future carbon policies. Each of these advantages is explored below.

i. Greater simplicity, along with greater ease of compliance and administration.

EPA's proposed regulation of existing fossil-fueled power plant carbon emissions is a huge undertaking, affecting all 50 states and one of the largest industries in the country, and in order to succeed, must be as simple as possible.[334] A mass-based system with a cap on fossil-fueled power plant emissions is inherently simple and straightforward, as all of the factors that can reduce those emissions are automatically accounted for. The rate-based approach that EPA has proposed in the CPP is much more complex.

---

[331] *Id.*; 63 Fed. Reg. at 57457-58.

[332] *See, e.g.,* 79 Fed. Reg. 34,830 at 34,838 ("The EPA is proposing to evaluate and approve state plans based on four general criteria: (1) Enforceable measures that reduce EGU CO_2 emissions; (2) projected achievement of emission performance equivalent to the goals established by EPA, on a timeline equivalent to that in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary.").

[333] One potential drawback of allowance trading systems over broad geographic regions is that they do not ensure similar emission reductions throughout the affected region. This is because some sources may choose to use allowances to emit above the required emission level, while other sources emit below the level. This creates the potential for certain areas to experience no decrease, or even an increase, in emissions. While this potential for emission "hot spots" is a problem in the context of criteria pollutants or air toxics that have localized health and ecosystem impacts, it is not a problem in the context of the CPP, because CO_2 impacts are not localized.

[334] William F. Pedersen, *Should EPA Use Emissions Averaging or Cap and Trade to Implement §111(d) of the Clean Air Act*?, 43 ELR 10731 (Sept. 2013).

One of the main sources of the complexity of the rate-based approach embodied in the CPP is that states that wish to take advantage of the impacts of energy efficiency and renewable energy programs on fossil plant emissions must separately *estimate* those impacts, because those programs do not affect the rate of emissions from a fossil plant in any consistent manner. At best, this is an extremely difficult task that to date has achieved only mixed success. Furthermore, different states may adopt different approaches to such estimates, producing inconsistent results among the various states; even more problematic is the obvious temptation that states will have to skew their estimates to the high side, thereby reducing the actual emission reductions otherwise obtainable from the CPP,[335] as well as the possibility of "double counting" the reductions attributed to energy efficiency or renewable energy measures.[336]

Rate-base systems (involving some states) also create the potential for "seams conflicts" with mass-based systems (involving other states). This can allow states within a single RTO that are implementing these different types of systems to meet their emission goals, by shifting generation from the mass-based state to the rate-based state, rather than by reducing emissions.[337] Also, coal plants in a rate-based system that rely on heat-rate improvements could under certain conditions be dispatched before rather than after lower emitting natural gas combined cycle units, thereby increasing net fossil emissions.[338]

It is noteworthy that many states and other stakeholders have requested that EPA use a mass-based allowance approach to the CPP, and in so doing have often stressed the importance of simplicity.[339]

---

[335] *Id. See also,* Arik Levinson, Georgetown University, Comment on the new Clean Power Plan, Doc. ID: EPA-HQ-OAR-2013-0602-14447 (Aug. 9, 2014).

[336] *See, e.g.,* Regional Greenhouse Gas Initiative (RGGI) States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationery Sources: Electric Utility Generating Units, Doc ID: EPA-HQ-OAR-2013-0602-22395 (Nov. 5, 2014), at pp. 10-11.

[337] For example, assume a state with a rate-based system with a single blended emission rate applied to both coal and gas units and a nearby mass-based state in the same or interconnected power markets. Further assume the gas units in the mass-based state are slightly more efficient than those in the rate-based state and historically have been dispatched before the gas units in the rate-based state. Yet under a blended rate standard, the less efficient gas units in the rate-based state could displace the more efficient units in the mass-based state because the production incentives in the rate-based state enable those gas units to lower their dispatch bids. With fewer emissions from the gas units in the mass-based state, the mass-based state achieves its mass-based emission budget. Further, the increased generation from the gas units in the rate-based state lowers the average fossil emission rate in that state allowing it to meets its blended emission rate standard. Further, looking at the two states together, overall emissions and production costs increase and the economic efficiency of the power system declines. This seams problem could also occur for rate-based standards applied to only coal units.

[338] *See, e.g.,* Bruce Phillips, Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions, (Feb. 27, 2014, The NorthBridge Group, prepared at the request of CATF), at pp. 10-11, *available at*: http://www.catf.us/resources/publications/files/NorthBridge_111d_Options.pdf.

[339] *See* Comment submitted Sept. 4, 2014 by T. Marks, Director of Arkansas Dept. Envt'l Quality, on behalf of Midcontinent States Environmental and Energy Regulators (Illinois, Arkansas, and Michigan), EPA-HQ-OAR-2013-0602-16078; Comment submitted Sept. 5, 2014 by R. Flynn, New Mexico Env't Dept., EPA-HQ-OAR-2013-0602-17291; Comment submitted Sept. 12, 2014 by D. Wyant, Michigan Dept. Envt'l Quality EPA-HQ-OAR-2013-

ii. Ease of enforceability.

A mass-based system with a cap on fossil-fueled power plant emissions is much more easily enforced. Complex modeling, projection, allocation and verification systems needed for a rate-based system, such as those described by EPA in the CPP proposal and support documentation,[340] will not be necessary for a mass-based system. Rather, power plant emissions can be simply measured and recorded by widely available continuous monitoring equipment.

iii. Greater transparency.

The simpler the system, the easier it will be for the industry, the states and the public to understand and ultimately accept; a complex system that only a few can understand will not meet with the same level of acceptance and support. For the reasons stated above, a mass-based system is simpler, and thus more transparent and ultimately will likely prove more acceptable.

iv. The value of experience.

In the NOx SIP Call, EPA noted that one important consideration for choosing a mass-based allowance system over an emission rate approach was the much greater amount of experience that EPA and states had in implementing mass-based allowance systems. As long ago as 1998, EPA noted, "the procedures for a cap-and-trade program have already been developed and used successfully, whereas procedures for other types of multi-state trading programs have not been developed to the same degree. Therefore, EPA does not have the same level of experience or established protocols to follow in the design and administration of other types of trading programs."[341] This disparity of experience has increased markedly since then, given EPA's and states' subsequent experience gained over the past decade in implementing the NOx SIP Call (2003 to 2008) as well as the Clean Air Interstate Rule[342] (2009 to 2014).

v. Consistency with present and future carbon policies.

0602-17284; Comment submitted Sept. 16, 2014 by J.L. Stine, Minnesota Pollution Control Agency, EPA-HQ-OAR-2013-0602-17900; Comment submitted Sept. 18, 2014 by B. Shelly, President Navajo Nation, EPA-HQ-OAR-2013-0602-21646; Comment submitted Dec. 13, 2013 by Environmental Agency leaders from California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, and New York, EPA-HQ-OAR-2013-0602-0198. —Comment submitted by RGGI States, EPA-HQ-OAR-2013-0602-22395.

[340] *State Plan CO_2 Performance TSD* 21-36.

[341] 63 Fed. Reg. 57,356, at 57,457.

[342] EPA, "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call; Final Rule," 70 Fed. Reg. 25182 (May 12, 2005). CAIR was also implemented by means of an allowance trading system.

A number of states have already taken the lead in addressing CO_2 emissions, and those states are implementing mass-based allowance systems, not emission rate systems.[343] Furthermore, the only Congressional effort to date that is limited to addressing power plant emissions is the Acid Rain Program, a mass-based allowance trading system under Title IV of the Clean Air Act.

Based on this experience, and the advantages of a mass-based system, including those previously described, it seems quite likely that any future national legislation comprehensively regulating greenhouse gases will take the form of a mass-based allowance system rather than a rate-based system. Thus, a final section 111(d) rule containing an emission standard in the form of a mass-based system would likely be much more easily integrated into any future economy-wide greenhouse gas legislation.[344]

d. EPA should provide states with incentives to adopt mass-based allowance trading systems with a cap.

i. EPA should finalize a rule that specifically establishes a mass-based goal for each state.

EPA should provide states presumptive mass-based goals, rather than the solely rate-based targets EPA has proposed. While EPA has included several illustrative examples of how a state might convert a rate-based goal into an equivalent mass-based one,[345] that approach is not sufficient to offer incentives to states to adopt a mass-based option, as the path of least resistance, other things being equal, will be for states to adopt the inferior rate-based approach.

In the final rule, EPA therefore should reverse the goal format priority proposed in the CPP by specifying presumptive state mass-based goals rather than rate-based ones. This will facilitate the adoption by states of mass-based goals, as translation from a rate-based goal will no longer be required. Of course, the final analysis and the final implementation choice will remain the state's, but encouraging states to adopt a mass-based approach will, for all of the reasons stated in Sec. IV.c., result in a stronger, and simpler CPP that will be more transparent and easer to comply with and enforce. In any event, at a bare minimum, EPA must include a presumptive mass-based emission goal in addition to a rate-based goal for each state in the final rule, in order to offer states at least an equal opportunity to choose the mass-based approach.

---

[343] The two main state efforts to date are the Regional Greenhouse Gas Initiative ("RGGI") and the California Global Warming Solutions Act program.

[344] According to the comments submitted in this docket by the RGGI States, "every serious proposal to reduce carbon emissions from EGUs, from proposed US legislation to programs in place in California and Europe, has identified allowance trading as the best approach." RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationery Sources: Electric Utility Generating Units, Doc ID: EPA-HQ-OAR-2013-0602-22395 (Nov. 5, 2014), at p.8.

[345] *State Plan CO_2 Performance TSD*, at 13–19; *Rate-Based to Mass-Based Translation TSD*.

ii. CATF's approach to the mass-based goal calculation.

CATF proposes a simple and transparent approach for calculating state mass goals that are consistent with EPA's reduced utilization approach to BSER and that builds on the Agency's goal data computation methodology ("GDC"). This methodology was developed for CATF by NorthBridge, and is more fully described in its whitepaper dated December 1, 2014.[346] As described in the whitepaper, based on data from EPA analyses contained in its Goal Data Computation TSD ("GDC") calculations and the June 2014 Regulatory Impact Analysis,

> the methodology estimates state-specific business-as-usual ("BAU") electric loads in 2030. It then determines the fuel-technology mix and energy efficiency resources needed to meet that load based on the data and the computational process in the GDC. Finally, it determines the carbon emissions associated with the fossil generating facilities covered under the rule using emission rates from the GDC.[347]

Specifically, under the CATF/Northbridge suggested approach, 2012 retail sales are grossed up to account for lines losses, reflecting total 2012 generation, to which a BAU load growth rate (between 2012 and 2030) is applied. This produces an estimate of total state generation needs for 2030. The 2012 retail sales assumptions in these calculations are taken from the GDC and the load growth data are taken from the EPA's Integrated Planning Model cases issued as part of its June 2014 Regulatory Impact Analysis. This approach to incorporating load growth factors in the goal development process is analogous to the EPA's approach taken in the NOx SIP call.

Next, demand and supply resources are deployed sequentially to meet total state generation needs. All four building blocks, along with generating resources not covered under the CPP, are represented in this analytical process; in this way, working back through the application of the building blocks, total resources are balanced with total energy demands, and the utilization of existing affected sources is reduced.

- First, the total BAU state generation needs in 2030 are reduced by the state's EE (building block 4) as specified in the GDC. This results in an estimate of the total amount of energy demand in each state to be met.

- Next, total net energy demand is reduced by qualifying renewable energy resources (building block 3) as specified in the GDC.[348]

---

[346] Bruce Phillips, "Translating Emission Rate Goals into Mass Goals under the Clean Power Plan," (Dec 1, 2014) [hereinafter "NorthBridge Whitepaper"] (Ex. 11).

[347] NorthBridge Whitepaper, at 2.

[348] The analysis here is just illustrative – we strongly encourage EPA to strengthen building blocks 1 and 3 as we have suggested *supra* Secs. III.a and III.c.

- Following that, a block of energy from generating sources whose emissions are not covered under the rule are deducted, i.e., nuclear, hydro-electric, uncovered fossil, and net interstate imports or exports.[349]

- The last remaining block of demand is met by covered fossil generation (coal steam, NGCC, oil/gas steam and other covered generating unit). Generation from NGCC capacity is deployed first up to a maximum capacity factor of 70 percent consistent with the EPA's GDC methodology. Any remaining energy needs are met from existing coal and oil/gas steam in proportion to the 2012 generation levels from these two sources. This process incorporates building block 2 by dispatching NGCC to its maximum potential before coal.

The foregoing state-specific calculations for 2030 are illustrated in Figure 25 below.

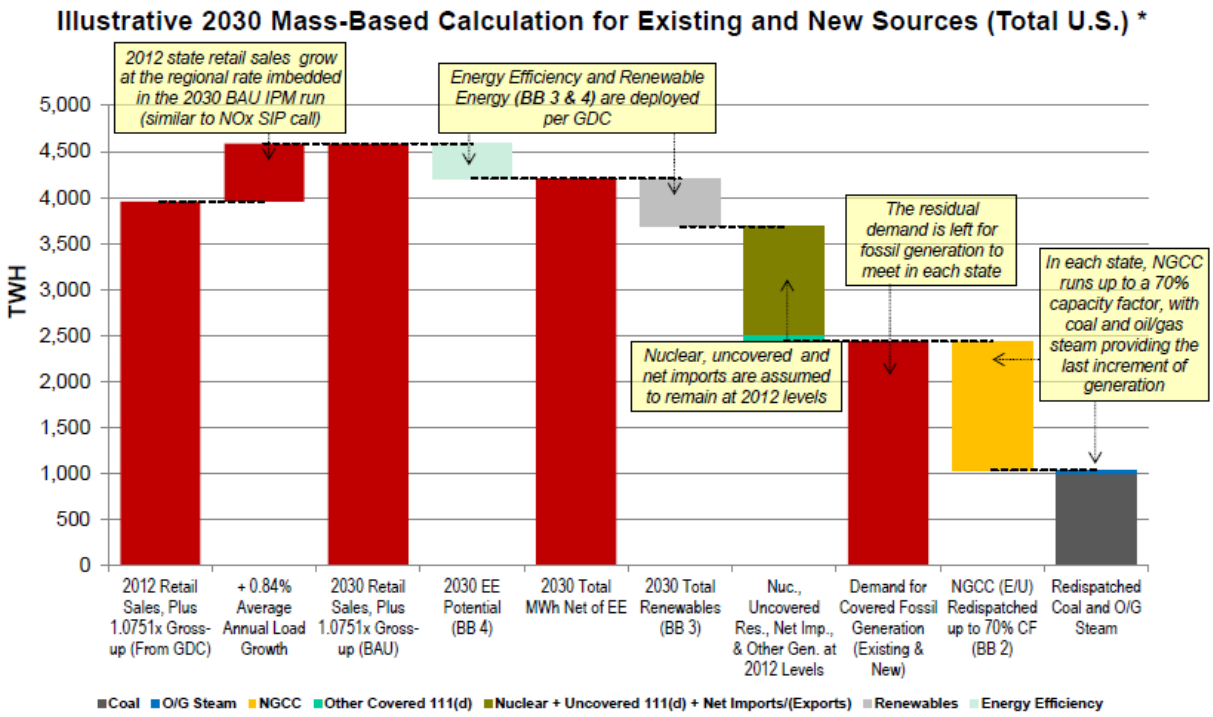


Figure 25 Bruce Phillips, "Translating Emission Rate Goals into Mass Goals under the Clean Power Plan," (Dec 1, 2014) (Ex. 11).

So far, this analytical process produces estimates of the energy mix required to satisfy electric demand in a future year. The results of this process in comparison to 2012 generation are shown below in Figure 26.

[349] The generation from all of these except new nuclear is assumed to remain constant over time. The amount of energy from these fixed resources is calculated from GDC data by deducting 2012 coal, NGCC, oil/gas steam, other covered generation, and existing renewable energy from total 2012 sales. For states with expected new nuclear generation, the amount of generation from these new sources is then added to this block of energy.

Finally, to create the state's emission budget, the amount of energy produced by each fossil source covered under the rule is multiplied by the average state emissions rate for that fossil source in 2012. The one exception to this process is the coal emission rate, which is assumed to be 6 percent lower than 2012 levels consistent with building block 1 of the GDC.[350]

This results in the estimated covered emissions shown in Figure 26 below. The total U.S. covered emission estimate of 1,543 million metric tons of CO_2 is a 21 percent reduction relative to 2012 levels.

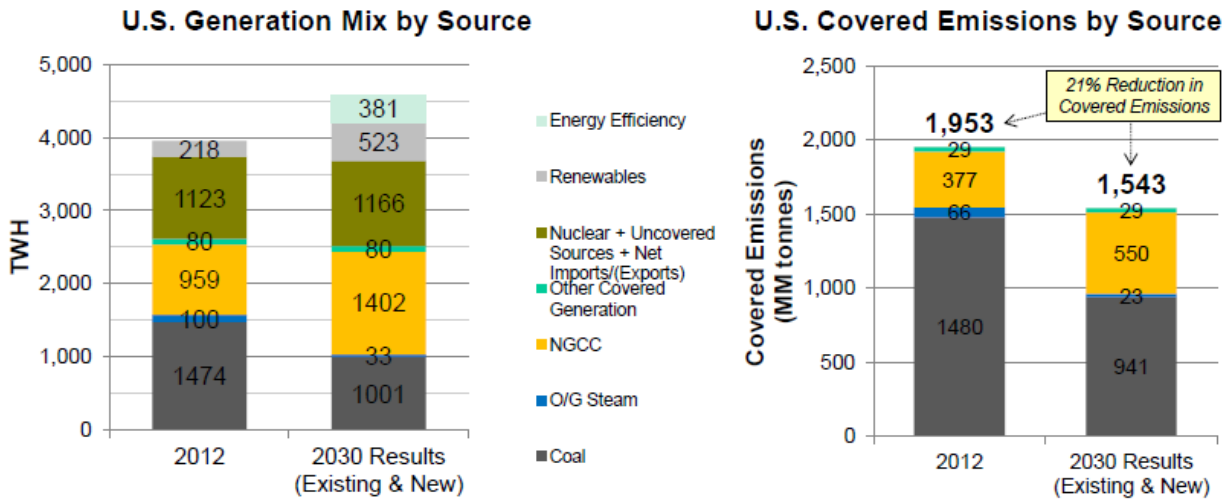


Figure 26

This methodology is a "first principles" approach to mass-based calculation. It starts with fundamental generation demand and resource data, along with the building block assumptions used by EPA in the GDC process, using them to determine the EPA's proposed emission rate goals. Because it is based on complete and balanced estimates of electric demand, energy efficiency and generation in future policy years, it is simple, intuitive, and fully transparent. And, because it relies on the same assumptions and calculation process used by the EPA, the resulting annual CO_2 mass goals are consistent with the EPA's definition of BSER and equivalent to the proposed rate goals.

iii. EPA should facilitate interstate trading of mass-based allowances that may be voluntarily included by states as part of their implementation plans.

Interstate trading of mass-based emission allowance furthers the benefits of mass-based CPP goals discussed above by creating additional compliance flexibility, providing a means of compliance when local factors constrain state action, and by allowing a state to comply in an economically efficient manner.

[350] Again, this is illustrative of the computation process only. CATF strongly recommends that EPA finalize a building block 1 rate reflecting all unit specific measures, as we describe *supra* at Sec. III.a.

CATF does not recommend that EPA attempt to facilitate interstate trading or averaging of rate-based emissions. As discussed above, EPA and the states have substantial experience in the design and operations of mass-based allowance trading systems. No such experience exists with rate-based systems. Furthermore, rate-based systems are more complex, and a patchwork of mass-based and rate-based systems around the country would prove extremely difficult to administer smoothly and effectively.[351]

EPA can structure voluntary incentives for emission allowance trading in a number of ways, including: (a) creating a complete mass-based trading system for voluntary adoption by states, similar to that employed in the NOx SIP Call; or (b) providing detailed guidance to states wishing to (1) create new regional mass-based allowance trading systems, or (2) join existing systems such as RGGI or the California Global Warming Solutions Act Program, or (3) trade allowances with other states that have non-identical (but mass-based) implementation plans.

iv. EPA can create a comprehensive CO_2 emission allowance trading program that States may voluntarily adopt, just as the Agency did in the NOx SIP Call.

The NOx allowance trading program established by EPA as part of the 1998 NOx SIP Call provides an excellent model for a trading rule under a finalized CPP. EPA explained that the purpose of the NOx trading program was "to provide a compliance mechanism that capitalizes on a proven means of cost effectively meeting a specific emissions budget that the Agency will assist States in administering."[352] State participation in the trading program was voluntary, but participating states that included the program in their SIPs enjoyed a significantly streamlined SIP approval process and sources involved in the program reaped substantial cost savings and increased compliance flexibility.[353]

The basic elements of the NOx SIP Call, which are equally appropriate for the CPP were as follows:

- EPA established state emission budgets for affected power plants by applying IPM growth factors and a target emission rate to base year heat input.
- EPA set a region wide emission cap equal to the sum of the state emission budgets;

[351] As EPA noted in the NOx SIP call in a related context, "it would not be administratively cost-efficient for EPA to manage multiple trading programs with a variety of applicability and other requirements designed to address the same issue." 63 Fed. Reg. 57,356, *supra*, at 57,461.
[352] 63 Fed. Reg. 57356, *supra*, at 57457.

[353] *See generally,* 63 Fed. Reg. 57356, supra, at 57456—47; EPA stated, at 63 Fed. Reg. 57458, that its "intent in issuing a model rule for the NOx Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving more than 90% of the required reductions…."

- Allowances were allocated to states in the amount of their emission trading budget, and states had broad discretion on how to allocate allowances from their trading budget to affected sources;[354]
- States could choose among a variety of options to reduce target emissions;
- At the end of each compliance period, each source was required to surrender sufficient allowances to cover its emissions;
- Sources with inadequate allowances had the following year's allocation automatically reduced by 3 times the amount of the deficiency;
- Sources with excess allowances could sell unused allowances;
- Sources with excess allowances could also bank them for use in a subsequent compliance period, subject to a "flow control" provision that limited use of banked allowance in a particular compliance period when the total bank exceeded 10% of the total regional budget for the following year;[355]
- Sources used continuous emission monitoring systems or other methods approved by EPA to monitor and report emissions;
- EPA administered the trading program for participating states, and those states shared responsibility by allocating allowances, inspecting and auditing sources and enforcing the program.[356]

EPA also included in the NOx SIP call a new source set-aside equal to 5 percent of a state's budget allocation.[357] EPA should include such a set-aside for new fossil EGUs in an CPP CO_2 budget-trading program, in an amount necessary to account for projected growth through 2030.[358] States participating in the program would be required to include emissions from new fossil-fired generation under the cap, and allowances to such units would be allocated only from the new-source set-aside; the overall state budget cap would not be increased. As long as allowances were allocated out of the new-source set-aside, states could chose how to allocate those allowances; for example, allowances could be auctioned to new units, based on the appropriate new source emission standard established under section 111(b) or some other method. Unused allowances in the set-aside could be returned each year to the state's general allowance pool for existing units or retired, in whole or in part.

States participating in the NOx budget program were also permitted to award allowances for early emission reductions (at least 20 percent below baseline), to be used during the first two

---

[354] "Affected sources" in the context of the CPP CO_2 budget trading program would be limited to fossil-fuel-fired power plants, and allowances would only be allocated to such units.

[355] A flow control mechanism for banked allowances may not be needed in the CPP, as the impacts of CO_2 are not only spatially diffuse, but temporally diffuse as well.

[356] *Id. See also*, EPA, "A comprehensive overview and background of the NOx Budget Trading Program and ozone," at p.6, available at: http://www.epa.gov/airmarkets/progsregs/nox/docs/NBPbasicinfo.pdf.

[357] 63 Fed. Reg. 57356, *supra*, at 57370-71.

[358] A new-source set-aside would not need to be created if EPA includes the emissions impact of new fossil sources in its promulgation of state goals, as discussed *supra*, at Sec. III.c.iii.

years of the program and then retired.[359] EPA could allow states participating in the CO_2 budget trading program the option of awarding additional allowances for early reductions, that is, emission reduction of at least 20 percent below baseline that were accomplished between the submission date for the state's section 111(d) plan and 2020, for use in meeting the interim goals until 2030; such allowances would be retired no later than 2030 and would be limited in amount to 5% of a state's total allocation.[360]

The CO_2 budget-trading program should also address unit retirements. Retirement of existing high-emitting units can be a substantial source of overall system emission reductions, but that benefit can be compromised if retiring units are permitted to retain their original allowance allocation indefinitely. On the other hand, requiring allowances to be immediately retired upon unit retirement could provide a disincentive for those units to retire in a timely fashion. A balanced approach is needed. CATF thinks that a reasonable approach would allow states participating in the allowance trading program to permit units that retire (or announce retirement) following the submission date for the state's 111(d) plan[361] and retire before 2030 to retain their allowances until 2030, and those that retire during or after 2030 would not retain any allowances post-retirement. Thus, allowances from units retiring prior to 2030 would be permanently retired in 2030, and allowances from units retiring during or after 2030 would be retired effective on the unit's retirement date. This would provide units with an incentive to retire prior to 2030, but would take full environmental advantage of those retirements starting in 2030.

EPA must not permit states participating the model CO_2 budget trading program to allow emission reductions, estimated or otherwise, from sources outside of the regulated sector to be used by regulated sources to "offset" their emission requirements. Because emission reduction offsets do not reduce power plant emissions, and in fact may serve to increase them (via an offset mechanism), they must not be permitted under section 111(d).

Also, because a model CO_2 budget trading program would require regulated power plants to be responsible for holding sufficient allowances to cover their emissions, states participating in the program could not utilize the "portfolio approach" described by EPA in the CPP proposal; among other things, distributing (and effectively diluting) the legal obligation to hold allowances among entities other than power plants would greatly complicate the administration and enforcement of the budget trading program.

---

[359] 63 Fed. Reg. 57356, *supra*, at 57474-75.

[360] In the NOx SIP call, EPA effectively limited the total amount of a state's early reduction credits to roughly 6% of the total program allowances by requiring that such credits be issued only from an allowance "compliance supplement pool." *Id.*

See also, EPA, "Interstate Ozone Transport: Response to Court Decisions on the NOx SIP Call, NOx SIP Call Technical Amendments, and Section 126 Rules; Final Rule," 69 Fed. Reg. 21603, 21628-29, 21643 (April 21, 2004).

[361] Units that retired or announced retirement prior to submission date for the state's 111(d) plan would not be included in the setting or implementing of state emission goals, and thus would not be allocated any allowances under a mass-based system.

v. EPA should, at a minimum, provide guidance to states wishing to implement mass-based allowance trading programs.

EPA alternatively can provide further guidance to states wishing to implement mass-based allowance trading programs. Although an interstate CO_2 budget trading program would most effectively be implemented by means of a comprehensive and complete allowance trading rule similar to the NOx SIP Call allowance budget rule, EPA could also provide more limited guidance to states desiring to participate in a mass-based national or regional allowance trading program. Several approaches could be useful in this context.

First, EPA could permit states to build on existing mass-based allowance programs such as RGGI and the California Global Warming Solutions Act program. Of course, such programs would need modification in certain respects to make them consistent with section 111(d) requirements and to ensure that they would produce emission reductions equivalent to the aggregate mass-based section 111(d) goals for the participating states. For example, offsets permitted under RGGI would not be allowed to effect compliance under the CPP, and neither would emission reductions from outside the regulated sector permitted under the California program.

Second, EPA could provide detailed guidance to states wishing to act collectively to create their own regional CO_2 budget trading program trading system. EPA's guidance would fall short of a complete and comprehensive rule, but would contain sufficient detail to ensure the integrity and credibility of a system that would meet the section 111(d) state goals in the aggregate for the participating states. The provisions of such a regional trading program would apply equally to all participating states, and would of course be subject to EPA approval.

Finally, several states could establish a trading system without necessarily having to adopt identical trading plan provisions. This option might appeal to states wishing to take advantage of mass-based allowance trading while avoiding the necessity of agreeing on all aspects of a single trading program. EPA would need in this case to ensure that the trading program provisions of each participating were compatible, capable of practical implementation, did not compromise the integrity of the section 111(d) requirements, and would meet the CPP state targets in the aggregate for all of the participating states. EPA's guidance should specify certain minimum criteria to ensure compatibility between states' programs e.g., rules for banking, borrowing, and a comparable price cap. EPA's guidance, should, at a minimum, confirm that such trading programs must include a cap on total emissions, are "self-correcting" within the meaning of the proposed CPP,[362] are permitted to be structured around a single interim compliance period (2020—2029), and allow for banking within this period (subject to the program's allowance allocation processes).

[362] "Self correcting" plans are those that "inherently would assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs." 79 Fed. Reg. 34,830, at 34,906-07.

e. EPA must finalize a commitment to periodically review and adjust the CPP State Goals.

Section 111(d) does not contain an explicit requirement for periodic review of the existing source performance standards – however, the purpose of the statute, its relationship to section 111(b) which does require review every eight years,[363] along with its reference to a section 110 procedure, and longstanding EPA interpretations requiring periodic review, give the Agency ample authority to finalize a commitment for periodic of the CPP.

For new sources, the Administrator must "at least every 8 years, review and, if appropriate, revise the [performance standards]."[364] In the CPP proposal, EPA recognizes that this "requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly."[365] This same principle applies to the CPP. All of "section 111 was intended to assure the use of available technology and to stimulate the development of new technology."[366] In order to be consistent with the track of the new source standards, and continue to promote new technology for pollution control on sources as they age, the CPP similarly must be periodically updated. There is support for this idea in section 111(d), which requires the EPA to "prescribe regulations, which shall establish a procedure similar to that provided in [section 110] under which each State shall submit to the Administrator a plan…."[367] This includes a cross reference to the requirement to revise state plans "from time to time as may be necessary to take account of revisions of such national primary or secondary ambient air quality standard or the availability of improved or more expeditious methods of attaining such standard."[368] While CO_2 is not a criteria pollutant, the language in CAA section 111(d) requiring a "procedure similar to that provided by section [110]" may be read to extend to all section 110 review requirements as well. Therefore, state CPP plans must also be subject to review when section 111(b) standards are updated and incorporated in state SIPs.

This is consistent with EPA's longstanding regulatory framework. The general 111(d) regulations require that, when corresponding new source standard of performance is proposed an emission guideline must also be proposed. The 1975 preamble also states EPA's expectation that there will be subsequent plans submitted after the initial emissions guidelines are set.

> [40 C.F.R.] § 60.22 … require[s] proposal… of an emission guideline after promulgation of the corresponding standard of performance… [B]y proposing (or publishing) an emission guideline after promulgation of the corresponding

[363] 42 U.S.C. § 7411(b)(1)(B).

[364] *Id.*

[365] 79 Fed. Reg. at 34,908.

[366] *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981).

[367] 42 U.S.C. § 7411(d).

[368] 42 U.S.C. § 7410(a)(2)(H).

> standard of performance, the Agency can benefit from the comments on the standard of performance in developing the emission guideline. … Extensive control strategies are not required, and after the first plan is submitted, *subsequent plans* will mainly consist of adopted emission standards.[369]

EPA should affirm this view in the final CPP.

EPA has previously concluded that the periodic review associated with some NSPS is also applicable to an existing source performance standard promulgated under section 129. Existing solid waste combustion units are regulated under CAA section 111(d) with emissions limits based on CAA section 112 and must comply with all CAA section 129(a) requirements. Section 129 does include an explicit five-year periodic review requirement for new sources, but not for existing sources.[370] However, when EPA finalized emissions guidelines for existing municipal waste combustors in 1991 under CAA sections 111(d) and 129, the Agency committed to review the standard

> 4 years[371] from the date of promulgation as required by the CAA. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.[372]

The procedural reference to CAA section 110 and the regulations for adoption and submittal of state plans for existing sources provide EPA with ample authority to require periodic review of the CPP. Further, EPA has a history of including the CAA section 111(b) periodic review requirement when setting CAA section 111(d) emissions guidelines Because the CAA is silent regarding the periodic review of CAA section 111(d) standards, "the question…is whether the agency's answer is based on a permissible construction of the statute."[373] An agency's interpretation is reasonable if it is not only a logical construction of the specific provision but

---

[369] 40 Fed. Reg. 53,340, 53,345 (Nov. 17, 1975) (emphasis added).

[370] *Compare* 42 U.S.C. § 7429 (a)(5) (requiring review of new source standards every 5 years) *with* 42 U.S.C. § 7429(b) (no such explicit requirement).

[371] Because the CAA section 111 standards were originally promulgated decades ago, it is important to note that CAA section 111(b) was originally written to allow review of NSPS from "time to time." On August 7, 1977 "time to time" was substituted with "shall, at least every four years review…" 1977. Act Aug. 7, 1977. And on November 15, 1990 "eight" was substituted for "four." Act Nov. 15, 1990.

[372] 56 Fed. Reg. 5,514, 5,515 (Feb. 11, 1991) (emphasis added), *withdrawn in part on other grounds and replaced by* Standards of Performance for New Stationary Sources and Emissions Guidelines for Existing Sources, 60 Fed. Reg. 65,387, 65413 (Dec. 19, 1995) (noting that the Act requires that the new source standards *and* the existing source guidelines must be reviewed not later than 5 years following initial promulgation and at 5-year intervals thereafter).

[373] *Chevron v. NRDC*, 467 U.S. 837, 843-44 (1984).

also gives effect to the statute as a whole.[374] The purpose of the section 111 is to apply the best system of emission reduction and "assure the use of available technology and to stimulate the development of new technology."[375] A periodic review of the CPP would ensure that CO_2 from existing power plants are controlled to the greatest degree practicable and would spur innovation in pollution control. We urge EPA to commit to a periodic review of these standards.

[374] *See Robinson v. Shell Oil Co.,* 519 U.S. 337, 341 (1997); *Ass'n of Tex. v. Timbers of Inwood Forest Assoc.,* 484 U.S. 365, 371 (1988) "Statutory construction is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme."

[375] *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981).