United States Environmental Protection Agency

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 34,830 (June 18, 2014).

EPA–HQ-OAR-2013-0602

COMMENTS OF THE NATIONAL MINING ASSOCIATION

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COMMENTS OF THE NATIONAL MINING ASSOCIATION

INTRODUCTION

The National Mining Association (NMA) submits these comments on the proposed regulations of the Environmental Protection Agency (EPA or Agency) under Section 111(d) of the Clean Air Act (CAA) to reduce carbon dioxide (CO_2) emissions from coal-based electric generating units (EGUs).[1] NMA also comments on EPA's Notice of Data Availability.[2]

NMA is a non-profit, incorporated national trade association whose members include the producers of most of America's coal, metals, and industrial and agricultural minerals; manufacturers of mining and mineral processing machinery, equipment, and supplies; and engineering and consulting firms that serve the mining industry. NMA's members produce and use electricity. NMA's mining and manufacturing company members are energy intensive. The cost of electricity is a substantial portion of their cost structure. NMA members also directly consume natural gas whose availability and price will be affected by the propose rule. The association's members also include owners and operators of EGUs that are subject to the proposal. NMA members supply coal to EGUs under fuel supply agreements that would be impaired by the proposed rule.

EPA's proposed regulations are unlawful at the most fundamental level. Put simply, the Administration has decided to bypass Congress in implementing far-reaching Executive Branch energy and environmental policy goals. Basic Separation of Powers principles and the dictates of the CAA, however, prohibit the Administration from doing so.

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1 "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule," 79 Fed. Reg. 34,830 (June 18, 2014).

2 "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice of Data Availability," 79 Fed. Reg. 64,543, 64,548 (Oct. 30, 2014).

The background of EPA's Section 111(d) proposal is well understood. Despite large legislative majorities in the first two years after the 2008 Presidential election, the Administration was unsuccessful in pushing through cap-and-trade legislation to significantly reduce power sector and other industrial and manufacturing CO_2 emissions, and the prospects for carbon legislation have declined ever since. Undeterred by Congress' flat rejection of the Administration's carbon agenda because of its extreme economic impacts, EPA set out, using (in the President's phrase) the "pen and the telephone," to "transform" (also the President's term) the power sector through executive fiat. One of Administrator Jackson's core goals for EPA upon taking office was not just to reduce air emissions but to create the new Administration's version of "a cleaner and more efficient power sector."[3]

The Agency's current Section 111(d) proposal is now the latest and by far the most "transformative" of its efforts to reengineer the electric power grid. Under EPA's proposal, states are assigned what EPA euphemistically calls "goals," but which in reality are binding federal mandates, to reconfigure both how power companies within the states produce electricity and to dictate how much electricity each state's citizens should be allowed to use. EPA has calculated what it considers to be the "best system" for each state to attain these mandates. Under EPA's "best" system, coal generation in general would decline dramatically and indeed would be zeroed out in 12 states.[4] To replace the lost coal generation, EPA makes a series of extravagant assumptions about the availability of replacement resources. Natural gas combined cycle generators would operate at a 70% capacity factor, even though only 10% operated at that

[3] *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 75 Fed. Reg. 45,210, 45,227 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.

[4] Alaska, Arizona, California, Connecticut, Maine, Massachusetts, Mississippi, Nevada, New Hampshire, New Jersey, Oregon, and Washington, as shown on the EPA spreadsheet at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents-spreadsheets.

level in 2012, a year of exceptionally low natural gas prices.[5] All "at risk" nuclear would keep operating without any defined plan as to how that is to happen, and all under-construction new nuclear would be presumed to come on-line on time despite the long history of delays in nuclear development.[6] Renewable generation would grow at unprecedented rates in many states, with East Central states presumed to increase renewable generation by 17% and southeastern states by 13% *each year*.[7] And in EPA's most heroic assumption, on a national-average basis, electric consumption would decline by 10% by 2030 as compared to a business-as-usual scenario[8]—requiring that consumption levels would be little higher than today and indeed would drop between 2020 and 2030[9]—even though the country will add more than 2 million people per year[10] and presumably the country may even regain robust levels of economic growth.

In seeking a vehicle to force states to implement EPA's reimagined electric system, EPA seized on Section 111(d), a provision that was adopted in the 1970 CAA and has been little-used since then (just to regulate four pollutants from five source categories out of the more than 70 source categories for which EPA has established new source standards[11]). Section 111(d) provides that, for certain pollutants emitted by certain source categories, EPA may adopt regulations that establish a "procedure" under which states develop plans containing state-established performance standards. Like new source performance standards under Section 111(b), Section 111(d) performance standards, for the more-than-four-decade history of the New

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5 79 Fed. Reg. at 34,863.

6 *Id.* at 34,870-71.

7 Greenhouse Gas Abatement Measures Technical Support Document (GHG Abatement Measures TSD) at 4-18, Table 4-5.

8 GHG Abatement Measures TSD at 5-46 – 5-47, Table 5-21.

9 *See* Data File: GHG Abatement Measures Scenarios 1 and 2 (3,773,750 GWh of consumption in 2014, rising to only 3,792,371 GWh in 2030). *See also* Energy Ventures Analysis, "EPA Clean Power Plan, Costs and Impacts on U.S. Energy Markets," August 2014.

10 Census Bureau, http://www.census.gov/population/projections/data/national/2012/summarytables.html.

11 Legal Memorandum for Proposed Carbon Pollution Emission Guideline for Existing Electric Utility Generating Units ("EPA Legal Memo") at 9.

Source Performance Standards (NSPS) program, have always been based on what has been called "best demonstrated technology," or BDT, for the regulated source category.[12] Under this consistent past practice, EPA has established ("listed") a source category and then performance standards have been set based on demonstrated and cost-justified technology (both physical technology and on-site practices) that individual facilities within the regulated source category can use to reduce the applicable emissions.

This past practice, however, was incapable of having the transformative effect on the power sector that EPA desired. With even EPA admitting that carbon capture and storage is not feasible at existing coal EGUs,[13] the only BDT that coal EGUs can use to reduce CO_2 emissions is efficiency improvements, and even under EPA's highly exaggerated view, coal EGUs can improve their efficiency, and hence reduce their CO_2 emissions, by only six percent.[14]

EPA thus decided to rewrite Section 111(d) as it wished Congress had written that provision, or, as EPA would have it, it has now offered a new "interpretation"[15] of that section. Under EPA's new "interpretation," the best "system" for reducing CO_2 emissions from coal-EGUs is to reengineer every state's electric utility system so as to force coal EGUs to operate less. Absolutely no precedent exists for this approach, and the approach would surely surprise the Congress that included the NSPS program in the 1970 CAA. Congress intended the NSPS program to foster economic growth by encouraging the construction of new industrial facilities that use affordable and demonstrated technology.[16] It never intended that the NSPS program would empower EPA to retard economic growth by forcing states to close existing facilities.[17]

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12 *See, e.g.,* Julie R. Domike and Alec C. Zacaroli, THE CLEAN AIR HANDBOOK, American Bar Association Section of Environment, Energy and Resources 2001, at 328 (3d ed. 2011) .
13 79 Fed. Reg. at 34,836.
14 79 Fed. Reg. at 34,861.
15 EPA Legal Memo at 33.
16 *See* discussion below at Comment III.C.
17 *Id.*

Indeed, in its effort to transform the power grid in this fashion, EPA has transformed itself from an environmental regulator into an energy regulator. As Federal Energy Regulatory Commission (FERC) Commissioner Phillip D. Moeller recently testified, "[i]f it isn't already obvious, the title of the proposed rule, the Clean Power Plan, makes it clear that *EPA is creating national electricity policy*."[18] The notion that Congress would have delegated authority to effectuate such far-reaching changes in how the power grid operates to EPA, an agency whose expertise is environmental not energy regulation, is dubious in the extreme. For instance, in formulating its "best" electric system in each state, EPA sets what it calls "best practices" renewable portfolio standards for each state.[19] Renewable portfolio standards (RPS) have long proved to be highly controversial. As EPA relates, the legislatures of 28 states have adopted RPS[20] (one of those states (Ohio) subsequently froze its RPS for two years[21]). Ohio aside, 22 state legislatures have decided *not* to adopt RPS. Congress nowhere delegated authority to EPA to instruct the elected representatives of 22 states—or most of the other states which adopted RPS that are far less ambitious than EPA's proposal—on the "best practices" for developing costly and only intermittently available renewable resources. Congress didn't even give FERC, the nation's electric regulator, that authority, much less EPA.

EPA has continued its past practice of pretending that its rules will have less impact than they will. For instance, EPA is at pains to say that the main body of the rule does not take effect

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18 Written Testimony of FERC Commissioner Philip D. Moeller Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives, Hearing on FERC Perspective: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges (Moeller E&C Testimony), July 29, 2014 (emphasis added), available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

19 79 Fed. Reg. at 34,866-67.

20 GHG Abatement Measures TSD at 4-11 – 4-13.

21 Columbus Business First, "The Freeze Is On – Kasich signs S.B. 310, Halts Renewable and Energy-Efficiency Standards," June 13, 2014, available at http://www.bizjournals.com/columbus/news/2014/06/13/the-freeze-is-on-kasich-signs-s-b-310-halts.html.

until 2030, with the rule taking effect only on an "interim" basis in 2020.[22] But EPA's own (under)estimates of the effect of the rule belies these efforts. According to EPA's Regulatory Impact Analysis (RIA), electric sector compliance costs in 2020 will be $7.4 billion, rising by only an additional $1.4 billion to $8.8 billion in 2030.[23] Coal generation (GWh) is reduced by 22% as compared with the base case scenario by 2020 and then only by another 5% for a total of 27% in 2025, which remains constant in 2030.[24] About 30-49 GW of all coal-fired capacity is projected to retire by 2020, and these estimates are incremental to the retirements that the MATS rule will cause.[25] Given that EPA does not even plan to approve state plans until 2017 at the earliest (by 2018 or 2019 if states elect the two- or three-year option to submit plans),[26] the impact of the rule will be real and immediate. And as shown in Section IX below, these impacts will be far greater than EPA's estimates.

EPA's rewriting of Section 111(d) to suit its own regulatory purposes is analogous to EPA's Tailoring Rule, where EPA, also in the guise of "interpretation," rewrote a statutory provision to suit its regulatory agenda. The Supreme Court's strong language in overturning that rule is thus highly instructive of the fate that EPA's Section 111(d) rule will ultimately suffer. As the Supreme Court explained:

> EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. When an agency claims to discover in a long-extant statute an unheralded power to regulate a 'significant portion of the American economy … we typically greet the announcement with a measure of skepticism.[27]

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22 *See* 79 Fed. Reg. at 34,838 ("while states must begin to make reductions by 2020, full compliance with the CO_2 emission performance level in the state plan must be achieved no later than 2030.")

23 RIA Table 3-8.

24 RIA at 3-32.

25 *Id.*

26 79 Fed. Reg. at 34,915-17.

27 *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2444 (2014) (emphasis added) (citation omitted).

As the Court stated, "[w]e expect Congress to speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'"[28]

These words apply with even greater force to EPA's Section 111(d) proposal than they did to the Tailoring Rule. EPA has seized upon what can only be described as a backwater provision of the CAA (Section 111(d))—a provision that has been on the books since 1970 and yet has only been used in a handful of instances—to justify a massive reorganization of perhaps the most central industry in America. In order to do so, it has had to concoct a new interpretation of Section 111(d) that is far different than the Agency's interpretation of the provision for more than 40 years. This new interpretation, however, and the massive arrogation of authority it would lead to, is so monumentally implausible as to place it far outside "the bounds of 'reasonable interpretation.'" *Utility Air Regulatory Grp.*, 134 S. Ct. at 1868, citing *Arlington v. FCC*, 133 S. Ct. 1868 (2013) . Congress not only failed to "speak clearly" in authorizing EPA's "vast[ly]…significant" intrusion into the power sector, the NSPS program that Congress legislated decades ago clearly forbids EPA's proposed course of action.

Beyond the obvious unreasonableness of EPA's attempted use of Section 111(d) to seize control of the power grid, EPA's proposed regulation suffers from numerous legal flaws, which can be grouped together in the following categories.

First, apart from the invalidity of EPA's new interpretation of Section 111(d), EPA lacks authority under that provision to issue *any* regulations applicable to coal EGUs. Section 111(d) prohibits EPA from issuing regulations governing a pollutant that is "emitted from a source category which is regulated under section 7412 of this title." Because CO_2 is obviously emitted from coal EGUs, and because EPA regulates coal EGUs under section 112 through its MATS regulation, EPA may not regulate CO_2 from coal EGUs under Section 111(d).

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[28] *Id.* at 19 (emphasis added).

Second, even if EPA does have authority to issue Section 111(d) regulations governing CO_2 emissions from coal EGUs, EPA's proposed regulations impermissibly intrude on state authority under Section 111(d) to "establish" standards of performance. Under Section 111(d), EPA's authority is limited to adopting a "procedure" under which "each State shall submit to the Administrator a plan which (A) establishes standards of performance…." EPA's proposed regulations are far more than procedural. They usurp state authority to "establish" performance standards by dictating to the states what the standards must be. Additionally, EPA has structured the regulations in a way that prevents States from, as provided in Section 111(d)(1)(B), considering "the remaining useful life of the existing source" to which a state-established performance standard applies.

Third, EPA's proposed regulations contradict the language, context, legislative history, and consistent past administrative construction of Section 111(d). Indeed, in twisting Section 111(d) to achieve EPA's desired result, the Agency has had to invent a lexicon of new and redefined terms never before used in the Section 111(d) program. For the first time, EPA has set state-by-state "goals," meaning legally enforceable mandates, for states to improve their power sector carbon intensity. But neither Section 111(d) nor EPA's Section 111(d) regulations authorize EPA to set binding statewide "goals;" the term "goal" is not even used in the statute or EPA's implementing regulations. Similarly, for the first time, EPA defines a "system" of emission reduction to be mandated reductions in the amount of time facilities within the regulated source category are allowed to operate. But forcing coal plants to reduce operation is not a "system" of emission reduction under Section 111(d) or any "system" at all. It is simply an extra-statutory and unprecedented *dictat* for sources to reduce operation.

Fourth, EPA cannot formally approve, and so make federally enforceable, state plan measures that apply to facilities that are not in the regulated source category. Nor can EPA impose a federal plan containing such measures. EPA's new "interpretation" of Section 111(d) encourages states to submit plans that contain what EPA calls, in its new lexicon, "portfolio" measures. These measures would be used, for instance, to increase the use of renewable energy and to induce the public to reduce electric consumption. The measures would be undertaken by states or third parties and, upon EPA approval, would become enforceable against those entities. Presumably, if EPA deemed a state's "portfolio" measures insufficient to meet EPA's emission-reduction "goals," EPA could impose a federal plan containing these "portfolio" measures. But no amount of interpretational legerdemain on EPA's part can even remotely read into Section 111(d) the authority to create federally enforceable obligations on entities that do not own or operate facilities within the regulated source category. The NSPS program authorizes standards to be set for and enforced against facilities within EPA-listed source categories. It does not apply to any other facilities.

Fifth, EPA's new "interpretation" of Section 111(d) requires it do further violence to the language and administrative history of that section by combining two source categories—coal boilers and natural gas turbines—into a single source category. Just three years ago, however, in its MATS rule, EPA decided that these two source categories could not be combined because to do so would lead to standards that coal EGUs could not meet.[29] But to achieve its intended purpose under Section 111(d), EPA has decided it must combine the source categories, precisely because the purpose of EPA's proposed rule is to set standards that coal EGUs cannot meet. That purpose, however, is not legitimate.

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[29] EPA, Mercury and Air Toxics Rule, Docket No. EPA-HQ-OAR-2009-0234, Response to Public Comments on Rule Amendments Proposed May 3, 2011, sec. 2 at 1-2 (Dec. 2011).

Sixth, EPA lacks authority to adopt its proposal because it can adopt Section 111(d) regulations only for source categories for which EPA has adopted corresponding regulations under Section 111(b). Neither EPA's new source proposal nor its modified/reconstructed source proposal, however, regulates the same source category as EPA's existing source proposal. In any event, EPA's new source proposal is not a legally valid regulation under Section 111(b).

Seventh, the proposed rules are ultra vires because Congress did not delegate authority to EPA to regulate the electric grid. That authority rests with the states as to retail transactions and FERC as to wholesale transactions. EPA's proposed regulations intrude on both state and federal authority.

Eighth, EPA's BSER "Building Block" analysis is riddled with flawed and arbitrary assumptions. EPA's analysis is built on a wholly uninformed view of the way the electric grid works, EPA's selection of 2012 as the base year is arbitrary, and each of its four building blocks is fundamentally untethered from the reality the Agency seeks to model.

Ninth, EPA's BSER analysis fails to take into consideration numerous important and relevant factors: (1) EPA improperly failed to include in the record the relevant information for most of the IPM model runs that it conducted; (2) EPA seriously underestimates the cost of complying with the rule and the impact of the rule on consumer electricity and natural gas prices; (3) EPA's analysis of the impact its proposal will have on the reliability of the power grid is seriously deficient; (4) EPA's natural gas analysis is deficient; (5) EPA failed to examine the public health and welfare harms that its regulations will cause by raising electric rates; (6) EPA failed to examine the effect of its proposal cumulatively with its other power sector regulations; (7) EPA failed to take due account of the stranded investment it is creating; (8) EPA far overstates the benefits of the proposed rule; (9) EPA's lifecycle analysis is deficient; (10) EPA failed to consider the environmental impacts of displacing coal generation with other generation sources; and (11) states cannot adopt the plans EPA is demanding, not even "interim" plans, within one year.

In sum, NMA urges EPA to withdraw the proposed rule.[30]

COMMENTS

I. Because Coal-Fired EGUs Are Regulated under Section 112, EPA Lacks Authority to Regulate Them under Section 111(d).

A. The Plain Language of Section 111(d) Prevents EPA from Issuing the Proposed Rule.

Section 111(d) applies only to a pollutant "for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this *title or emitted from a source category which is regulated under section 7412 of this title*." (Emphasis added.) Under the italicized language, EPA cannot issue Section 111(d) regulations governing CO_2 emissions from coal-based EGUs. The language clearly prevents EPA from regulating source categories which are regulated under Section 112, and coal EGUs clearly are so regulated.[31]

EPA's sole basis for claiming that it can issue Section 111(d) regulations governing CO_2 emissions from coal-fired EGUs stems from what the Agency asserts is an "ambiguity" in changes that the 1990 CAA Amendments made to Section 112.[32] As EPA points out, the Section 111(d) phrase "or emitted from a source category which is regulated under section 7412 of this title" originated in the House bill of the 1990 legislation and effects a substantive change to the

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30 EPA seeks comment on two alternative sets of state-specific emission rate goals—one set based on the same calculation methodology but with less stringent assumptions, and one based on a narrower definition of the "best system of emission reduction" that only covers fossil fuel-fired electric generating units. These alternative proposals are legally infirm for almost all the same reasons as EPA's primary proposal. NMA therefore does not discuss them further below, except as set forth in IV below.

31 "National Emissions Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," 77 Fed. Reg. 9,304 (Feb. 16, 2012).

32 EPA Legal Memo at 12.

preexisting version of Section 111(d).[33]Prior to 1990, Section 111(d) precluded EPA from regulating pollutants "for which air quality criteria have not been issued or which [are] not included on a list published under section 7408(a) or Section 112(b)(1)(A) of this title." Thus, under the prior version of Section 111(d), EPA could not issue regulations governing pollutants that were neither (a) NAAQS pollutants (pollutants for which air quality criteria have been issued or which are included on a list published under section 7408(a)) nor (b) hazardous air pollutants (HAPs) (pollutants that are listed for regulation under Section 112(b)(1)(A). As a result, under the prior version of Section 111(d), EPA could have issued Section 111(d) regulations governing CO_2 emissions from EGUs because CO_2 is neither a NAAQS pollutant nor a HAP.

The House language deleted the term "Section 112(b)(1)(A) and inserted the phrase "emitted from a source category which is regulated under section 7412 of this title." Thus, under the new version of Section 111(d), EPA may not issue regulations for pollutants that are neither (a) NAAQS pollutants nor (b) pollutants that are emitted *by a source category that is regulated under Section 112*. As a result, under Section 111(d) as it now exists, EPA cannot issue Section 111(d) regulations governing CO_2 emissions from EGUs because coal EGUs are a source category that is regulated under Section 112.

EPA agrees that the House language, which emerged from conference with the Senate bill and was adopted into law without change, clearly prevents EPA from issuing the regulations that it has proposed here.[34] The ambiguity that EPA relies on to trump this clear meaning stems from language which originated in the Senate version of the legislation and which was also

[33] *Id.; see also* 70 Fed. Reg. 15,994, 16,031 (Mar. 29, 2005).
[34] 70 Fed. Reg. at 16,031.

included in the legislation that Congress enacted into law.[35] The Senate language that EPA relies on was included in the "Conforming Amendments" section of the final bill.[36] Like the language in the House bill, it deleted the term "Section 112(b)(1)(A)" from the preexisting version of Section 111(d). "[I]n lieu thereof," it inserted the phrase "Section 112(b)."[37] As EPA recognizes, this Senate language was not included in the U.S. Code.[38]

The reason the Senate language could not be executed and was therefore not included in the U.S. Code is obvious. The necessity for the conforming amendment was superseded by the House language. The Senate's conforming amendment replaced "Section 112(b)(1)(A)" with "Section 112(b)" because Congress, in separately amending Section 112, had deleted Section 112(b)(1)(A). But the drafters of the conforming amendment failed to realize that Congress had (through the House language) deleted the reference in Section 111(d) to Section 112(B)(1)(A) and thus that it was not necessary to include the conforming amendment.

EPA itself recognizes that the Senate language was a "drafting error."[39] Yet EPA tries to bootstrap this error into a full-blown substantive "conflict" between the House bill and the Senate bill.[40] According to EPA the House language reflects the desire of the House to substantively amend Section 111(d), while the Senate language would merely keep Section 111(d) as it was, with only a technical, conforming amendment.[41] EPA deduces from this that Congress' overall intent is unclear.[42]

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[35] EPA Legal Memo at 26.
[36] *Id.*
[37] P.L. 101-549, Section 302.
[38] *See* 70 Fed. at 16,030 (citing Revisor's Note to 42 U.S.C. § 7411: the Senate amendment "could not be executed").
[39] 70 Fed. Reg. 15,994 16,031 (Mar. 29, 2005).
[40] *Id.* at 16,031-32.
[41] *Id.* at 16,031 ("The Senate amendment reflects the Senate's intent to retain the pre-1990 approach of precluding regulation under CAA section 111(d) of any HAP listed under CAA section 112(b).").
[42] *Id*.

Congress' intent, however, is not unclear. EPA seems to fail to grasp that the Senate, in passing the final legislation, adopted the House language. The Senate thus, like the House, intended to substantively amend Section 111(d). The fact that the Senate's conforming amendment survived into the final legislation does not demonstrate a conflict or ambiguity in the bill. It reflects a drafting mistake.

The U.S. Code is prima facie evidence of the laws of the United States.[43] As such, Code provisions can be displaced only where they are "inconsistent" with the statutes at large.[44] But "clerical errors" do not create inconsistencies.[45] Where a mistake in renumbering a portion of a statute to reflect other changes conflicts with a clear statutory provision, a court will conclude that the mistake is a mere "scrivener's error" that can be ignored.[46] Having recognized that the Senate language was a drafting error, EPA should have ignored the Senate language and given the bill as codified in the U.S. Code full effect.[47]

B. Even if Section 111(d) Is Ambiguous, EPA Lacks Authority to Issue the Proposed Rules.

Even assuming for the sake of argument that Section 111(d) is ambiguous, EPA, having insisted it is not free to ignore the Senate's conforming amendment, is not free to resolve that ambiguity by simply ignoring the House's substantive language. Although EPA may ignore

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[43] 1 U.S.C. § 204(a).

[44] *Stephan v. United States*, 319 U.S.C. 423, 426 (1943).

[45] *Am. Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336-37 (D.C. Cir. 2013).

[46] EPA's Legal Memo relies heavily on EPA's 2005 interpretation of Section 111(d), but that interpretation precedes *Am. Petroleum Inst*.

[47] *Id.; see also Chickasaw Nation v. United States*, 534 U.S. 84, 94 (2001) ("court [may] reject words as surplusage if inadvertently inserted or if repugnant to the rest of the statute ") (internal quotations and citations deleted). *See also Nat'l Mining Ass'n v. Kempthorne*, 512 F.3d 702 , 706 (2008) ("[C]ourts will not give independent meaning to a word where it is apparent from the context of the act that the word is surplusage … We have no qualms about [ignoring a particular word], for both Congress's intent and the error impeding it are plain to see (quotation marks omitted), citing *Am. Radio Relay League, Inc. v. FCC*, 617 F.2d 875, 879 (D.C. Cir. 1980); 2A Norman J. Singer, SUTHERLAND STATUTES AND STATUTORY CONSTRUCTION, § 47.37 (6th ed. 2002) ("A majority of the cases permit the elimination or disregarding of words in a statute in order to carry out the legislative intent or meaning"); Henry M. Hart, Jr. & Albert M. Sacks, THE LEGAL PROCESS 1375 (William N. Eskridge, Jr. & Philip P. Frickey eds., 1994) ("Courts on occasion can correct mistakes . . . when it is completely clear from the context that a mistake has been made.")).

language that results from a scrivener's error, EPA must otherwise give effect to all the language in the statute if possible.[48] As a White Paper published by the Federalist Society explained, both the Senate and the House language can be included in Section 111(b) in a way that makes grammatical and logical sense by authorizing EPA to regulate pollutants:

> which [are] not included on a list published under section 7408(a) *or 112(b) [Senate amendment] or emitted from a source category which is regulated under section 112* [House amendment] of this title.[49]

Under this reading, this phrase creates both pollutant-specific and source-category-specific limitations on EPA's ability to promulgate Section 111(d) regulations. The pollutants that EPA regulates under Section 111(d) cannot be either NAAQS pollutants or HAPs, and the source category that EPA regulates under Section 111(d) cannot be a source category that EPA regulates under Section 112. All of the language of both amendments can thus be harmonized into a coherent and sensible whole. EPA is prevented from double-regulating NAAQS pollutants and HAPs under Section 111(d), and the Agency is prevented from subjecting source categories that have been regulated under costly Section 112 regulation from additional costly regulation under Section 111(d).

EPA nowhere discusses why the House and Senate language cannot be read in this fashion.[50] Instead, EPA seems to believe that the only way that the Senate and House language

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48 *U.S. v. Menasche*, 348 U.S. 528, 538-39 (1955).

49 William J. Haun, The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants (Mar. 2013) at 10, available at http://www.fed-soc.org/publications/detail/the-clean-air-act-as-an-obstacle-to-the-environmental-protection-agencys-anticipated-attempt-to-regulate-greenhouse-gas-emissions-from-existing-power-plants.

50 The closest EPA comes is to maintain that the reading advanced here would result in the "ridiculous" result of barring EPA from regulating virtually any pollutant at all given the number of source categories that EPA regulates under Section 112 and given that these categories collectively emit almost every pollutant imaginable. EPA Legal Memo at 23, n. 22. In the first place, it would not have been obvious to Congress in 1990 that EPA would eventually regulate the number of source categories that it has under Section 112. More fundamentally, EPA is setting up a straw man. The intent of the House amendment was not to prevent EPA from regulating any pollutant at all, only to prevent EPA from regulating source categories under Section 111(d) that it was also regulating under Section 112.

can be combined into a single sentence is to reverse the order in which they appear above, so that the relevant language would prevent EPA from regulating:

> any air pollutant … which is not included on a list published under section 7408(a) *or emitted from a source category which is regulated under section 112* [House amendment] of this title or 112(b) [Senate amendment].[51]

EPA appears to think that because this reading is nonsensical—source categories are not regulated under Section 112(b)—it is free to skip over the actual language that Congress adopted in search of a more indirect expression of Congressional intent. EPA thus proffers an interpretation of Congress' intent that is wholly nontextual; it says that the purported inconsistency in the Senate's and the House's intent can be harmonized as follows:

> Where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category. Thus, if EPA is regulating source category X under section 112, section 111(d) could not be used to regulate any HAP emissions from that particular source category.[52]

But even EPA recognizes that this interpretation "does not give full effect to the House language, because a literal reading of the House language would mean that EPA could not regulate HAP or non-HAP emitted from a source category regulated under section 111."[53] EPA believes it is free to ignore the House language given EPA's views as to the general policies underlying the 1990 Amendments.[54] EPA, however, has it exactly backwards. "The cardinal principle of statutory construction is to save and not to destroy."[55]EPA thus must "give effect, if possible, to every clause and word of a statute, rather than to emasculate an entire section."[56]

In any event, EPA's view that Congress did not mean what it said in the 1990 amendment to Section 111(d) is unpersuasive. EPA proffers two reasons why Congress could not have

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51 70 Fed. Reg. at 16,031.
52 *Id.* at 16,031-02.
53 *Id.* at 16,032.
54 *Id.*
55 *Menasche*, 348 U.S. at 538 (internal citations omitted).
56 *Id.* at 539.

meant what it said, the second of which can easily be dismissed. EPA claims that the House language cannot truly reflect Congress' intent because that language is inconsistent with EPA's "historical[]" practice of regulating non-HAPs under that Section, even when those HAPs were emitted by a source category regulated under Section 112.[57] But Congress is obviously free to adopt legislation changing how an agency has previously regulated. Indeed, that is why Congress in the 1990 Amendments rewrote Section 112.[58] Since Congress' intentions must be sought first and foremost in the statutory text, *Engine Mfrs. Ass'n v. S. Coast Air Quality Mgmt. Dist*., 541 U.S. 246 . 252 (2004), the language of Section 111(d) takes precedence over EPA's musings over what Congress must have truly meant.

EPA also cites the "general thrust" of the 1990 Amendments in general, which EPA says is to regulate more pollutants rather than less. But obviously Congress can enact legislation with a general purpose but also include exceptions.[59] Moreover, the place in the 1990 Amendments where Congress' intent to regulate more pollutants is most clear is in Section 112, where Congress replaced EPA's authority under Section 112(b)(1)(A) to create a list of dangerous HAPs with a congressionally-created list under Section 112(b) of more than 100 HAPs.[60] Yet in the 1990 Amendments, Congress created an exception to the command in Section 112(c) that EPA regulate all source categories that emit the statutorily-listed HAPs if those pollutants are emitted in amounts above defined thresholds. In Section 112(n)(1)(A), Congress provided that EPA should regulate coal- and oil-fired EGU HAPs only if EPA found it "appropriate and necessary" to do so. There is therefore nothing inconsistent in Congress having an overall intent

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[57] 70 Fed. Reg. at 16,032.

[58] *New Jersey v. EPA*, 517 F.3d 574, 581-83 (D.C. Cir. 2008) (Congress comprehensively revised Section 112 to change how EPA regulates HAPs).

[59] *See, e.g., Natural Resources Defense Council, Inc. v. Reilly*, 976 F.2d 36, 41 (D.C. Cir. 1992).

[60] *See White Stallion v. EPA*, 748 F.3d 1222, 1230 (2014).

to regulate more rather than less substances but to also intend that certain pollutants as emitted by certain source categories would not be regulated.

Indeed, EPA itself recognizes that Congress' enactment of Section 112(n)(1)(A) entirely undercuts the Agency's interpretation of Section 111(d). As EPA says, Section 112(n)(1)(A) was included in the House version of the legislation along with the Section 111(d) language at issue here.[61] EPA further recognizes that Section 112(n)(1)(A) reflects Congress' intent to avoid subjecting EGUs to duplicative and costly regulation.[62] EPA maintains that it was perfectly consistent for the House, given the intent behind Section 112(n)(1)(A), to amend Section 111(d) to preclude EPA regulation of existing EGUs if the Agency determined to regulate them under Section 112.[63] EPA goes so far as to say that "[i]t is hard to conceive that Congress would have adopted section 112(n)(1)(A), yet retained the Senate amendment to section 111(d)."[64] On this basis, EPA posits that the Senate language must be a "drafting error and therefore should not be considered."[65]

EPA's reasoning up to this point is sound, particularly since, as EPA says, Legal Memo at 9, Section 111(d) is a little used provision, and so making it inapplicable to source categories that are regulated under Section 112 would not have been seen by Congress as a major reduction in regulation. Thus, it is understandable that a Congress concerned, as EPA says, with lessening regulatory burden would eliminate Section 111(d) regulation for source categories that were regulated under Section 112.

EPA's final conclusion from its line of reasoning, however, is not sound. EPA erroneously concludes that since the Senate language was included in the final bill even if by

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[61] 70 Fed. Reg. at 16,031.
[62] *Id.*
[63] *Id.*
[64] *Id.*
[65] *Id.*

mistake, the Agency must "consider" that language. As seen, however, EPA is free—indeed, is compelled—to disregard the Senate language precisely because it was a "drafting error."[66] In any event, EPA failed to realize that it could have given both the House and Senate language meaning in the manner posited by the Federalist Society paper without eviscerating the House language.

In sum, EPA cannot manufacture ambiguity where it does not exist, and it cannot invent meaning for statutory text which is not based on the text itself. EPA does not have authority to regulate EGU emissions of CO_2 under Section 111(d).

II. EPA Lacks Authority to Establish Emission Reduction Requirements that Are Binding on States.

Even presupposing that EPA has authority to issue Section 111(d) regulations governing EGU CO_2 emissions, EPA does not have authority to promulgate mandatory emission reduction requirements that state plans must meet. Further, EPA has intruded on state authority under Section 111(d)(1)(B) authority by preventing states from considering the "remaining useful life" of sources to which state standards of performance would apply.

A. Section 111(d) Bars EPA from Requiring States to Meet EPA-Set Emission Reduction Requirements.

Section 111(d) provides, in pertinent part, that EPA "shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant…." Under this language, EPA may not set emission reduction requirements for states. The Agency may establish a procedure for states to submit plans containing state-established standards, and it may approve or disapprove those plans to

66 *Am. Petroleum Inst.*, 714 F.3d at 1336-37.

determine if they are "satisfactory."[67] But EPA's power to disapprove a state plan is limited and cannot be used, as EPA is attempting to do here, to dictate a minimum required level of emission reduction.

1. EPA's role in developing standards in the first instance is to adopt a "procedure" for the submission of state plans.

Congress plainly did not give EPA authority under Section 111(d) to set a required level of emissions performance by facilities within the regulated source category. Congress merely provided that EPA should establish a "procedure" for the submission of state plans. EPA's proposed minimum standards are substance, not a procedure. EPA may not shoehorn into Section 111(d) authority to set substantive standards that Section 111(d) does not provide.[68]

2. Congress gave states, not EPA, authority under Section 111(b) to "establish" standards of performance.

In contrast, Congress plainly granted states the substantive authority to promulgate standards of performance. Section 111(d) specifically provides that "each State shall submit to the Administrator a plan which (A) *establishes* standards of performance…." (Emphasis added.)

It is true that that the definition of standard of performance in Section 111(a) provides that the "best system of emission reduction" is the system that, balancing the statutory factors, "the Administrator determines has been adequately demonstrated." But although EPA may arguably, in the context of Section 111(d), establish the "best system" on which a standard of performance may be based, it cannot also determine the performance standard, which is what EPA has proposed by establishing mandatory state emission "goals." EPA tries to hide this result by pretending that the emission reduction requirements that it proposes to impose on states are not actually performance standards. Throughout the preamble, EPA continually tries to make

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67 *See* CAA § 111(d)(2)(A).

68 *Am. Library Ass'n v. FCC*, 406 F.3d 689, 698 (D.C. Cir. 2005) (noting that an agency's "power to promulgate legislative regulations is limited to the scope of the authority Congress has delegated to it").

it seem that, in addition to establishing BSER, it is merely establishing "goals," leaving it to states to establish the standards of performance. For instance, the Agency states that it has "authority to define the BSER, as well as state goals," and that "each state's responsibility [is] to develop and implement standards of performance that will achieve its CO_2 goal."[69]

But EPA's attempt to create a false distinction between its "goals" and the standards of performance it requires states to formulate to meet these goals contradicts the statute. What EPA calls "goals" are self-evidently standards of performance as that term is defined in Section 111(a). As EPA readily concedes, the goals are "based on an assessment of the amount of emissions that can be reduced at existing fossil fuel-fired EGUs through the application of the BSER."[70] That is exactly what a standard of performance is under the statute: "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction."[71] Indeed, EPA proposes to formally define the "goals" as "emissions performance goals,"[72] which, because the goals are mandatory, is a euphemism for "emissions performance standards."[73]

What EPA calls "standards of performance" that it leaves to states to determine are not standards of performance at all within the meaning of Section 111(a) and (d). They are more

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[69] 79 Fed. Reg. at 34,835.
[70] *Id.* at 34,837.
[71] CAA § 111(a).
[72] *See* proposed 40 C.F.R. § 60.5765.
[73] The only authority that EPA cites for establishing mandatory "goals" is its regulations. EPA Legal Memo at 29-33. Its regulations provide for EPA to promulgate "guidelines" that states must follow. Under EPA's regulations, a "guideline" "reflects the application of the best system of emission reduction (considering the cost of such reduction" that has been adequately demonstrated." 40 C.F.R. § 60.22(b). In other words, the "guideline" is a performance standard. The fact that EPA is relying on its regulations to promulgate the rule at issue here, of course, does not make the rule lawful, given that the regulations itself are unlawful. *See Rapanos v. United States*, 547 U.S. 715, 753 (2006) ("curious appeal to entrenched executive error" unavailing). EPA says it is not "re-opening" these regulations in this current rulemaking, Legal Memo at 9, n.16. NMA is uncertain whether EPA, by this statement, means to assert that these regulations may not be challenged as a part of an appeal of EPA's Section 111(d) rules given the passage of time since they were adopted. Clearly, however, neither NMA nor anyone else could have anticipated, when these regulations were adopted, that EPA would use them to try to significantly reduce coal usage in the United States. Thus, an NMA challenge would not be foreclosed at this time. *See Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 131-32 (2012).

akin to state implementation plan measures that states would adopt to attain an EPA-established NAAQS. In trumpeting the supposed flexibility that the rule provides states, EPA explains the measures states can include in their plans to meet EPA's goals as follows:

Each state has the flexibility to choose how to meet the goal using a combination of measures that reflect its particular circumstances and policy objectives. While EPA identified a mix of four building blocks that make up the best system of emission reductions under the CAA, a state does not have to put in place the same mix of strategies that EPA used to set the goal. States are in charge of these programs and can draw on a wide range of tools, many of which they are already using, to reduce carbon pollution from power plants and meet the goal, including renewable energy portfolios and demand-side energy efficiency measures.[74]

None of these measures, by any stretch of the imagination, can be called performance standards. Under Section 111(a), a standard of performance is "a standard for emissions of air pollutants." State plan requirements that create obligations on third parties who are not within the regulated source category—for instance, to build more renewable generation or take responsibility for inducing consumers to use less electricity—are not "standards for emissions of air pollutants." Indeed, EPA's conception of BSER would require significant *increases* in natural gas generation and therefore in emissions from natural gas generators. There is no possible interpretation of the term "standard of performance" as a mandate to increase emissions.

Moreover, EPA's claim that these types of measures are "standards of performance" because they reduce emissions from the regulated source category[75] only serves to emphasize that EPA's "goals" are no different from performance standards. EPA's point is that states can meet the "goals" by (a) setting rate-based or mass-based limits on the regulated source category,

[74] *See* http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-framework.

[75] 79 Fed. Reg. at 34,903.

(b) adopting "portfolio" measures which have the effect of reducing generation (and therefore emissions) from the source category, or (c) some combination of both approaches.[76] Whatever plan the state submits, however, the plan must ensure that emissions from the regulated source category must decline to the level of the goals.[77] Thus, directly or indirectly, EPA is dictating the level of emission reduction regulated sources must make, and it has determined that level by applying the BSER factors. As a result, EPA is promulgating performance standards within the meaning of Section 111(a). Under Section 111(d), however, Congress gave states, not EPA, authority to establish those standards.

3. Congress' decision not to require states to submit Section 111(d) performance standards as a part of formal Section 110 state implementation plans confirms EPA's limited Section 111(d) role.

Section 110 provides for states to submit formal state implementation plans (SIPs) to meet a number of standards. Typically, where a Section 110 SIP is required, Congress has adopted a separate provision authorizing EPA to set the applicable standards. For instance, Section 109 provides for EPA to establish NAAQS, and Section 110(a) provides that states must submit SIPs meeting those NAAQS.[78] In places, Section 110 itself creates substantive requirements that state plans must meet. For instance, Section 110(a)(2)(D)(i)(I) requires that state plans include measures to prevent significant contribution to nonattainment of the NAAQS in downwind states.

Congress, however, did not require states to submit formal Section 110 SIPs containing the performance standards that they adopt under Section 111(d). Instead, Section 111(d) provides that EPA is to establish a "procedure similar to that provided by Section 7410" for states to submit plans. Congress' decision not to subject state Section 111(d) plans to the full

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76 79 Fed. Reg. at 34,902-03.
77 *See* proposed rule § 60.5740(a)(3)(ii).
78 *See also* Section 1110(a)(2)(A) requiring SIPs to meet "other applicable requirements of this Act."

weight of the Section 110 SIP review process indicates Congress' intent that EPA would play a lesser role in approving or disapproving state Section 111(d) plans than would occur under the formal Section 110 process.[79] This is understandable because, unlike formal Section 110 SIPs, where states must meet congressionally- or EPA-established standards, Congress did not establish standards under Section 111(d) nor did it authorize EPA to do so. It left that task to the states.

Of course, by requiring that EPA establish a "procedure similar to that provided by Section 7410," and by giving EPA the authority to promulgate a federal plan if the state plan is not "satisfactory," CAA § 111(d)(2)(A), Congress gave EPA a role to play in reviewing and potentially even disapproving state plans. But EPA's authority to disapprove an unsatisfactory state plan obviously cannot be transformed into EPA authority to set performance standards in advance that states must meet, which is what EPA has proposed to do here. And although EPA could undoubtedly issue nonbinding guidance advising states of factors EPA would consider in finding a state plan unsatisfactory, the guidance could not intrude into the state's ultimate authority to "establish" the performance standards.

In this regard, it must be kept in mind that EPA's disapproval authority under Section 111(d) is limited. As in other cases where the CAA delegates authority to states to determine emission standards in the first instance, EPA may disapprove a state determination only where the state acted "unreasonably."[80]Moreover, as the Supreme Court has stated, because the statute gives states "considerable leeway" and "places primary responsibilities and authority with the

[79] *Cf. Russello* v. *United States*, 464 U.S. 16, 23 (1983) ("Where Congress includes particular language in one section of a statute but omits it in another . . . , it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citation and internal quotation marks omitted). This intent is underscored by Congress' use of the word "procedure," which, as noted, further demonstrates Congress' intent not to provide EPA with a substantive role in setting performance standards.

[80] *See, e.g., Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461, 484-89 (2004) ("*ADEC*") (EPA authority over state best available control technology determinations is limited "to ensur[ing] that a State's BACT determination is reasonably moored to the Act's provisions.").

States," EPA must give "appropriate deference" to the state.[81] EPA may step in "[o]nly when a state agency's BACT determination is not based on a reasoned analysis" and is "arbitrary."[82]When it does step in, the Agency has "the production and persuasion burdens."[83]

Thus, although EPA ultimately could disapprove a state Section 111(d) plan if it is unreasonable and therefore not "satisfactory," EPA would bear the burden of showing that the state acted unreasonably. As a result, it cannot dictate substantive outcomes, as it has proposed to do here, nor can it use its limited disapproval authority to eviscerate state authority under Section 111(d) to establish performance standards.

B. EPA Improperly Deprives States of Authority to Consider the Remaining Useful Lives of Regulated Sources.

Under Section 111(d)(1)(B), "[r]egulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." EPA implemented this requirement in its general Section 111(d) regulations,[84] by providing that states may deviate from EPA-mandated guidelines for a specific facility based on, among other factors, "[u]nreasonable cost of control resulting from plant age."

EPA states that, while its proposed rule does not explicitly provide for state consideration of the remaining useful lives of individual facilities, it does so implicitly through the "flexibility for states to design their own measures." 79 Fed. Reg. at 34,925. According to EPA, "States are free to specify requirements for individual EGUs that are appropriate considering the remaining

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81 *Id.* at 490-91 (internal quotations omitted).
82 *Id.* (internal quotations omitted).
83 *ADEC*, 540 U.S. at 494 (emphasis added).
84 40 C.F.R. § 60.24(f).

useful life and other facility-specific factors."[85] The one important caveat, however, is that states must meet the EPA-mandated "goals." As a result, if a state exempts a source from emission-reduction requirements because of is short remaining useful life, it must compensate by requiring other sources to make further reductions than they would otherwise make.[86]

EPA's attempt to rationalize its compliance with the remaining useful life provision of Section 111(d) lacks credibility. Under Section 111(d), states first establish performance standards and then, in "applying" those standards to a particular source, they may consider remaining useful life. In this context, "applying" the standards while considering remaining useful life obviously means requiring fewer emission reductions than might otherwise be required—for instance, by exempting the source from the standard, giving the source a longer period to comply, or applying a lower standard. As EPA interprets this provision, however, if a state applied the "remaining useful life" factor to a source in this fashion, another source would have to make even more emission reductions than it would otherwise be required to make under the BSER as applied to that other source. In other words, the source making the additional, compensating emission reductions would be held to a standard that is not BSER but "better than BSER." EPA has no authority to apply such a standard to that other source.

EPA also deprives states of their authority to consider the remaining useful life of sources for another reason. In order to comply with other EPA regulations, a number of units in different states have made significant pollution control investments that have had the effect of extending the useful lives of these units. EPA's proposed regulations, however, are so stringent that some of these units will now be forced to close.[87] Under Section 111(d)(1)(b), states are authorized to

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85 *Id.*
86 *Id*. at 34,925-26.
87 *See* discussion at IX.C below.

consider recent life extensions of existing units in determining whether to apply standards that will force these units to close prematurely. EPA's proposal prevents them from doing so.

III. Defining BSER as Requiring Coal EGUs to Significantly Reduce and Even Retire Generation Is Unlawful under Section 111(d).

A. Introduction.

Contrary to all EPA precedent in the more than forty-year history of the NSPS program, EPA has proposed to adopt performance standards based on the premise that requiring facilities within the regulated source category to dramatically reduce production is a "system of emission reduction" within the meaning of Section 111(a). Thus, under EPA's proposed standards, the "system of emission reduction" for coal EGUs that the Agency deems "best" is the requirement these facilities reduce generation in the amount necessary to meet EPA's state-by-state "goals."[88] EPA estimates its proposal will, on average across the United States, reduce coal generation by 22% in 2020, rising to 27% in 2025.[89] Indeed, EPA's view is that the "best system of emission reduction" for coal EGUs in twelve states would be to not operate those EGUs at all.[90]

That EPA would pursue this course is not surprising given that it started with the predetermined goal of sharply cutting power sector GHG emissions. The President mandated this result by announcing his Administration's goal of putting the country on a path of reducing U.S. GHG emissions by 17% by 2025 and 83% by 2050, as compared with 2005 emissions.[91] As the President noted in his Presidential Memorandum directing EPA to issue its proposed

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88 EPA Legal Memo at 13-16.

89 Regulatory Impact Analysis ("RIA") at Table 3-11.

90 *See* EPA's spreadsheet at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents-spreadsheets.

91 *See* White House Press Release, "President to Attend Copenhagen Climate Talks," November 25, 2009, available at http://www.whitehouse.gov/the-press-office/president-attend-copenhagen-climate-talks.

regulations, the power sector emits 40% of all GHGs in the economy.[92] Since coal accounts for 75% of this 40% figure,[93] and since there is no feasible way of reducing CO_2 emissions from coal plants, achieving the President's goals requires a significant reduction in coal generation.

To achieve the predetermined result of slashing coal generation through the NSPS program, EPA was forced to reinvent the statutory BSER standard. Throughout the long history of the NSPS program, in issuing performance standards for more than 70 categories of sources, EPA has never determined that simply forcing regulated facilities to operate less constitutes BSER. For instance, under EPA's Section 111(d) regulations, the Agency has never required that large municipal waste combustors combust less waste,[94] that municipal solid waste landfills accept less waste,[95] that sulfur acid production units produce less sulfuric acid,[96] or that hospital/medical/infectious waste incinerators burn less waste.[97] Without exception, EPA has determined BSER by examining "adequately demonstrated" technology that can be cost-effectively installed at facilities within the regulated source category.[98] Under this approach, regulated facilities are not required to reduce production, only to install technically and economically feasible technology or to make other types of performance improvements at the facility in order to reduce emissions.[99]

This approach, however, if applied to coal EGUs, would not create the amount of CO_2 emission reductions that EPA's preset agenda demands. As EPA recognizes, there is no "end-of-the-pipe" technology that can cost-effectively reduce CO_2 emissions from coal EGUs, as even

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92 Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2003, available at http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

93 EPA Climate Change website, http://www.epa.gov/climatechange/ghgemissions/sources/electricity.html.

94 *See* 40 C.F.R., Subpart Cb.

95 *See* 40 C.F.R., Subpart Cc.

96 *See* 40 C.F.R., Subpart Cd.

97 *See* 40 C.F.R., Subpart Ce.

98 See EPA's Part 60 regulations.

99 *Id.*

the Agency agrees that carbon capture and sequestration (CCS) technology does not fit the definition of BSER for existing coal EGUs.[100] The only technology available to reduce CO_2 emissions from coal EGUs is efficiency improvements, but even under EPA's highly exaggerated estimate of the efficiency improvements that can be made at coal EGUs, these improvements would reduce CO_2 emissions by only 6%.[101] This amount is far below the amount that the President and EPA had determined was necessary.[102]

Deciding that "creativity" was required in construing the statute to produce the desired result, EPA developed two alternative interpretations of BSER that would allow the Agency to define reduced production as a "system" of reducing coal EGU emissions. Under the first alternative, BSER is defined as four building blocks: (a) improving the efficiency of existing coal EGUs by 6%, (b) environmental dispatch, whereby large amounts of combined cycle natural gas generation are substituted for coal generation; (c) the further reduction of coal generation through the substitution of nuclear and renewable generation, and (d) the reduction of electricity consumption to further reduce coal generation.[103] Although only block one is actually based on a system for reducing emissions from the source category being regulated, as BSER has been applied in the past, EPA nevertheless claims that all four of these building blocks qualify as BSER. According to EPA, "the integrated nature of the electricity grid and the fungibility of electricity and electricity services" make it appropriate to label blocks two, three and four as "components" of a "system" of emission reduction for the regulated category, on the theory that these blocks will reduce production of coal EGUs and thereby reduce their emissions. *Id.* at 14-15.

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[100] 79 Fed. Reg. at 34,836.
[101] 79 Fed. Reg. at 34,861.
[102] *See* White House Release, President to Attend Copenhagen Climate Talks, (November 25, 2009) announcing goal of reducing greenhouse gas emissions by 17% below 2005 levels in 2020 and 83% by 2050.
[103] EPA Legal Memo at 14.

Perhaps concerned at the complete lack of precedent for defining a "system" of reducing emissions from a source category as including measures that are not implemented at the facilities being regulated, EPA's alternative definition of BSER does not include blocks two, three and four as BSER "components."[104] Under this alternative, BSER would consist of block one plus "the reduction of affected fossil fuel-fired EGU mass emissions achievable through reductions in generation of specified amounts from those EGUs."[105] But this is mere subterfuge, since EPA determined these "specified amounts" of reduced generation through the application of all four blocks.[106] Given that under both alternatives, blocks two, three and four are used in conjunction with block one to set the desired amount by which coal EGUs must reduce generation, it is hard to understand the difference between the two alternatives, other than the fact that, under the second alternative, EPA can pretend that the latter three building blocks are not actually a part of BSER.

EPA's inventive new reading of BSER, however, stretches the language of Section 111(a) far beyond the breaking point. The plain meaning of Section 111(d), the legislative history of that section, and the long administrative history of the NSPS program show that EPA's attempt to arrogate to itself the power to redesign the power grid cannot stand.

B. The Language and Structure of the CAA Confirm that Congress Did Not Give EPA Authority under Section 111(d) to Reengineer the Electric Grid.

1. EPA's reinterpretation of its Section 111(d) authority exceeds the bounds of reasonable statutory construction.

The breadth of EPA's proposal is stunning. At EPA's direction, every state would have to completely alter the way their portion of the electric grid operates. In the Agency's formulation of the "best" system for meeting EPA's mandatory goals, states would "re-dispatch"

[104] *Id.*
[105] *Id.* at 15-16.
[106] *Id.*

power flow so that natural gas combined cycle generators would increase their capacity factors to 70%, even though only 10% of gas plants achieved that rate of production in 2012, a year of unprecedented low natural gas prices.[107] All "at risk" nuclear facilities would be deemed to be no longer "at risk"—and the reasons these facilities are "at risk" ignored—and would continue operating.[108] States that do not have access to renewable resources would now be required to significantly ramp up the use of those resources.[109] Electricity consumption would be cut by 2030 at a level that is more than 11% below what it would otherwise be[110]—a level that is little higher than today.[111] This despite the fact that the United States is expected to add about 2.5 million people per year[112] and presumably the country will grow economically.

Grid operations would be transformed. As the North American Electric Reliability Corporation (NERC) observed, EPA "proposes a very different mix of power resources than we have today."[113] Federal Energy Regulatory Commission (FERC) Commissioner Phillip D. Moeller recently testified that "[i]f it isn't already obvious, the title of the proposed rule, the Clean Power Plan, makes it clear that *EPA is creating national electricity policy*."[114] Similarly, FERC Commissioner Tony Clark described the proposed rule as follows:

> More than any regulation I have seen during the time that I have been involved in the energy sector, *this EPA proposed rule has the potential to comprehensively reorder the jurisdictional relationship between the federal government and states as it relates to the regulation of public utilities and energy development.*

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107 79 Fed. Reg. at 34,862-66. *See also* discussion below at VIII.D and IX.D.

108 *Id.* at 34,870-71.

109 *Id.* at 34,866-70.

110 RIA, Table 3-3, p. 3-17

111 EPA projects 2012 U.S. electricity sales to be 3,716,825 GWh. It projects 2030 U.S. electricity sales under its fourth building block to be 3,792,371 GWh, only about 2% more than its projected 2012 level. It projects 2030 business-as-usual electric sales to be 4,267,504 GWh, more than 11% higher than its building block four case. *See* Data File: GHG Abatement – Scenario 1 (XLS) and Data File: GHG Abatement – Scenario 2 (XLS) (corresponding to EPA option 1).

112 Census Bureau, http://www.census.gov/population/projections/data/national/2012/summarytables.html.

113 NERC, Media Release, Reliability Review of Proposed Clean Power Plan Identifies Areas for Further Study, Makes Recommendations for Stakeholders, available at http://www.nerc.com/Pages/default.aspx,, at 1.

114 Moeller House E&C Testimony at 1 (emphasis added).

> Up until this point, utilities have been regulated through the influence of a number of governmental entities. State legislatures, governors, public utility commissions, state energy offices, state departments of environmental quality, EPA and FERC, to name some of the major players, all had a role to play. Any one entity could exert an influence on the process, but they each had their own niche.
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> EPA's proposed 111(d) regulations would dramatically alter these traditional lines of authority by creating a new paradigm of oversight of net carbon emission from a state.
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> *After an implementation plan is approved by the EPA, a state will have lost its ability to chart its own course as to how it regulates public utilities and its energy sector as a whole.* To use just one example, if a future legislature, decides that its renewable portfolio standard is not working for the citizens of its state, that legislature may effectively be prevented from changing course, because its "EPA-approved" RPS will still be in full effect; and likely enforceable by either the EPA or subject to a private party lawsuit. The same would apply to any future state utility commission action to the degree it implicates an EPA approved plan. *And because basically everything in the electricity sector affects carbon output in some manner, if a state "plays ball" with the EPA, the proposed rule could effectively lock a state into a comprehensive carbon integrated resource plan that can only be changed with the acquiescence of the EPA.*[115]

Of course, EPA says that it has used its building blocks only to construct a hypothetical "best system" of cutting back coal generation and that states are free to meet EPA's carbon intensity goals any way they want.[116] In other words, states are free to meet their goals in ways that EPA thinks are less than best. But given the severity of EPA's goals, as emphasized by the extreme building block assumptions EPA used to calculate them, the purpose and effect of the rule would be to revolutionize the way the nation produces and consumes electricity. Indeed, the rule is so transformational that, as discussed in more detail below, several Independent System

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115 Written Testimony of Commissioner Tony Clark, Federal Energy Regulatory Commission, Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives, Hearing on FERC Perspective: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid, at 4-7 (emphasis added).

116 74 Fed. Reg. at 34,897.

Operators are warning that the grid cannot operate reliably the way EPA wants or that electric costs to keep the grid reliable will skyrocket.[117]

The precedent EPA's new interpretation would set, however, is not limited to just the power sector. It would apply to setting existing-source performance standards throughout the economy. Every source category that EPA regulates could, in theory, be forced to reduce production if EPA, based on an economy-wide "BSER" analysis, determines that substitutes are available. EPA, for instance, could determine, under the guise of adopting performance standards, that petroleum refineries must reduce production because EPA thinks that the use of more electric vehicles is "adequately demonstrated" and cost-effective.

Congress, however, did not even remotely authorize EPA to transform the electric grid or any other sector of the economy. As the Supreme Court explained last term in overturning EPA's Tailoring Rule:

> EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. When an agency claims to discover in a long-extant statute an unheralded power to regulate a 'significant portion of the American economy … we typically greet the announcement with a measure of skepticism.[118]

As the Court stated, "[w]e expect Congress to speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'" *Id.* at 19 (citing *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000)).

> These words apply with even greater force to EPA's Section 111(d) proposal than they did to the Tailoring Rule. EPA has seized upon a provision of the CAA (Section 111(d)) that has been on the books since 1970 and yet has only been used in a handful of instances[119] to justify a massive reorganization of one of the most important industries in America. In order to do so, it has had to invent a new interpretation of Section 111(d) that is far different from the interpretation of the

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117 *See below at IX.C.*
118 *Utility Air Regulatory Group v. EPA*, 134 S. Ct. at 2444 (citation omitted).
119 EPA Legal Memo at 9.

provision for its more than 40-year history.[120] This new interpretation, however, and the arrogation of authority it would lead to, is so monumentally implausible as to place it far outside "the bounds of 'reasonable interpretation.'"[121]

2. EPA's reinterpretation of BSER contradicts the plain meaning of Section 111(a).

a. The language of Section 111 provides for performance standards to be set for facilities within a regulated source category.

The establishment of performance standards under Section 111 is a two-step process. First, EPA creates a list of "categories of stationary sources" which "cause[], or significantly contribute[] to, air pollution which may reasonably be anticipated to endanger public health or welfare."[122] EPA's regulations define the term "stationary source" to mean a "building, structure, facility, or installation."[123]

Once EPA lists a source category, it establishes standards of performance for new sources *within such category*."[124] In other words, having listed a category of "building[s], structure[s], facilit[ies], or installation[s]," the Administrator must establish standards which apply to those sources. In the same vein, the statute defines "new source" to mean "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 *which will be applicable to such source*."[125]

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[120] *Cf. INS v. Cardoza-Fonseca*, 480 U.S. 421, 446, n.30 (1987) ("An agency interpretation of a relevant provision which conflicts with the agency's earlier interpretation is 'entitled to considerably less deference' than a consistently held agency view."); *Barnett v. Weinberger*, 818 F.2d 953, 961 (D.C. Cir. 1987) ("It is well established that the prestige of a statutory construction by an agency depends crucially upon whether it was promulgated contemporaneously with enactment of the statute and has been adhered to consistently over time.").

[121] *Utility Air Regulatory Grp.*, 134 S. Ct. at 2442, citing *Arlington v. FCC*, 133 S. Ct. at 1868. *See also MCI Telcomms. Corp.* v. *AT&T,* 512 U.S. 218, 231 (1994) (disapproving agency statutory interpretation as leading to "highly unlikely" result).

[122] CAA § 111((b)(1)(A).

[123] 40 C.F.R. § 60.2.

[124] CAA § 111((b)(1)(B) (emphasis added).

[125] CAA § 111((a)(2) (emphasis added).

This structure is imported into Section 111(d), except that the State establishes the performance standards. States must submit plans which establish standards "for any existing source for any air pollutant … (ii) *to which a standard of performance under this section would apply if such existing source were a new source* …."[126] Thus, although EPA can call for statewide plans, those plans must still contain standards of performance *that apply specifically* to the source category that EPA has listed and for which the Agency has set performance standards for new sources under Section 111(b).

b. Forced reductions in production is not a "system" of emission reduction under Section 111(a).

EPA thinks there is room within this regulatory structure to define a standard of performance as a limit on the amount a facility can operate on the theory that limiting operations is a "system" of emission reduction. But EPA's new view of BSER makes no semantic sense. The dictionary definition of the word "system" is "a regularly interacting or interdependent group of items forming a unified whole."[127]A requirement that a facility limit production in order to reduce emissions is not a "system" of emission reduction or any kind of "system" at all. It is simply a limit on production. If Congress had intended to authorize EPA to reduce emissions by forcing facilities to cut back production, it could have done so in a considerably less convoluted way than EPA would now have it.[128] Indeed, in other parts of the statute, EPA did just that.[129]

Moreover, the "system" that EPA has constructed—the "regularly interacting or interdependent group of items forming a unified whole"—is not a "system" of reducing emissions at coal plants but in reality is EPA's reimagining of the electric utility system.

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[126] CAA § 111(d).

[127] Merriam-Webster Online Dictionary, http://www.merriam-webster.com/dictionary/system.

[128] *See Eli Lilly & Co. v. Medtronic, Inc.*, 496 U.S. 661, 667 (1990) (rejecting interpretation of statute because there would have been "infinitely more clear and simple ways of expressing" that interpretation and "it is hard to believe the convoluted manner petitioner suggests was employed [to reach that interpretation] would have been selected [by Congress]").

[129] *See* discussion below at III.B.4.

According to EPA, the "regularly interacting or interdependent group of items" in this system are EPA's building blocks, which it calls "components" of this system.[130] But natural gas, nuclear, renewable, and energy efficiency resources are obviously not components of coal plants; they are components of an electric utility system. Under Section 111, however, BSER is not the "best system" for operating a state's utility system. It is the best system for reducing emissions from the source category being regulated.

As EPA has held for the entire history of the Section 111 program, a "system" for reducing emissions under Section 111(a) consists of pollution control technology or other physical or operational changes that can be made at facilities within the regulated source category. The end product of this system is the establishment of the "*degree* of emission limitation," typically a limit on the rate of emissions, that this system can produce.

Apart from the fact that this is the only natural reading of the language, this reading is obvious from reviewing Section 111(a) in its context within Section 111. For instance, Section 111(h) gives EPA authority to promulgate a "design, equipment, work practice, or operational standard, or combination thereof" where the Agency determines that it is "not feasible to prescribe or enforce a standard of performance." Under Section 111(h)(2), it is not "feasible" to establish a standard of performance where "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations." Congress thus contemplated that a standard of performance would require the installation of a "conveyance" at the source that is "designed to emit or capture" the regulated pollutant, and Congress also contemplated that

[130] 79 Fed. Reg. at 34,852.

emissions through that "conveyance" would be measured. Only if the regulated pollutant is not emitted through a "conveyance" or emissions through the conveyance could not be measured would the Administrator be authorized to implement an alternative system to reduce emissions. This system would be "a design, equipment, work practice, or operational standard" and so would also be applied directly at the source being regulated. Indeed, under Section 111(h)(1), "[i]n the event the Administrator promulgates a design or equipment standard under this subsection, he shall include as part of such standard such requirements as will assure the proper operation and maintenance of any such element of design or equipment."

Other portions of Section 111 confirm that performance standards must be based on technology or other improvements made at the source. Section 111(b)(3), for instance, provides that EPA "shall, from time to time, issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section." And Section 111(b)(5) provides that "[e]xcept as otherwise authorized under subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate *any particular technological system of continuous emission reduction* to comply with any new source standard of performance." In other words, EPA may set the emission standard, but the choice of technology to meet the standard remains with the source.

Furthermore, EPA seems to forget that the definition of standard of performance applies equally to new sources and to existing sources under Section 111(d). In fact, because Section 111(d) is a provision of such limited applicability (as has proved to be the case in practice), Congress' intent behind Section 111(a) can best be understood in the context of new sources (where EPA has promulgated emissions standards for more than 70 source categories) rather than existing sources. Presumably not even EPA would contend that a limitation on the amount of time a new facility can operate, or even an outright ban on construction of the facility, could even remotely be considered to be a "system" of reducing that facility's emissions. As discussed more fully below as to the legislative history of Section 111, the NSPS program was intended to be a way of promoting growth, not limiting growth.

In sum, the language of Section 111 supports EPA's long and consistent reading of that provision. It does not support EPA's new interpretation.

3. In any event, EPA has no authority to apply BSER on a statewide basis.

In Section II above, NMA showed that EPA's proposal to set binding state-by-state emission reduction "goals" improperly intrudes on state authority to "establish" performance standards in Section 111(d) plans. EPA's proposal to set state goals has an additional flaw. Standards of performance cannot be established on a state-by-state basis; they must be established on a unit-by-unit basis.

This is obvious from the language of Section 111(d), which provides for EPA to adopt regulations calling on states to submit plans establishing "standards of performance for *any existing source*." Thus, standards of performance must be established on a source-by-source basis, not a state-by-state basis. Indeed, in an early NSPS case, the D.C. Circuit held that EPA could not combine into a single source multiple units at a single plant. As the Court stated, "[t]he regulations plainly indicate that EPA has attempted to change the basic unit to which the NSPSs apply from a single building, structure, facility, or installation (the unit prescribed in the statute) to a combination of such units. The agency has no authority to rewrite the statute in this fashion."[131] If EPA cannot combine multiple units at a single plant for the purpose of

[131] *ASARCO Inc. v. EPA,* 578 F.2d 319 (D.C. Cir. 1978).

establishing performance standards, it certainly cannot combine multiple units, including units that are not even in the regulated source category, throughout the state for that purpose.

EPA tries to justify setting "goals" state-by-state as an exercise of its subcategorization authority, quoting its regulations that allow the Agency to "specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities, when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate."[132] Undoubtedly, EPA can categorize and subcategorize under Section 111(b)(2) "for the purpose of establishing" performance standards. But EPA must have a rational basis, grounded in the statute, to create categories and subcategories. If there are technological differences between types of facilities or differences in the types of fuel similar facilities use, EPA can create different categories and subcategories, as it has done many times in the past. In theory, geography could be the basis for subcategorizing to the extent there is some reason why geography affects the level of performance of various types of control technology that could be used as the basis for setting performance standards for coal EGUs. But EPA cites no such geographical distinctions here, and there obviously are none. The Agency's only "geographical" justification for setting state-by-state standards is that different states have different resource mixes and so should have different carbon-intensity goals.[133] But for the reasons discussed above, EPA does not have the authority to determine BSER for coal EGUs based on a state's utility system, and therefore differences in states' resource mixes is not a valid justification for subcategorizing on a state-by-state basis. Differences in statewide resource

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[132] 79 Fed. Reg. at 34,891.
[133] 79 Fed. Reg. at 34,855.

mixes is certainly not what EPA had in mind in its subcategorization regulations when it referred to "costs of control, physical limitations, geographical location, or similar factors."[134]

4. Section 111, read in context of other CAA provisions, confirms that EPA's new interpretation contradicts Congress' intent.

Section 111 is a classic example of 1970s-vintage, top-down, command-and-control regulation based on setting uniform performance standards that individual sources within a source category must meet.[135] Other similar CAA provisions include the PSD program from the same era, under which permitting authorities may require that facilities install "Best Available Control Technology" (BACT). Like Section 111 standards, BACT has traditionally consisted of "traditional end-of-stack" technologies.[136] As a result, as the Supreme Court noted in *Utility Air Regulatory Group*, "it has long been held that BACT cannot be used to order a fundamental redesign of the facility."[137] Thus, BACT standards cannot require coal EGUs, which are primarily baseload facilities, to significantly cut back generation, because doing so prevents them from fulfilling their baseload function.[138] The Supreme Court's holding applies with even greater force to the NSPS program, since performance standards set the "floor" for BACT standards and thus BACT standards can be more (but not less) stringent than performance standards. Under EPA's interpretation, however, NSPS standards could be considerably more stringent than BACT standards, because NSPS standards could force the facility to reduce operation and could even force the facility to close (as is the case under EPA's regulations in 12 states).

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[134] 79 Fed. Reg. at 34,891.

[135] *See, e.g.,* Thomas W. Merrill, Symposium: Innovations in Environmental Policy: Explaining Market Mechanisms, 2000 U. Ill. L. Rev. 275; Dennis D. Hirsch, The National Symposium on Second Generation Environmental Policy and the Law: Symposium Introduction: Second Generation Policy and the New Economy, 29 Cap. U.L. Rev. 1.

[136] *Utility Air Regulatory Group v. EPA*, 134 S. Ct. at 2435.

[137] *Id.*

[138] *Id.*

The Section 112 hazardous air pollutant program is another example of top-down, technology-based standards. But, even stringent Maximum Achievable Control Technology (MACT) standards cannot require a reduction in the hours of the year in which a facility can operate. Instead, these standards require that the facilities install control technology so that, while operating, they at least match the "emission control that is achieved in practice" by the best-controlled sources."[139]

These top-down technology-based programs contrast with other, more modern CAA programs that set (or provide for EPA to set) absolute limits on emissions. For instance, the Title IV acid rain program sets nationwide limits on EGU emissions of SO_2 and NO_x. Title IV was adopted as a departure from the traditional command-and-control approach because top-down standard-setting was seen as inflexible and inefficient.[140] Having adopted Title IV, Congress obviously knows how to legislate caps on emissions that could require facilities to reduce operation. The fact that Congress did not adopt that approach for the NSPS and similar programs shows that Congress' intent in that regard was intentional.[141]

5. Congress cannot be understood to have delegated broad authority to EPA to regulate outside its area of expertise.

Under EPA's longstanding approach to defining a "system of emission reduction," EPA acts within its area of expertise in determining how a facility can cost-effectively control air pollution. But the power EPA is asserting with its new definition of "system" takes it far afield of its area of expertise and requires EPA to make judgments as to how grid operations could be reordered to provide substitute sources of electricity for coal generation. These sorts of

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[139] CAA § 112(d)(3).

[140] Lauraine G. Chestnut & David M. Mills, "A Fresh Look at the Benefits and Cost of the U.S. Acid Rain Program," Journal of Environmental Management 77, 252-266 (2005).

[141] *See Central Bank of Denver v. First Interstate Bank of Denver*, 511 U.S. 164, 176-77 (1994) (failure of Congress to include a specific provision in one part of statute, where it included that provision in another, is evidence of Congress' differing intent for the two provisions).

judgments would be daunting even for state and federal electric utility regulators. There is no reason to suppose that Congress would have delegated to EPA the authority to make these types of energy policy judgments given that EPA, as an environmental regulator, does not have the expertise to make them.[142] As the Kansas Corporation Commission, a true electric regulator, has pointed out, the rule reflects EPA's "understandable but serious lack of understanding of the electrical system, which is outside its area of expertise."[143]

Indeed, as interpreted by EPA, the guideposts that Congress established in the BSER definition become a virtually standardless grant of authority to the Agency. For instance, the term "adequately demonstrated" is an easily-understood limitation on EPA authority to establish traditional emissions standards for various types of facilities. EPA can examine (as it has many times in the past) performance levels of various types of pollution control equipment, test results and relevant literature. But there is no meaning in the term "adequately demonstrated" in the context of EPA's reimagined electric grid. Obviously, the grid has never operated the way EPA now desires it to operate nor has Congress supplied any factors EPA should examine in determining whether the grid has been "adequately demonstrated" to operate as EPA now wants. Similarly, while EPA can easily consider the "cost" of pollution control equipment in making traditional BSER determinations, Congress has supplied EPA no basis to determine whether the cost of its reengineered grid is acceptable. Under EPA's conception, there would no governing principle that would guide the Agency in determining whether cost impacts of 2% or 200% were acceptable.

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[142] *See Adams Fruit Co., Inc. v. Barrett*, 494 U.S. 638, 650 (1990) ("Although agency determinations within the scope of delegated authority are entitled to deference, it is fundamental 'that an agency may not bootstrap itself into an area in which it has no jurisdiction,'" *quoting Federal Maritime Comm'n v. Seatrain Lines, Inc.*, 411 U.S. 726, 745 (1973). *See also Natural Gas Pipeline Co. of America v. FERC*, 655 F.2d 1132, 1141-42 (D.C. Cir. 1980) (because agency interpretation was "virtually unprecedented" and no agency expertise is involved, "court has the preeminent responsibility to independently scrutinize and decide all jurisdictional issues").

[143] Comments on the proposed rule of the Kansas Corporation Commission at 23.

The lack of governing standards in EPA's view of BSER would pose an even more difficult problem for courts. Under normal principles of administrative law, Congress can delegate broad authority to expert administrative agencies, and courts can confidently defer to an agency's reasonable exercises of this broad authority, because of the agencies' expertise.[144] But here, because EPA is acting outside its area of expertise, a reviewing court would not defer to EPA's expert judgments,[145] and so the court would be left to its own devices in determining whether EPA's reengineering of the grid was consistent with the Section 111(d) factors.

In sum, it is highly unlikely, to say the least, that Congress would have delegated such enormous authority to an agency outside its area of expertise.

C. The Legislative History of Section 111 Confirms that Standards of Performance Are Technology-Based Emissions Limitations or Similar Measures to Be Applied at the Facilities Being Regulated.

The NSPS program was first adopted in the 1970 CAA. The structure of the program as adopted is the same as it is today. Congress directed EPA to create a list of categories of stationary sources that pose a significant health or welfare danger and to establish performance standards for those categories. The Section 111(a) definition of "standard of performance" adopted in 1970 is the same as the definition in the current statute with one exception not relevant here.[146] Section 111(d) as adopted in 1970 is identical to the provision today with the one critical amendment discussed above in Argument I. Section 111(h) remains unchanged from 1970.

Congress' intent that performance standards would be based on technology or operating systems at the facility being regulated is clear from Congress' own explicit statements to that

[144] *See Tripoli Rocketry Ass'n v. BATFE*, 437 F.3d 75, 77 (D.C. Cir. 2006).

[145] *Gonzales v. Oregon*. 546 U.S. 243, 269 (2006).

[146] In 1977, the phrase "and any nonair quality health and environmental impacts and energy requirements" was added to the Section 111(a) parenthetical.

effect. The House Report on the 1977 CAA Amendments repeatedly describes the standard as enacted in 1970 in terms similar to "best practical control technology." For instance, the House Report stated that:

> In enacting this provision [section 111], Congress was advised by the Department of Health, Education and Welfare, and understood that "the national emission standard implies *the application of * * * control technology*" to such sources. In the Congress [sic] view, it was only right that the costs of applying *best practicable control technology* be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.[147]

Congress also described the standards as "best practicable control technology," "best control technology," and "best technology requirement."[148]

As EPA points out, Congress substantively amended the definition of Section 111(a) in 1977 and then repealed those amendments in 1990. EPA argues that these changes show that the current version of Section 111(a) (and thus the version that Congress adopted in 1970) authorize the Agency to require non-technology-based standards that require significant cutbacks in a facility's production.[149]

EPA has it wrong, however. Congress amended Section 111(a) in 1977 because it concluded that the standards EPA had adopted could be met by switching to clean fuels and that the availability of clean fuels to certain parts of the country and not others was creating regional advantages that the uniform national program had been adopted to prevent.[150] Congress thus amended Section 111(a) to provide that, for new fossil-fuel-fired sources, EPA standards must (a) require a percentage reduction in emissions as compared with the emissions that would have resulted if the facility used untreated fuel and (b) reflect emissions reductions possible from the

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[147] H.R. Rep. No. 95-294, at 183-84 (1977) (1977 House Report), *reprinted in* 1977 U.S.C.C.A.N. 1077, 1262 (emphasis added).

[148] *Id*. at 186-87.

[149] EPA Legal Memo at 55-56.

[150] 1977 House Report at 186-87.

"best technological system of continuous emission reduction." But this change did not modify the basic structure of the NSPS program under which emissions standards must reflect technology or operating practices used *at the regulated facility*. It merely eliminated one potential operating practice, the use of clean fuels.[151] And, in any event, the change did not apply under Section 111(d).

Congress repealed these amendments in 1990 because Congress concluded that the amendments had only served to exacerbate regional advantages and because the provisions were no longer necessary given the national cap on emissions under the acid rain program.[152] Under Section 111(b) as it exists today, thus, facilities have the option again of using clean fuels. In any event, there is nothing in this history that contradicts Congress' underlying intent that performance standards are based on methods for controlling pollution at the source and not on forcing facilities to reduce production because EPA believes that the economy can produce substitutes.

Indeed, EPA's new interpretation undermines Congress' intent, expressed clearly in the legislative history, that the NSPS program would promote economic growth. As the D.C. Circuit has noted, the NAAQS program, adopted in 1967, is "the centerpiece" of the CAA and ensures that the level of pollutants in the ambient air does not exceed safe levels.[153] Congress was concerned, however, that the NAAQS system could "constrain economic growth" and "the NAAQS system of air quality regulation would place states with relatively cleaner air at an economic advantage, since these states could attract industry by setting less stringent emission limits."[154] As the court said, "[t]o remedy these problems created by the established system of

151 *Id.* at 187-88.
152 S. Rep. No. 101-228, at 337-38 (1989), *reprinted in* 1990 U.S.C.C.A.N. 3385, 3720-21.
153 *Sierra Club v. Costle*, 657 F.2d 298, 315, n.23 (D.C. Cir. 1981).
154 *Id*.

health-based regulation, Congress amended the CAA in 1970 to require major new sources to meet performance standards reflecting the best system of adequately demonstrated emission reduction."[155]

The NSPS program thus, from its inception, was intended by Congress to harmonize the twin goals of clean air and economic growth by requiring new sources to install the "best" systems of "adequately demonstrated" emissions controls. As the 1977 House Report stated:

> *…the use of best technology in large new pollution sources was intended to enhance the potential for long-term economic growth*. Since the national ambient air quality standards (irrespective of the policy of prevention of significant deterioration under section 101(b) created an air quality ceiling in areas cleaner than the standards, it became clear that air was a finite resource. If each large new pollution source were required to use best practicable control technology, then more new sources could locate in any given area.
>
> This in turn would permit more jobs, more production, and greater possibilities for long-term economic growth than if major new sources were not as well-controlled.[156]

Indeed, "[t]he committee has designed this section and the entire bill, to encourage and facilitate the increased use of coal …."[157]

In sum, consistent with Congress' desire to promote economic growth, the NSPS program was intended to allow for the construction of new facilities so long as they adopted modern, adequately demonstrated and affordable control technology. It was never intended, as EPA now contends, to restrict facilities from operating.

D. The Administrative History of Section 111(a) Shows that a "System of Emission Reduction" Is a System Installed or Operating at the Regulated Facility.

For the more than 40-year history of the NSPS program, EPA has consistently defined BSER as a system for reducing emissions at the regulated facility. Indeed, the label "BSER" is a

[155] *Id*.
[156] 1977 House Report at 185.
[157] S*ee* H. Rep. No. 95-294 at 192.

relatively new EPA invention. For most of the history of the program, the label for the standard that EPA adopts was "Best Demonstrated Technology," or "BDT," reflecting the common understanding that the standard was based on technology installed at the source or work practice or similar activities undertaken at the source. A chapter of a leading CAA text book discussing the NSPS program, in a section entitled "Setting the Performance Standards," describes the standards in a subsection entitled "Best Demonstrated Technology Standards." After quoting Section 111(a), the text book states that "[t]his is the BDT standard, which is yet another of the many *technology measures* found in federal pollution control statutes."[158] As the authors say, "section 111 establishes technology-based emission standards for industrial source categories…."[159] EPA's own website states that "Section 111 of the Clean Air Act authorized the EPA to develop *technology based standards* which apply to specific categories of stationary sources. These standards are referred to as New Source Performance Standards (NSPS) and are found in 40 CFR Part 60."

EPA's generic Section 111(d) regulations plainly reflect EPA's understanding that performance standards must be based on measures at the regulated facility itself. The regulations provide for EPA to issue "Emissions Guidelines" that are based on the best system of emission reduction "for designated facilities," meaning facilities within the regulated source category.[160] State plans implementing these guidelines must include "legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities."[161] Unless impracticable, these "increments of progress" "must include" all of the measures set forth in 42

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158 Julie R. Domike and Alec C. Zacaroli, THE CLEAN AIR HANDBOOK, American Bar Association Section of Environment, Energy and Resources 2001, at 328 (3d ed. 2011) (emphasis added).

159 *Id.* at 32; *see also*, Ray S. Belden, CLEAN AIR ACT: BASIC PRACTICE SERIES, at 61 (American Bar Association Section of Environment, Energy and Resources 2001.

160 40 C.F.R. § 60.21(f) and (b).

161 *Id.,* § 60.24(e)(1).

C.F.R. § 60.21(h).[162] That provision defines "increments of progress" as measures to implement technologies "which must be taken by an owner or operator of a designated facility" itself: "(1) Submittal of a final contract plan for the designated facility to the appropriate air pollution control agency; (2) Awarding of contracts for emission control systems or for process modifications, (3) Issuance of orders for the purchase of component parts to accomplish emission control or process modification; (4) Completion of on-site construction or installation or emission control equipment or process change; and Final compliance."

Other provisions of EPA's generic Section 111(d) regulations are to the same effect. The regulations require that state plans contain "test measures and procedures" for demonstrating compliance with the performance standards.[163] In certain situations, States can adopt standards that are less stringent than EPA's guidelines, including "unreasonable cost of control resulting from plant age, location, or basic process design" and "physical impossibility of installing necessary control equipment."[164] All of these provisions reflect an understanding that standards must be based on feasible and cost-effective measures taken at the regulated facility, such as pollution controls.

As is shown by reviewing any one of the numerous NSPS that EPA has established throughout the history of the program, EPA has consistently promulgated performance standards in the same way. It has designated a source category, it has examined test data or other relevant information to determine the emissions performance of various types of control technologies, it has selected performance standards, typically as a rate of emission per unit of output, based on this information, and it has required monitoring and recordkeeping to assess whether the facility

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162 *Id*.
163 *Id*. at 60.24(b)(2).
164 *Id*. at 60.24(f)(2).

meets the performance standard.[165] The same is true for the "guidelines" that EPA has issued for existing source performance standards. They are each based on technology or similar measures for "designated facilities" within the source category.[166]

It is no surprise then that EPA does not cite any precedent for defining a "system" of emission reduction as a reduction in operation of a facility in a regulated category based on EPA's conclusion that substitutes are available in the market. There is no such precedent. Indeed, EPA's current proposal is such a departure from EPA's long-established understanding of the basis for setting performance standards that the Agency, even after it proposed its Section 111(d) rule, immediately returned to its past practice in setting performance standards for oil refineries. In promulgating its refinery standards, EPA described the standards setting process as follows: "[t]he standard that the EPA develops, *based on the BSER achievable at that source*, is commonly a numerical emission limit, expressed as a performance level (*i.e.*, a rate-based standard)."[167] In other words, a standard is a maximum rate of emissions based on the performance of control systems at a source—it is not a limitation on the source's ability to operate

EPA tries to analogize three of its previous regulations (out of a 40-year regulatory history) to its current proposal, but these analogies fall flat.[168] In EPA's first example, the Agency set technology-based emissions limits for individual emitting units at waste combustion plants and allowed the owners of these plants to average NO_x emissions from each unit together to demonstrate compliance. This is obviously a far cry from EPA's proposal here, where EPA

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165 *See* EPA's NSPS regulations at 40 C.F.R. and RMB Consulting & Research, Inc., "Review and Summary of Technical Basis Used by EPA in Setting Standards of Performance for New Stationary Sources," attached hereto.
166 *See* 40 C.F.R. Subparts Cb, Cc, Cd, and Ce.
167 79 Fed. Reg. 36,880, 36,885 (June 30, 2014) (emphasis added).
168 EPA Legal Memo at 63.

has not set technology-based standards for coal EGUs and instead is requiring them to make substantial cuts in their generation.[169]

The second is EPA's Clean Air Mercury Rule (CAMR), in which EPA set technology-based limits for utility mercury emissions and permitted utilities to comply through a voluntary cap-and-trade program. [170] This example is also off point because EPA determined the nationwide ceiling in the voluntary cap-and-trade program by adding up the total mercury reductions that units would make if they each complied with EPA's technology-based standards.[171] Unlike its proposal here, EPA did not decide that utilities should cut back generation based on the notion that substitute sources of power are available. Instead, it set performance standards based on the same type of BSER analysis it has always conducted in setting performance standards (except here) and then provided flexibility in compliance.[172] CAMR may well have gone too far legally in this respect, although not nearly as far as EPA's proposal here. It was challenged in court by states and environmental groups who argued that performance standards must require every individual source to continuously comply.[173] The

169 *See* 40 C.F.R. § 60.33b(d)(1).

170 *See* "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units," 70 Fed. Reg. 28,606 (May 18, 2005). When EPA adopted CAMR in 2005, EPA amended its generic Section 111(d) regulations to change the definition of "standard of performance" to include "establishing an allowance system." 70 Fed. Reg.28,606, 28,649 (May 18, 2005) (amending 40 C.F.R. § 60.21(f)). EPA also revised the first sentence of 40 C.F.R. § 60.24(b)(1) to provide that "[e]mission standards shall either be based *on an allowance system* or prescribe allowable rates of emissions except when it is clearly impracticable." *Id.* (emphasis added). EPA further adopted a new 40 C.F.R. § 60.21(k) defining "allowance system." *Id.* In *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008), however, the United States Court of Appeals for the District of Columbia Circuit vacated CAMR. As a result, these regulatory changes became a nullity, even though.EPA did not remove these provisions from subsequent editions of the Code of Federal Regulations. Thus, EPA's regulatory definition of standard of performance as including an allowance system has no continuing legal effect.

171 70 Fed. Reg. at 28,619.

172 *Id.*

173 *See New Jersey,* 517 F.3d at 576.

court did not reach the merits of their case but otherwise vacated CAMR. Hence, CAMR is no longer an EPA regulation.[174]

EPA also cites its CAA § 129 regulations for hospital/medical/infectious waste incinerators (HMIWI)[175] and for commercial and industrial solid waste incinerators[176] under which, among other requirements, the incinerators would adopt waste management plans. These plans required examination of the possibility of removing certain types of waste from the waste stream to reduce hazardous emissions. Apart from the fact that these requirements were adopted under Section 129 rather than Section 111, they do not provide precedent for EPA's approach because they also are not based on an EPA mandate that these facilities reduce operation in order to reduce emissions. Management of fuels input is an accepted practice under the NSPS program; certain EGUs use washed coal to meet NSPS requirements and many have switched from high to low sulfur coal for the same purpose. Moreover, EPA did not in either rulemaking mandate a limitation on what wastes could be burned or the ultimate amount of emissions that these facilities were required to avoid based on their plans. For instance, in the HMIWI rulemaking, EPA stated that waste management plans "should identify, where possible, reasonably available additional waste management measures, taking into account the effectiveness of waste management measures already in place, the costs of additional measures, the emission reductions expected to be achieved, and other environmental or energy impacts they may have."[177]

In sum, EPA's proposal is unprecedented.

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174 As discussed above, CAMR changed EPA's regulatory definition of "standard of performance" to include an "allowance system," but that definition is no longer in effect.
175 62 Fed. Reg. 48,348, 48,359 (Sept. 15, 1997).
176 65 Fed. Reg. 75,338, 75,341 (Dec. 1, 2000).
177 62 Fed. Reg. at 48,359.

IV. EPA Cannot Formally Approve, and So Make Federally Enforceable, State Plan Measures that Apply to Facilities that Are Not in the Regulated Source Category, Nor Can EPA Impose a FIP Containing Such Measures.

A. EPA Cannot Approve a SIP With "Portfolio" Measures.

Under what EPA calls its "portfolio approach," state plans may contain measures that do not apply directly to facilities within the regulated source category.[178] Under this approach, state plans could include measures that either states or third parties would carry out to, for instance, generate certain amounts of renewable energy or induce the public to reduce electricity consumption. *Id.* Once EPA approves a state plan with these "portfolio" measures, the measures would become federally enforceable against the state or the third party.

EPA is mistaken. Under Section 111(d) and the Agency's regulations, EPA may not approve, and so make federally enforceable, state-plan measures that are not standards of performance applicable to facilities in the regulated source category.[179]

1. EPA lacks statutory and regulatory authority to make portfolio measures federally enforceable.

As described above, Section 111(b) provides for EPA to list categories of sources and then to establish "standards of performance for new sources *within such category*." (Emphasis added.) As also described above, Section 111(d) provides for states to submit plans which "(A) establish[] standards of performance for any existing source for any air pollutant … (ii) to which a standard of performance under this section would apply *if such existing source were a new source*." (Emphasis added.) Thus, the measures that state Section 111(d) plans must include, and which EPA can approve (or disapprove), are performance standards that apply to facilities *within the listed source category*. Contrary to EPA's contention, Congress did not give EPA

178 79 Fed. Reg. at 34,837.
179 *See* "EPA's Section 111(d) Carbon Rule: What if States Just Said No?," Federalist Society White Paper, Nov. 6, 2014, available at http://www.fed-soc.org/publications/detail/epas-section-111d-carbon-rule-what-if-states-just-said-no.

authority to approve state-plan measures that are not performance standards and that apply to third parties.

The "portfolio approach" is also inconsistent with the Agency's own regulations. EPA's general Section 111 regulations provide that performance standards apply to "the owner or operator of any stationary source which contains an affected facility" which commenced construction within the applicable time period.[180] The term "affected facility" is defined within each of the Subparts of EPA's Section 111 regulations that establish performance standards for specific categories of sources. For instance, Subpart Da defines the term "affected facility" for purposes of that Subpart as a number of subcategories of electric utility steam generating units. Subpart Da then establishes performance standards for each of these subcategories of "affected facilities." Thus, performance standards apply to facilities within the regulated source category, not to other facilities.

EPA's Section 111(d) regulations parallel this structure by providing that state plans must contain "emissions standards"[181] and that these standards "shall apply to designated facilities within the State."[182] EPA's regulations define "designated facility" as "any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that facility if the existing facility were an affected facility (see§ 60.2(e))." Thus, a "designated facility" for which state plans must establish existing-source performance standards is the same as an "affected facility" for which EPA establishes new source performance standards, except that a "designated facility" is an existing facility. Paralleling EPA's Section 111(b) regulations, the Agency's Section 111(d) regulations contain a number of Subparts, each defining the "designated facility" for which states must submit plans containing

[180] 40 C.F.R. § 60.2((b).
[181] 42 C.F.R. § 60.24(a)
[182] *Id.* at § 60.24(a)(3).

performance standards. These "designated facilities" are the facilities within the regulated source category to which the performance standards apply.[183] Thus, again, performance cannot be set for facilities in unlisted source categories.

2. EPA's justifications for making "portfolio" measures federally enforceable fail.

Although EPA is far from clear on this point, it seems to concede that "portfolio" measures are not standards of performance. It says that "[[t]he state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance—*and, for the portfolio approach, in imposing requirements on other entities*—as long as, again, the required emission performance level is met."[184] Thus, EPA does not try to justify the proposed "portfolio" measures as standards of performance and instead engages in a series of interpretational gymnastics to try to read into Section 111(d) authority for EPA to approve, and so make federally enforceable, measures that are not performance standards.

First, EPA argues that although Section 111(d) does not state that these "portfolio" measures can be included in state plans, Section 111(d) does not say that they can't.[185] EPA maintains that this creates a "gap" that EPA can fill under *Chevron* step two.[186] But as the D.C. Circuit has previously instructed EPA, agencies only have the power Congress gives them, and

183 *See, e.g.,* 40 C.F.R. Subpart Cd defining "designated facilities" for purposes of that subpart as sulfuric acid production units. Nothing in these regulations authorizes EPA to approve non-performance standards measures. To accomplish its intended result, EPA has proposes a new regulatory vocabulary that applies only "in this subpart." *See* proposed 40 C.F.R. § 60.5820. Thus, instead of requiring states to submit plans containing emission standards for "designated facilities," EPA requires state plans that set forth emissions standards for each "affected entity." "Affected entity" is not a term that EPA has previously used in its Section 111(d) regulations and is defined in the Agency's proposed regulations as "any of the following: An affected EGU, or another entity with obligations of this subpart for the purpose of meeting the emissions performance goal requirements in these emissions guidelines." *See* proposed 40 C.F.R. § 60.5789. EPA also proposes to expand the definition of the term "emission standard" as set forth in its current regulations to mean "in addition to the definition in § 60.21, any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, including, for example, renewable energy and demand-side energy efficiency measures requirements."

184 79 Fed. Reg. at 34,853 (emphasis added).

185 *Id.* at 39,402.

186 *Id.*

so EPA cannot transform Congressional silence into an implied Congressional authorization.[187]There is thus no "gap" in the language of Section 111 that EPA can fill in order to create authority to approve "portfolio" measures.

EPA next maintains that it can approve and make federally enforceable non-performance-standard measures in state Section 111(d) plans because, under CAA § 110, states have discretion to include various types of measures in their SIPs to attain NAAQS.[188] As discussed above, however, the NAAQS program is fundamentally different from the NSPS program. EPA's role in the NAAQS program is to set the applicable standards and to judge whether state plans contain measures that will attain and maintain those standards.[189]Congress specifically gave states the authority to formulate any measures they wish to meet those standards.[190] Under Section 111(d), in contrast, state plans must include "standards of performance," which is a defined term having a specific regulatory context. No CAA authority exists for Section 111(d) plans to contain other types of federally enforceable substantive measures.

EPA moves on to an even more far-fetched justification for the "portfolio" approach by claiming that measures applicable to facilities outside the regulated source category are measures that "implement[]" standards of performance under Section 111(d)(1)(b).[191] But EPA takes the term "implement[]"out of context. The "implementation and enforcement" measures that States must include in their Section 111(d)(1)(b) are measures that implement and enforce the state-established standard of performance. To implement and enforce a standard of performance, the state must establish compliance schedules for the designated facilities, it must adopt monitoring

[187] *Michigan v. EPA*, 268 F.3d 1075, 1081-1082 (D.C. Cir. 2001) ("Agency authority may not be lightly presumed. 'Were courts to presume a delegation of power absent an express withholding of such power, agencies would enjoy virtually limitless hegemony, a result plainly out of keeping with Chevron and quite likely with the Constitution as well,'" quoting *Ethyl Corp. v. EPA*, 51 F.3d 1053, 1060 (D.C. Cir. 1995)).
[188] *Id.* at 34,879.
[189] *Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 79 (1975).
[190] *Id. See also Commonwealth of Virginia v. EPA*, 108 F.3d 1397 (D.C. Cir. 1997).
[191] EPA Legal Memo at 79.

and reporting requirements, and it must have legal authority to adopt and mechanisms in place to enforce the standard.[192] Implementing a performance standard, however, obviously does not mean adopting an entirely different type of standard applicable to and enforceable against a facility that is not even subject to the standard of performance itself.

EPA lastly engages in truly convoluted statutory construction based on the word "for" in the following language of Section 111(d): "The Administrator shall prescribe regulations … under which each State shall submit to the Administrator a plan which (A) establishes standards of performance *for* any existing source …." (Emphasis added.) EPA, with evident seriousness, maintains that "portfolio" measures that require sources outside the regulated category to take specific actions are measures "for" sources within the regulated source category because the "portfolio" measure will indirectly result in reduced production and therefore emissions within the regulated category.[193] EPA is not clear whether, under this approach, the "portfolio" measures would be considered to be standards of performance. Presumably, they would be since EPA tries to justify these measures as "standards of performance *for* any existing source" (meaning an existing source within the regulated category) (emphasis added). But in the first full paragraph of page 34,903, EPA signals that, under this justification, portfolio measures would *not* be considered to be standards of performance. As EPA states, "[t]o the extent that a portfolio approach contains measures that are not standards of performance or do not implement or enforce such standards, the EPA is proposing to interpret CAA section 111 as allowing state CAA section 111(d) plans to include measures that are neither standards nor measures that

192 *See* 40 C.F.R. §§ 60.24-60.26.
193 79 Fed. Reg. at 34,903.

implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources."[194]

EPA's confusion as to whether "portfolio" measures might or might not be construed to be performance standards is understandable given the tortuous reading that it gives the term "for." However, either the measures contained within the "portfolio" approach are (a) standards of performance or measures to implement or enforce those standards, in which case they can be included in a state plan, or (b) they are not, in which case they can't. Here, as even EPA appears to concede, the measures are not standards of performance. Hence, they cannot be included in state plans. In any event, there is no possible reading of the term "for" in the context in which it is used in Section 111(d) that could convert a standard which a facility in a nonlisted source category must meet into a standard that applies to—and is therefore "for"—facilities in a listed source category.[195]

B. EPA Cannot Impose a Federal Plan Containing "Portfolio" Measures.

It is unclear from EPA's proposal whether the Agency believes it could impose "portfolio" measures in a federal plan. The Agency assuredly cannot impose such measures, for the same reasons just discussed as to why it cannot approve a state plan containing such measures. Like a state plan, the EPA plan must contain valid standards of performance and measures to implement and enforce those measures. It cannot contain other measures.

[194] 79 Fed. Reg. at 34,903.

[195] Of course, states are free to adopt any plans they want to reduce emissions consistent with state law. But what EPA cannot do, as it has proposed to do here, is to approve and make federally enforceable measures that are neither standards of performance nor measures to implement or enforce standards of performance.

V. EPA Cannot Combine the Coal and Natural Gas EGU Source Categories for the Purpose of Setting Performance Standards.

A. Background.

In EPA's original Section 111(b) proposal for coal- and natural-gas fueled EGUs, EPA proposed to combine the Subpart Da (coal) and Subpart KKKK (natural gas) categories into a single Subpart TTTT category for the purpose of establishing CO_2 performance standards for new sources.[196] EPA did so because, in reality, EPA was not proposing CO_2 performance standards for coal units at all. EPA's combination of the source categories was a transparent ploy to prevent the construction of new coal plants by proposing standards that only natural gas generators could meet.

NMA and other commenters showed in their comments that EPA could not, consistent with Section 111, combine the two categories for the purpose of establishing performance standards that only natural gas units could meet.[197] NMA and others also showed that, if EPA established a new source category, it must make a Section 111(b) "significant contribution" finding, which EPA had not done. *Id.* at 47-64.

When EPA reproposed these regulations in January of this year, EPA made separate co-proposals, one in which EPA proposed to keep the separate Da and KKKK categories and another in which EPA would combine the categories into a single TTTT category.[198] EPA said that there was no substantive difference between the two co-proposals because, even if EPA adopted the latter proposal, it would create separate sub-categories for coal and natural gas units

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[196] *See* "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units."

[197] *See* NMA comments in Docket ID No. EPA-HQ-OAR-2011-0660, June 25, 2012 (NMA Comments) (attached hereto), at 64-92.

[198] "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 1,430, 1,454 (Jan. 8, 2014).

with separate performance standards for each.[199] According to EPA, because the TTTT category would only be for administrative convenience, establishing this new category would not require a "significant contribution" finding.[200]

EPA's real reason for proposing the new category TTTT in its January proposal, however, was not administrative convenience. EPA did so as a predicate for its current Section 111(d) proposal, because it believed that it needed to combine the source categories under Section 111(d) in order to adopt the broad definition of BSER it has now proposed. EPA was concerned that it could not combine the source categories for purposes of Section 111(d) regulations unless it had first combined the categories for purposes of Section 111(b) regulation. As EPA stated, "…we seek comment on whether the co-proposal to combine the source categories and codify the GHG standards for all new sources in subpart TTTT will offer any flexibilities for any future emission guidelines for existing sources, *for example, by facilitating a system-wide approach* …."[201]

EPA has now carried that approach forward into its Section 111(d) regulations by proposing a new source category UUUU that combines the Da and KKKK categories for the purpose of establishing CO_2 performance standards for existing units.[202] EPA believes that combining the two source categories will advance the current regulation in two respects, both related to its concern that building blocks three and four are legally vulnerable. First, EPA asks for comment on an alternative building-block-one-and-two-only approach, an approach it presumably may adopt in its final regulation if it becomes convinced that building blocks three

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199 *Id.* at n. 99 & 100.

200 *Id.* at 1,454. In the alternative, EPA proposed to make an abbreviated "significant contribution" finding that ignored the statutory contribution standard and instead substituted an agency-supplied rational basis standard. *Id.* at 1,455-56.

201 79 Fed. Reg. at 1,454 (emphasis added).

202 *Id*. at 34,855.

and four will not pass legal muster.[203] EPA also contemplates that it can fall back on a building-block-one-and-two-only approach if it adopts a four-building-block regulation and the latter two building blocks are overturned in court. EPA thus proposes that a building-block-one-and-two-only approach would be "severable" from the underlying rule and would therefore survive judicial invalidation of the third and fourth building blocks.[204]

EPA's attempt to preserve a building-block-one-and-two-only option, however, depends on the agency's ability to combine the coal and gas categories. EPA does not want to regulate natural gas units in a separate category from coal units because EPA wants to *increase* natural gas generation, not *reduce* it. Nor does EPA want to regulate coal units in a separate source category because an "inside-the-coal-unit-fence" approach would not yield sufficient emission reductions. Hence, to achieve EPA's goals, it must combine coal and natural gas into a single source category. But EPA cannot do so.

B. EPA's Proposal to Combine the Two Categories Is Inconsistent with Section 111.

EPA's combination of the coal and natural gas categories into a single category is unlawful for the same reason that EPA's proposal to do the same in its new source regulations is unlawful. As NMA showed in its comments on EPA's first new source proposal, the statute commands EPA to separate stationary sources into source categories for the purpose of promulgating common performance standards for facilities within each category.[205] This has been EPA's consistent past practice.[206] As a result, because coal and natural gas plants are fundamentally different types of electric generation technologies that lend themselves to different types of emission reduction systems, EPA has always separated coal and gas units into

203 *Id*. at 34,878; *see also* discussion at 34,882-83.
204 *Id.* at 34,892.
205 *See* NMA New Source Comments at 80-92.
206 *Id.*

separate categories, now collected in categories Da and KKKK, and set different emission-reduction standards for each category (including subcategories). Indeed, just two years ago, in adopting its Mercury and Air Toxics Standards, EPA revised the standards for categories Da and KKKK and determined not to combine the two categories. EPA deemed it inappropriate under Section 111 to create a single coal/gas category because there is no technology that would allow coal to meet a standard based on the capabilities of a gas plant. As EPA correctly explained then:

> basing these [coal-fired EGU] standards on [natural gas or distillate oil] would result in standards that are neither technically nor economically achievable for coal-fired EGUs. Basing the amended standards on the use of natural gas would preclude the development of new coal-fired EGUs since the standards would not be technically achievable…Therefore, basing the NSPS on [natural gas] emissions would not be achievable for coal-fired EGUs with any technology that EPA is aware of.[207]

But this is exactly the result that EPA—purposefully—will achieve in combining the two source categories for the purpose of establishing Section 111(d) performance standards for CO_2 emissions; coal utilization will be substantially reduced, numerous coal plants will be forced to retire, and natural gas utilization will increase. EPA does not attempt in the current rulemaking to explain its reason for departing from its consistent past interpretation,[208] most recently in the MATS rulemaking, and for good reason—because EPA's reason for combining the categories is illegitimate. EPA is dissatisfied with the amount of emission reduction coal plants would be required to make through application of the statutory BSER factors to those plants. It therefore needs to create a regulatory system that mandates increased generation from natural gas plants in order to justify the dramatic reduction in coal-based generation that the Agency wants. It thus

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[207] EPA, Mercury and Air Toxics Rule, Docket N0. EPA-HQ-OAR-2009-0234, Response to Public Comments on Rule Amendments Proposed May 3, 2011, sec. 2 at 1-2 (Dec. 2011).

[208] *See West Deptford Energy, LLC v. FERC,* 766 F. 3d 10 (D.C. Cir 2014 (agency may not depart from consistent past practice without an adequate explanation). NMA's attached comments on EPA's first new source proposal further describes EPA's consistent past practice in separating coal and gas plants into separate categories and the reason why EPA's combination of these two categories is legally invalid.

proposes to combine the coal and natural gas categories into a single category so that, as it proposed to do in its first and now-withdrawn new source proposal, it can set a standard that only the gas plants can meet. But EPA does not have authority to combine the source categories in order to create standards that a category of sources cannot meet.[209] Nor, as explained above, can EPA create performance standards that require a regulated category of source—here NGCC units—to operate and therefore emit *more*.

EPA professes that it is proposing to create a single source category here "because the emission guidelines the EPA is establishing do not vary by the type of source."[210] But that is precisely the problem. Because the common "guidelines" for coal and gas plants are no more than a subterfuge for improperly driving down coal generation, EPA's proposal to combine the coal and natural gas categories is unlawful.

C. EPA's Combination of the Da and KKKK Categories Suffers from Two Additional Flaws.

Although EPA's combination of the two source categories is irremediably flawed for the substantive reason just discussed, two process flaws are worth noting. First, under Section 111(d), EPA cannot require states to submit plans containing performance standards for sources in categories that EPA has not established under Section 111(b). Thus, even assuming EPA has authority to combine the coal and natural gas categories, EPA cannot establish the UUUU category for existing sources unless it establishes the TTTT category for existing sources. This is because, under Section 111(d), EPA can require states to submit plans establishing performance standards only for "any existing source for any air pollutant … to which a standard of performance under this section would apply if such existing source were a new source." EPA's Section 111(d) regulations thus must parallel its Section 111(b) regulations: EPA must

209 *See* NMA New Source Comments at 64-92.
210 79 Fed. Reg. at 34,855.

first establish source categories and set performance standards for new facilities within those categories, and then it can call on states to submit plans in which states establish performance standards for sources within those categories. EPA is therefore not free to establish a new category of facilities for purposes of Section 111(d) regulation that does not exist for purposes of Section 111(b) regulation.[211]

Second, if EPA does establish the new TTTT category in its new source rulemaking and the parallel UUUU category here, it must make a "significant contribution" finding under Section 111(b), as NMA showed in its previous comments. It cannot simultaneously maintain that it has a substantive need to create a new category (here, the need to establish a CO_2 regulatory program), while at the same time failing to fulfill the statutory condition precedent (the making of a "significant contribution" finding) for the creation of a new source category.[212]

VI. EPA Lacks Authority to Adopt Its Proposal Because It Has Not Adopted Corresponding Section 111(b) Standards.

As EPA recognizes, it cannot adopt Section 111(d) regulations for a source category unless it has first adopted corresponding regulations for that source category under Section 111(b).[213] EPA has not done so here. As set forth in NMA's comments on EPA's new source proposal, the new source standard EPA has proposed for coal EGUs has not been adequately demonstrated and is not achievable by regulated sources. EPA therefore has not proposed a valid coal EGU performance standard and, as a result, if EPA finalizes that proposal, EPA will not

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211 Of course, EPA can codify its existing source regulations for a particular category into a different subpart than it has codified its new source regulations for the same category. Such differences in codification truly are solely for administrative convenience. Thus, EPA could (in theory, absent the fundamental substantive issue identified above) establish the TTTT category for new sources and the UUUU category for existing sources so long as the categories were substantively the same.

212 *See* NMA New Source Comments, June 25, 2012, at 47-64.

213 *See* Section 111(d)(1)(A)(ii) (Section 111(d) standards apply to air pollutants emitted by source categories "to which a standard of performance under this section would apply if such existing source were a new source").

have promulgated valid Section 111(b) standards that could serve as the basis for Section 111(d) standards.

EPA is aware that its Section 111(b) proposal is on shaky legal grounds, and so has taken the position that its proposed performance standards for modified and reconstructed coal EGUs could independently provide the basis for proceeding with its Section 111(d) regulations. EPA's view is that because Section 111(a)(2) defines "new" sources to include "modifications," its modified/reconstructed source rule can support its existing source regulations.[214]

EPA has once again ventured into new interpretational territory, as the Agency cites no precedent for separating its "new" source standards into two separate rulemakings—one for new sources and another for modified/reconstructed source—with either one of them sufficient for supporting existing source standards. Regardless, EPA's approach doesn't work. In the first place, as shown in NMA's comments on EPA's proposal to set performance standards for modified and reconstructed coal units,[215] EPA states that modified and reconstructed sources will be treated as *existing sources* that remain subject to any § 111(d) standard that is then in effect. EPA states:

> [A]ll existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b).[216]

EPA, however, cannot simultaneously treat modified and reconstructed units as existing sources under Section 111(d) and as new sources under Section 111(b).

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[214] 79 Fed. Reg. at 34,852.

[215] *See* Comments of the National Mining Association on "Proposed Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units," Docket ID No. EPA-HQ-OAR-2013-0603 (October 15, 2014) (attached hereto).

[216] 79 Fed. Reg. 39,463 (June 18, 2014).

Moreover, the source categories EPA is regulating under its proposed modified/reconstructed source rule and its proposed existing source rule are different. Under the proposed modified/reconstructed source rule, EPA is regulating coal EGUs. As discussed above, under the proposed existing source rule, EPA is nominally regulating a combined coal/natural gas category but in reality is setting standards applicable to entire state utility systems. Because Section 111(b) and Section 111(d) regulations must apply to the same source category, EPA cannot rely on its modified/reconstructed source regulations to regulate existing coal EGUs,

VII. The Proposed Rules Are Ultra Vires Because Congress Did Not Delegate Authority to the Agency to Regulate the Electric Grid.

The Federal Power Act grants authority to FERC to regulate the interstate sale and transmission of electricity,[217] while recognizing states' inherent police power to regulate the planning and development of electric generation and the provision of electricity to the public.[218] EPA's proposal manages to intrude into both state and FERC electric regulatory authority.

A. EPA's Proposal Encroaches on State Authority Over Electric Generation Planning and Development.

Under the Tenth Amendment, the federal government has only such powers as are enumerated in the Constitution; all other powers are reserved to the states. As a result, states, not the federal government, are the repository of the general police power to protect the public.[219] Among the police powers of the state is the regulation of public utilities. [220]

Of course, Congress has power under the Commerce Clause to regulate interstate commerce and did so regarding the interstate electric market first in the Federal Water Power

[217] 16 U.S.C. § 824(b)(1).
[218] *Id*., § 824(a).
[219] *See, e.g.,* John E. Nowack & Ronald D. Rotunda, CONSTITUTIONAL LAW 138 (7th ed., 2004).
[220] *Munn v. Illionis*, 94 U.S. 113, 124 (1877); *see also* Richard J. Pierce, Jr. and Ernest Gellhorn, REGULATED INDUSTRIES IN A NUTSHELL 78-83 (1999).

Act of 1920 and then in the Federal Power Act of 1935 (FPA), as amended.[221] But while Congress gave the Federal Power Commission, now FERC, authority over interstate electric transactions, this power "extend[s] only to those matters … not subject to regulation by the States."[222] Thus, FERC has jurisdiction over wholesale electric sales but lacks power to interfere with "state authority in such traditional areas as the authority over … administration of integrated resource planning and … utility generation and resource portfolios."[223] Thus, as Congress divided state and federal power, "the States retain their traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related concerns."[224]

When Congress explicitly reserves jurisdiction over a matter, "[t]hat places the matter off-limits to the FERC," which "has no business" attempting to regulate it.[225] Thus, for instance, while FERC may establish policies to encourage the development of new electric capacity, it may not mandate the type of resources that states may develop in response.[226] States thus have plenary authority to shape their generation portfolios, including "the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from [FERC]."[227] This

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221 16 U.S.C. § 791a, *et seq.*.

222 16 U.S.C. § 824(a); *see also New England Power Generators Ass'n v. FERC*, 757 F.3d 283, 290 (D.C. Cir. 2014).

223 *New York v. FERC*, 535 U.S. 1, 24 (citing FERC Order No. 888, FERC STATS. & REGS. PREAMBLES, Jan. 1991-June 1996, 31,782, n. 544; *Ameren Energy Mktg. Co*., 96 FERC ¶61,306, 62,189 (2002) ("whether a purchaser has prudently chosen from among available supply options … is generally a question that the state commissions address.").

224 *Pacific Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983).

225 *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996).

226 *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 479 (D.C. Cir. 2008).

227 *Connecticut DPUC v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

"other action" that states may take, of course, could include determining resource portfolios that might not favor the selection of higher cost resources over lower cost resources.

Thus, the dividing line between state and federal authority in regulating electricity has always been considered to be a "bright" one,[228] with authority over electric generating planning and development falling comfortably on the state side of the line. States have traditionally exercised their plenary power in this area through public service commissions.[229] Most state commissions superintend electric utility generation resource planning by requiring utilities to file Integrated Resource Plans (IRPs).[230] The purpose of an IRP is to enable utilities, through a public process, to develop long-term plans for matching electric demand with a portfolio of supply and demand-side resources that the state commission determines are compatible with the public interest. *Id.* The IRP planning process can vary from state-to-state, as can the results of that process, depending on the specific circumstances of each state and the relative weight individual state commissions assign to the relevant public policy factors. *Id.*

EPA's proposal exceeds the Agency's authority by impinging on this well-established and longstanding state police power over electric generation planning and development. Indeed, EPA's proposal seeks to displace state planning authority almost entirely by establishing mandatory state goals based on EPA's own version of what state IRP should look like rather than the IRP that state commissions have adopted. As discussed above, EPA has developed what it considers to be the "best" electric utility system for each state comprised of what EPA thinks it's the best electric resource mix for each state. Thus, for each state, EPA has determined each state's 2012 resource mix and then, on a state-by-state basis, determined how much the state

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228 *FPC v. Southern Cal. Edison Co.*, 376 U.S. 295, 215-16 (1964).
229 *See* National Association of Regulatory Commissioners website, http://www.naruc.org/Commissions/, listing commissions for all 50 states.
230 *See* Rachel Wilson and Bruce Biewald, BEST PRACTICES IN ELECTRIC UTILITY INTEGRATED RESOURCE PLANNING, Regulatory Assistance Project, June 2013, available at *www.raponline.org/document/download/id/6608*.

should reduce coal generation and how much it should increase the use of other resources.[231] Under the authorities cited above, however, not even FERC, much less EPA, has the authority to dictate resource outcomes to the states. As the Kansas Corporation Commission aptly put it:

> Of particular concern is the extent of the EPA's proposed regulatory reach into Kansas' mix of energy resources. The KCC-regulated electric utilities in Kansas are vertically integrated investor-owned public utilities subject to traditional rate of return economic regulation under which the KCC carefully balances the interests of the public utility against those of the public the utility serves. In its proposed Clean Power Plan, the EPA has inserted itself into a regulatory field occupied by the states for decades in which the states have proven expertise in public utility ratemaking and in understanding the complexity of the electric grid and electric reliability. The proposed rule will disrupt the carefully balanced, cost-effective delivery of electricity in Kansas and will lead to detrimental effects, both within the Kansas economy and with the states with which Kansas does business.[232]

EPA's intrusion into an area that the Constitution and Congress reserved for states cannot be justified by the notion that EPA's proposal gives states "flexibility" to adopt whatever plan they want (one that by definition would be less than what EPA considers to be the "best" plan) to meet the EPA-mandated carbon intensity goals. As EPA recognizes, EPA intrudes on traditional state public service authority simply by approving a state plan that contains renewable and demand-side measures, thus making these measures enforceable by EPA. As EPA says, "including [renewable energy ("RE")] and demand-side [energy efficiency ("EE")] measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate."[233]

More fundamentally, however, the alleged "flexibilities" are chimerical given the stringency of the goals and the extreme nature of the assumptions underlying those goals. For a

[231] *See* spreadsheet at state-goal-data-computation spreadsheet supporting GHG Abatement Measures TSD.
[232] Comments on the proposed rule of the Kansas Corporation Commission.
[233] 79 Fed. Reg. at 34,902.

state to generate more coal-fired electricity than in EPA's best plan for that state, the state would have to significantly increase its use of some other resource—either lower (at the point of generation) CO_2-emitting resources such as natural gas, non-CO_2-emitting resources or demand-side resources—to compensate for the increased CO_2 emissions. But, as previously explained, EPA has already assumed that all existing natural gas generation will operate at levels achieved by only 10% of existing gas generators in 2012 and that renewable resources and demand-side resources will be developed at unprecedented rates. EPA not only assumes that all under-construction nuclear will come on line as planned, it assumes that all at-risk nuclear will not retire. It also assumes that existing nuclear will continue to operate at maximum feasible capacity factors. There is thus little "flexibility" to depart from EPA's "best" plan, and whatever "flexibility" there might be is all biased towards state adoption of truly draconian measures.

In sum, EPA's proposal would preempt the states' fundamental police power over electric generation by dictating—or at least severely constraining—state electric generation resource decisions. But the notion that Congress, even if it had constitutional authority to intrude on state control of this area, withheld this authority from FERC—the nation's electric regulator—but granted it to EPA is absurd. And the notion that Congress took this momentous action through Section 111(d), without giving any indication that it was even aware it was doing so, shreds the fabric of credulity. To quote the Supreme Court again,

> *EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization.* When an agency claims to discover in a long-extant statute an unheralded power to regulate a 'significant portion of the American economy … we typically greet the announcement with a measure of skepticism.[234]

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[234] *Utility Air Regulatory Group,* 134 S. Ct. at 2444 (emphasis added).

B. EPA's Proposal Encroaches on FERC Authority Over Interstate Electric Markets.

EPA's proposal not only improperly dictates state electric resource portfolio decisions, it impinges on authority Congress gave FERC over wholesale electric transactions. Plainly, EPA cannot regulate in an area that Congress reserved for FERC.[235]

FERC has broad authority under 16 U.S.C. § 824(b)(1) to set rates and terms of service for selling electricity at wholesale.[236] All FERC-regulated utilities[237] must have a FERC-approved tariff to sell electricity—either a market-based tariff for those utilities that FERC has deemed not to have market power or a cost-of-service tariff for a small number of utilities selling in areas where they do have market power. In addition, a number of regions of the United States (covering about two-thirds of the nation's population) have formed Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). These entities, through FERC-approved tariffs, operate organized regional power markets in which power is sold through what are essentially day-ahead and two-day-ahead auctions. Power is sold in the rest of the country through bilateral contracts under utilities' FERC-approved tariffs. Power is also traded throughout the country at regional hubs, again subject to FERC control.[238]

In virtually all of the United States, power is transmitted through an interstate grid that is also pervasively regulated by FERC. All utilities owning transmission have been required to file Open Access Transmission Tariffs guaranteeing non-discriminatory access by generators to

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[235] *Cf. Brian Hunter v. FERC*, 711 F.3d 155, 156 (D.C. Cir. 2013) (FERC cannot intrude on Congressionally-delegated jurisdiction of the CFTC).

[236] *New York,* 535 U.S. at 55-56.

[237] FERC does not have jurisdiction over sales by public power and cooperatively-owned utilities.

[238] *See* FERC, ENERGY PRIMER, A HANDBOOK OF ENERGY MARKET BASICS, available on FERC website at http://www.ferc.gov/market-oversight/guide/guide.asp.

transmission. RTOs and ISOs also operate the regional grids in their areas through FERC-approved tariffs.[239]

As noted by the Department of Energy (DOE) in a report to Congress, electricity in both organized and traditional regional markets is dispatched to serve load through the principle of "economic dispatch."[240] Congress in Section 1234 of the 2005 Energy Policy Act defined economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." Congress expressed a strong policy preference for economic dispatch by authorizing DOE to conduct a study of the procedures currently used by electric utilities to perform economic dispatch, to identify possible revisions of those procedures to improve the ability of non-utility generation to offer their inclusion in economic dispatch, and to analyze the potential benefits of such inclusion.[241] The DOE report concluded that "[e]conomic dispatch benefits electricity users in a number of ways. By systematically seeking the lower cost of energy production consistent with electricity demand, economic dispatch reduces total electricity costs." Report at 4.

Dissatisfied with the results that FERC regulation has produced, however, EPA now wishes to make itself the master of the interstate grid by replacing the principle of economic dispatch with the principle of environmental dispatch. As EPA states, "[o]verall, the BSER proposed here is based on a range of measures that fall into four main categories [including] dispatching lower-emitting EGUs and zero-emitting energy sources…."[242] EPA frankly calls its

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239 *Id.*

240 Department of Energy, THE VALUE OF ECONOMIC DISPATCH, A REPORT TO CONGRESS PURSUANT TO SECTION 1234 OF THE ENERGY POLICY ACT OF 2005, Nov. 7, 2005, at 4, available at http://energy.gov/oe/downloads/value-economic-dispatch-report-congress-pursuant-section-1234-energy-policy-act-2005. *See also* FERC, ENERGY PRIMER at 42.

241 *Id.*

242 79 Fed. Reg. at 34,835.

second building block the "EGU CO_2 emissions reductions achievable through redispatch from affected steam EGUs to affected NGCC units."[243] Indeed, EPA's GHG Abatement Measures TSD devotes an entire chapter, entitled "CO2 Reduction Potential from Re-Dispatch of Existing Units," to a discussion of how the grid is presently dispatched according to economic dispatch principles and how EPA could glom on to this interstate system and force its "redispatch" to achieve EPA's CO_2–emission reduction goals.[244]

However, nowhere in the TSD or in the proposed rule does EPA discuss how it could possibly have authority, either directly or indirectly, to "redispatch" the power grid. Congress gave FERC, not EPA, control over interstate sales of electricity. EPA does not even identify a mechanism under which it could attempt to mandate "redispatch." Certainly, any "redispatch" mechanism that EPA developed would require FERC approval either through a utility tariff or the tariff of an ISO or RTO. But EPA's proposed rule does not provide for that type of approval. EPA appears to think that it has co-equal or even superior authority over the grid as compared with FERC and, that by mandating the adoption of state plans, it can force the grid to operate the way it wants. But Congress gave jurisdiction over interstate electric transactions to FERC, not EPA.[245]

VIII. EPA's BSER Building Block Analysis Is Riddled with Flawed and Arbitrary Assumptions.

NMA has shown above that EPA's BSER analysis is conceptually flawed because it improperly considers measures that apply to facilities that are not within the regulated source category. However, even if a BSER analysis could include those measures, the analysis that EPA conducted was fundamentally arbitrary. The BSER that EPA has formulated for each state

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243 *Id.* at 34,857.

244 GHG Abatement Measures TSD, Ch. 3.

245 *Cf. Chao v. Cmty. Trust Co.*, 474 F.3d 75, 82 (3d Cir. 2007) ("It is axiomatic that the executive branch may not do indirectly what Congress has forbidden it to do directly….").

is not only not the "best" system that has been "adequately demonstrated," it is not a system that has been "adequately demonstrated" at all. As a result, the "degree of emission limitation" that EPA is requiring based on its BSER analysis is not "achievable."

A. EPA's "Best" System for Reducing Emissions Is Based on a Flawed Understanding of How the Grid Works.

Ironically, given that EPA has justified its broad "system" approach to BSER by referring to the interconnected nature of the grid,[246] EPA's building block analysis is premised on the notion that the grid can be disaggregated into fifty separate mini-grids that follow states borders. Thus, EPA examines each state's generation resource mix and the amount of emissions those resources produce, and then establishes individual state goals based on how each state can change its resource mix to make the desired amount of emission reductions. No consideration is given to the fact that both the nature of a state's generation mix and how much of that generation operates at any particular time is directly affected by the interconnectedness of the state's generation with other states' generation. At any particular time, resources within a state may be operating more or less depending on factors affecting supply, demand and operating conditions in a broad multi-state regional market. As stated by FERC Chair LaFleur:

> The Clean Air Act does things by state-by-state state implementation plans. That's how the Clean Power Plan draft last June is set up. The power markets, of course, do not operate state-by-state. So, I think there will be very considerable— potentially— implications for the operation of the markets as the states make all their implementation decisions.[247]

EPA's approach therefore is not based on the operation of the grid as it exists in the real world. At the least, trying to superimpose individual state goals derived from EPA's imagined 50 "best systems" onto the actual real-world system will create significant inefficiencies and

[246] 79 Fed. Reg. at 34,843-44, 845.
[247] FERC Commissioners Split Over NERC's Role In ESPS Reliability Debate, InsideEPA.com, September 12, 2014.

perverse incentives. These systems thus cannot be described as "best." Other commenters will address this issue more deeply. NMA points out two glaring flaws in EPA's analysis below.

1. EPA's BSER contains two irreconcilable logical conundrums.

By asserting simultaneously that it has devised the "best system" for reducing emissions but that states have the "flexibility" to depart from that system so long as they meet EPA's state-by-state goals, EPA creates two logical conundrums. First, EPA's claim that it has devised the best system of emission reduction for each state is belied by the model it ran to simulate how the grid will operate if EPA's goals are superimposed on it. The model results show that states compliance strategies deviate significantly from the "best" system EPA has devised. Either EPA's model is wrong, because it is not selecting the best system for reducing emissions, or EPA's "best systems" are not "best" at all, because the model is rejecting them. EPA cannot have it both ways.

Second, as a part of the supposed "flexibility" EPA is granting states, a state could propose to meet its goal by (a) exceeding the level of performance for a given building block or substituting an alternative and (b) making corresponding changes to the level of stringency of the other building blocks. But, in theory, the fact that a state determines that it can do better than EPA's assumed stringency for one building block does not mean that a state cannot obtain the level of stringency EPA has set for the other building blocks. Thus, the notion of state implementation flexibility is fundamentally at odds with EPA's building block methodology. Having chosen to determine the "best" amount of emission reduction each state should obtain for each building block, EPA has no logical basis to say that what really matters is the overall goal, not the building blocks.

2. Electricity sources do not substitute for each other.

EPA bases its proposal on the supposition that utilities "treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions."[248] As a result, EPA designs its state "best systems" and calculates the state goals as if increasing natural gas generation can automatically displace coal power, and increasing nuclear and renewable power can automatically displace coal and natural gas power.[249]

But this premise is demonstrably false; grid operations are considerably more complicated. Coal and nuclear units operate best when operated as base load units because they cannot cycle up and down quickly. Coal and nuclear units also perform important grid-stability functions that other resources cannot perform, as discussed further below. Although NGCC units can operate in base load mode, they have traditionally operated as intermediate units, cycling to follow load because they can ramp up and down quickly. Simple cycle natural gas units typically run as peaking units. Wind and solar units operate intermittently as the wind blows and the sun shines. These resources must be backed up with natural gas units to ensure that the grid remains in balance as wind and solar power fluctuate.

Indeed, one of the great fallacies of the rule is that it would reverse the traditional functions of NGCC and coal units. Despite their ability to cycle up and down quickly, natural gas units would increasingly be relied on to serve a baseload function. And despite the inability of coal units to cycle up and down quickly, coal units would be forced to cease operating as baseload units and would instead be called on to operate intermittently. The Electric Power

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[248] 79 Fed. Reg. at 34,845.
[249] *See* Data File: Goal Computation (Appendix 1 and 2).

Research Institute (EPRI) thus expresses "concern[] that today's coal fleet may not be able to provide adequate flexible operations capabilities for the overall fleet as most existing coal plants were not originally designed for such duty."[250] NERC made the same point:

> "Grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs, needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.
>
> A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.[251]

Wind units pose particular challenges for the grid because the wind tends to blow less when the weather is the hottest or the coldest and therefore when electric demand is the highest. The availability of wind can fall quickly. For instance, on one day in Texas, wind generation dropped by 93% (a total loss of 6,500 MW) over 13.5 hours. [252] On another day, wind generation dropped by 3,430 MW in 10.8 hours.[253] As a result, although wind resources can

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250 EPRI, "Comments of the Electric Power Research Institute On EPA's Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units [CAA § 111 (d)]" (EPRI Comments), October 29, 2014, at 16, available at http://www.epri.com/Pages/EPRI-Comments-On-Proposed-Clean-Power-Plan.aspx.

251 NERC, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan" (NERC Report) at 13 (footnote omitted) (attached hereto).

252 Testimony before the Energy and Power Subcommittee of the House Energy and Commerce Committee of Texas Public Utility Commissioner Kenneth W. Anderson, Jr. (Anderson Testimony), September 9, 2014, at 8-9, available at http://energycommerce.house.gov/hearing/state-perspectives-questions-concerning-epa%E2%80%99s-proposed-clean-power-plan.

253 *Id.*

have annual capacity factors of 40 percent or even more in some areas, these resources are assigned much smaller capacity factors in determining their contribution to generation reserves available to meet system peaks. MISO, for example, assigns wind a system-wide capacity credit of only 14.1%.[254] Fossil and nuclear resources, in contrast, can be counted on to operate reliably year round.[255]

For this reason, the Kansas Corporation Commission has expressed concern that EPA's "best system of emission reduction" for the states would impair grid reliability:

> The EPA's use of renewable energy as a building block is highly problematic because renewable energy is not a dispatchable resource. Thus, renewable resources on a MW for MW basis.
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> * * *
>
> The EPA's Clean Power Plan relies far too heavily on renewable generation resources and DSM energy efficiency programs. As noted previously, neither renewable generation resources nor DSM energy efficiency programs a redispatchable. Therefore, the EPA is requiring states to significantly alter their respective generation mixes by incorporating substantial non-dispatchable resources, which creates significant concerns regarding the reliability of the electrical system.[256]

The Virginia State Corporation Commission made the same point: "EPA's modeling shows 2,851 megawatts of dispatchable, fossil-fuel generation in Virginia being retired and displaced, with 351 megawatts of non-dispatchable on-shore wind [being added]. This raises alarming regional reliability issues."[257]

In sum, different generation resources do not substitute for each other. EPA's faulty assumption that they do creates a series of perverse results in the way EPA determines each

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[254] MISO, Planning Year 2014-2015 Wind Capacity Credit Report, December 2013, available on MISO website.

[255] *See Exelon Wind 1, L.L.C. v. Nelson*, No. 12-51228, 766 F.3d 380 (5th Cir., 2014) (holding that because "[w]ind is a notoriously fickle energy source," slip op. at 6, Texas Public Utilities Commission properly classified it as a non-firm resource that a Texas utility was required to purchase under the Public Utility Regulatory Policies Act, as opposed to firm qualifying resources that utilities are required to purchase).

[256] Comments on the proposed rule of the Kansas Corporation Commission at 27.

[257] Virginia State Corporation Commission comments at 4.

state's "best system." For instance, the amount of renewable power that EPA hypothesizes in its "best" system for Texas would exceed Texas' total demand for electricity in the early morning in the spring and fall. During these periods, the weather is cool and therefore electric load is low but wind generation is high. Under EPA's "best system," therefore, Texas would face the choice of shutting off new wind generators that were built to comply with EPA's proposal, which would be inefficient and uneconomic, or curtailing nuclear generation. But nuclear units were not designed to be curtailed, and once shut down take another 12 hours to ramp back up. Forcing nuclear units to reduce generation to accommodate all the wind that would be built under EPA's "best" system thus would create electricity shortages as the day warms and electric demand increases and wind power decreases, yet nuclear units would not be able to ramp up quickly enough to meet the increasing load.[258]

Another example of the perversity that is created by EPA's assumption that all resources are the same is the way building blocks two and three work at cross purposes. Because wind is so variable, natural gas generators need to be available to ramp up quickly to replace wind generation when the wind stops blowing. Yet EPA's "best" system has all NGCC units operating as base load units (70% capacity factor) in substitution for coal generation, making them unavailable to ramp up to the levels necessary to replace wind generation as wind diminishes. For instance, Basin Electric Power Cooperative designed the Deer Creek NGCC generating station in South Dakota, which became operational in 2012, to run 12-16 hours per day, five days a week. This equates to a 50% capacity factor rather than the 70% capacity factor that EPA believes would be a component of South Dakota's "best system." Basin designed Deer Creek to operate in this fashion in order to integrate Basin's abundant and growing wind resources. Operated at a 70% capacity factor, however, Deer Creek would not be able to achieve

[258] Anderson Testimony at 5-7.

its design function and, counterproductively from EPA's (and Basin's) perspective, Basin would be required to curtail wind generation.[259] EPA's "best system" for South Dakota founders on this reality.

Similarly, because generation resources do not substitute for each other, building blocks two, three and four also work at cross purposes with building block one. As discussed previously, because coal units are designed to operate as base load plants, they become less efficient—and hence produce more CO_2 per MWh, if they are forced to cycle. But, for instance, EPA's "best" system for South Dakota would force the "Big Stone" plant to operate at a 23% capacity factor, which is not only inefficient but below its minimum run level of 40%.[260]

3. The grid does not operate on a state-by-state basis.

In designing its state-by-state "best" systems, EPA wrongly assumes that states can somehow control the dispatch of in-state resources so that, for instance, an in-state NGCC unit can be ramped up and an in-state coal unit can be ramped down to meet EPA's goal. But this is not the case given that states themselves do not control the dispatch of units; units are dispatched by regional grid operators based on regional power needs. Thus, the grid operator might be forced to call on the state's coal and gas plant to meet regional supply needs, depending on the state of the regional market at any one time. Thus, EPA's state-by-state best systems could not exist in the real world.

Moreover, EPA ignores the fact that a number of states are located in more than one regional market. South Dakota is an example. EPA's "best" system for South Dakota would significantly reduce generation at the Big Stone coal plant and replace it with generation from

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[259] Written Testimony of Travis Kavulla, Montana Public Service Commissioner, Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives (Kavullah Testimony), September 9, 2014, available at http://energycommerce.house.gov/hearing/state-perspectives-questions-concerning-epa%E2%80%99s-proposed-clean-power-plan.

[260] *Id.*

the Deer Creek NGCC plant. But the dispatch of these units is controlled by two different operators and therefore they are not seamlessly integrated. Deer Creek is dispatched through the region's Integrated System (IS), operated by Basin Electric and the Western Area Power Administration. In 2016, it is planned that the IS will participate in the Southwest Power Pool (SPP). The Big Stone unit, on the other hand, is dispatched into MISO. IS/SPP and MISO do not share a dispatch signal that would allow one plant's increased operations to result in the lower dispatch of a plant operating in a different market. Nor would there be any economic or logical reason to dispatch the units in a coordinated fashion given that they serve different markets.[261]

Additionally, these two plants were built to their particular size and in their particular locations to serve the needs of their utilities' customer bases, not those of other utilities. Each of the owners of these plants possesses firm transmission rights to ensure that the generation reaches load. Yet EPA assumes falsely, solely because the plants are located in the same state, that they must be part of the same electric system and can therefore be coordinated in their operations.

Similarly, portions of Arkansas are in the SPP and other portions are in MISO. Indeed, SPP, PJM, and MISO cover some of all states and only parts of others, and the Electric Reliability Council of Texas (ERCOT) covers only part of Texas.

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261 *Id.*

Another example of the failure of EPA's state-by-state approach to reflect the interstate nature of the grid is EPA's inconsistent and confusing approach to the interstate dispatch of renewable and fossil resources. Recognizing that renewable power is often sold to out-of-state purchasers, EPA appears willing to at least consider that the state in which the purchaser of renewable power is located should get credit for the CO_2 emissions that the wind unit supposedly avoids, even if the power is produced in a different state, at least to the extent the sale is reflected in a renewable energy credit.[262] Yet the same is not the case for fossil power, even though fossil power is at least as likely to be sold out-of-state as renewable power and can easily be tracked either because the power is sold under firm contracts or through electronic tagging systems. This differential treatment is arbitrary and creates the illogical incentive to operate coal generation in states with relatively less stringent goals, and to curtail coal generation in states with relatively

[262] 79 Fed. Reg. at 34,914.

stringent goals, even though that incentive may not align with the economic and efficient operation of the grid and does not result in reduced CO_2 emissions on a national level.

B. EPA's Selection of 2012 as the Base Year Is Arbitrary.

Given the dynamism of the electricity system and the national economy, no one year, or even several years combined, is representative of "current" conditions for the purpose of establishing a baseline that will then be used to measure future performance over the long-term. For instance, selecting 2006 as the baseline would be arbitrary because it would exclude the recession, but selecting 2007 or 2008 as the baseline would be arbitrary because it would be dominated by the effects of the recession. Even selecting the average of 2006-2012 as a baseline would be arbitrary because it cannot be said that those years are representative of the past or expected future conditions. EPA's NODA recognizes that selecting the single year of 2012 as the base year is arbitrary and seeks comment on whether another year of an average of multiple years should be selected.[263] But any year or combination of years that EPA selects will be arbitrary and will produce winners and losers based on nothing more than the base year.

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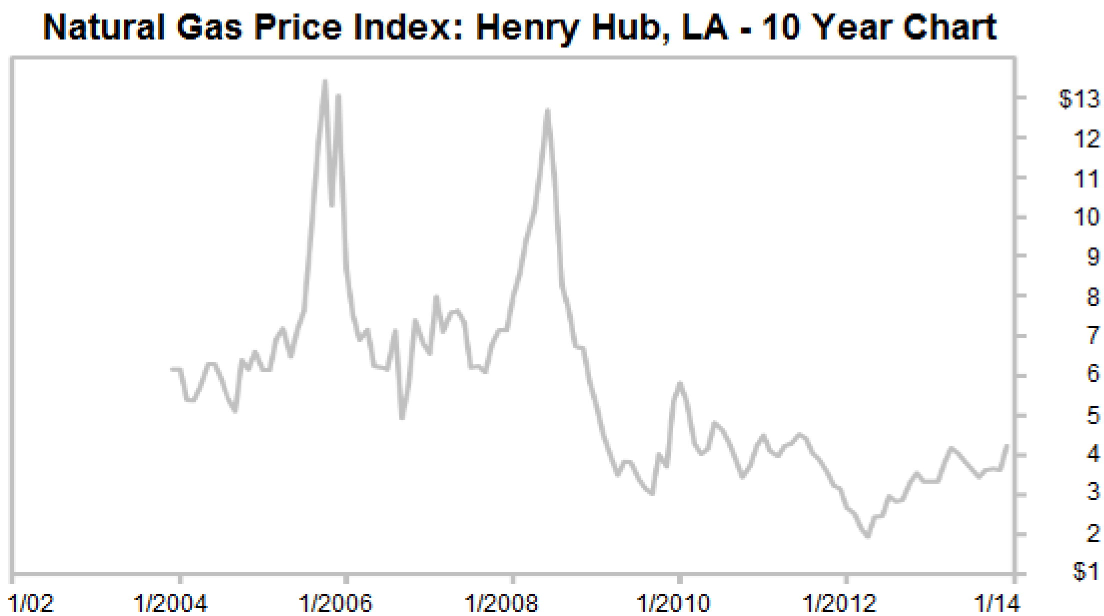
[263] 79 Fed. Reg. at 64,533.

EPA's selection of 2012 as the base year is particularly arbitrary, because it was a highly unusual year in the energy sector. For instance, natural gas prices were historically low:

Natural Gas Index Chart



The above chart plots monthly Natural Gas Price Index: Henry Hub, LA. Measurement is in Dollars Per Million BTU. Source: Dow Jones & Company. Click the links below for the forecast and other links related to this economic indicator. Updated Wednesday, January 22, 2014.

As a result, natural gas generation, both in absolute terms and relative to coal generation, was historically high and has since abated somewhat:

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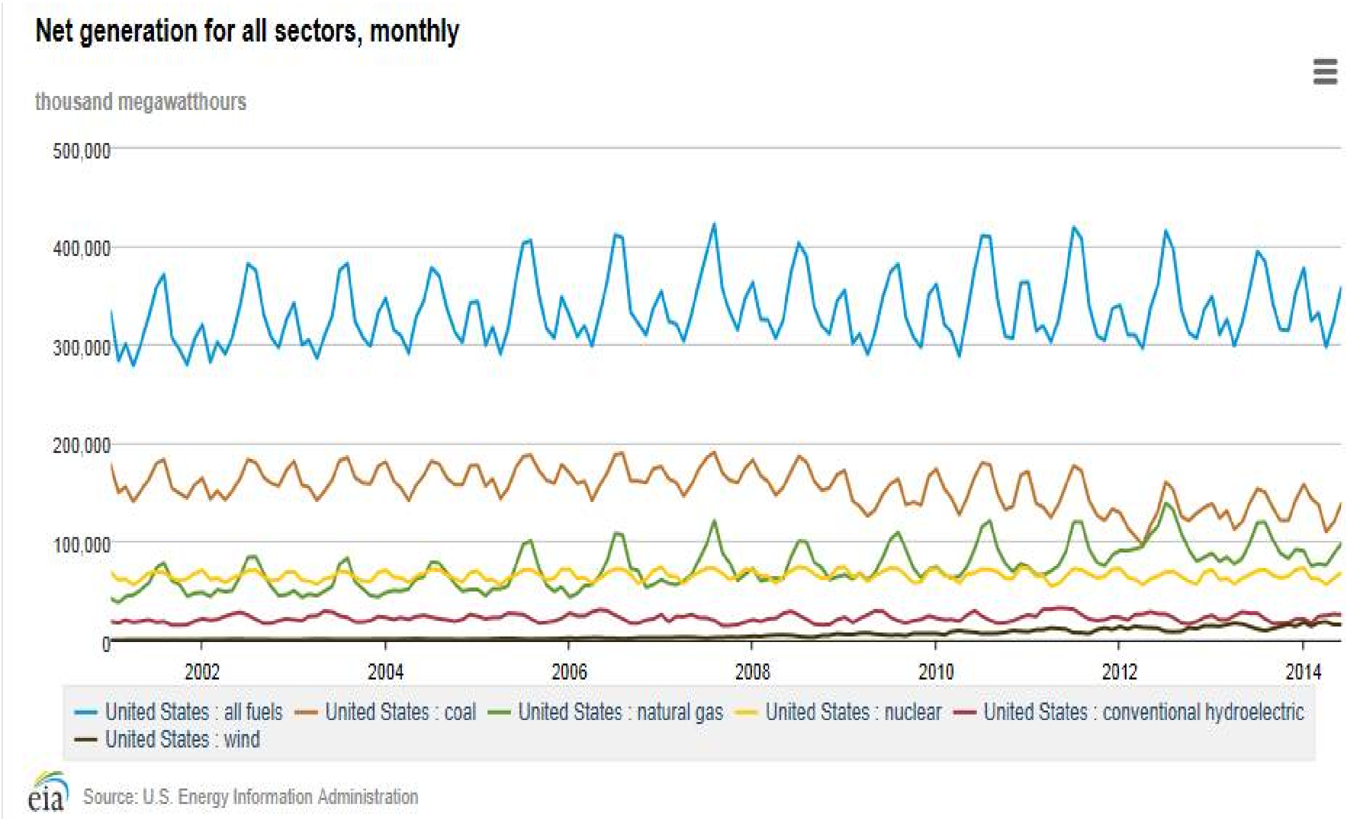

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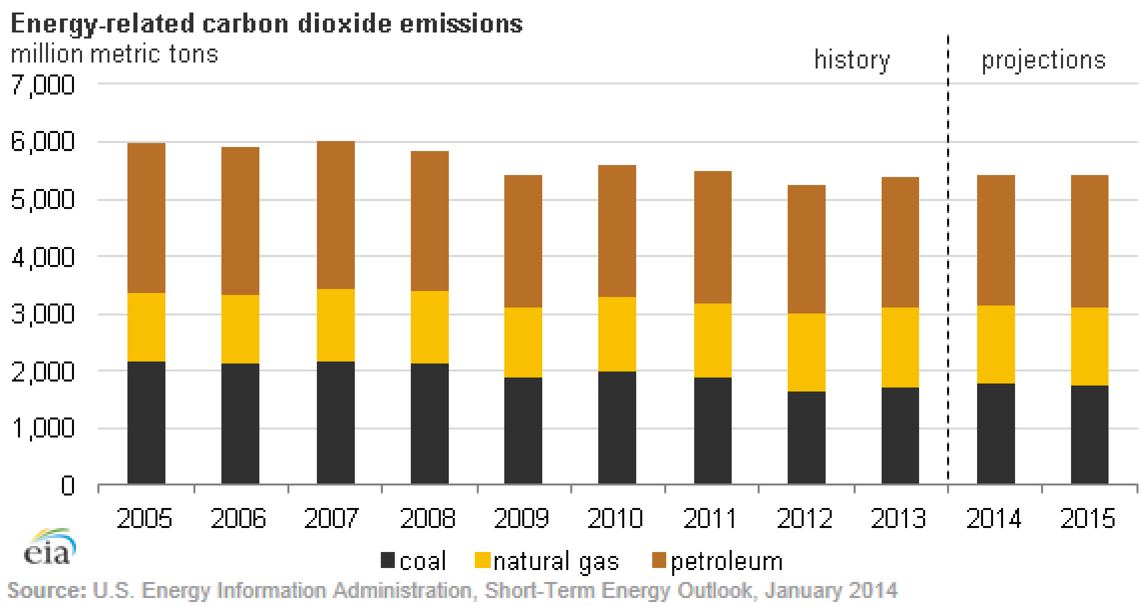
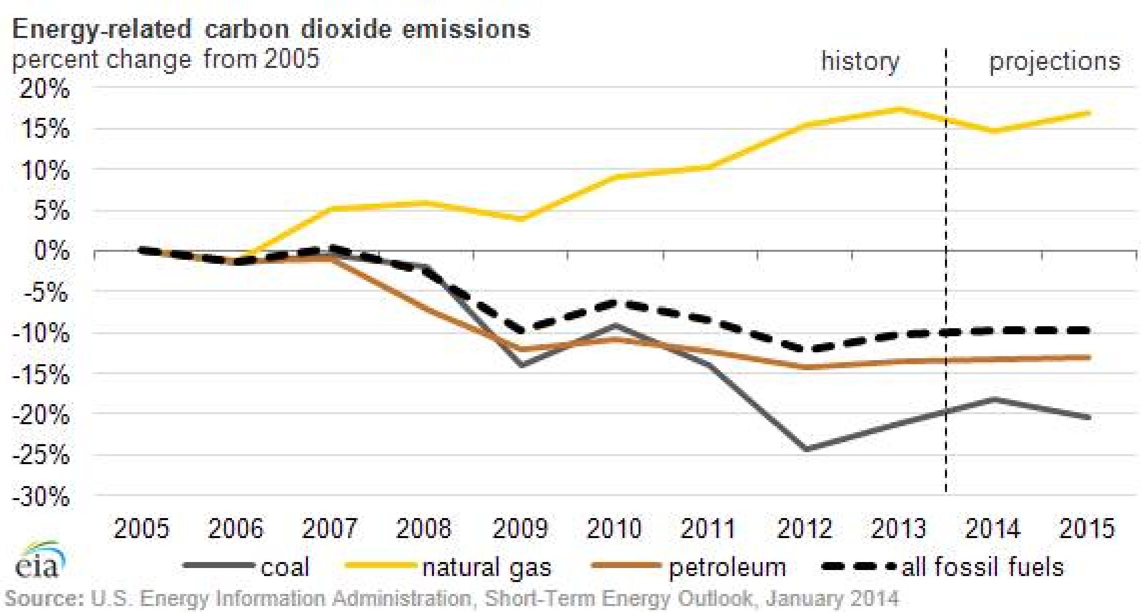
Because of the relatively large amount of natural gas generation relative to coal in 2012, electricity sector CO_2 emissions in that year, as well as coal generation CO_2 emissions, were also significantly lower than they had previously been, and have since increased:





The year 2012 was also a high water year in the Pacific Northwest.[264]

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264 Kavulla Testimony at 16.

These factors combined mean that EPA has set an artificially low baseline for further CO_2 emission reductions. EPA has provided no justification for determining that the year with high amounts of gas generation, low amounts of coal generation, and the low energy-sector CO_2 emissions is a representative year for projecting future performance. There is none.

EPA's selection of 2012 as the base year creates large and disparate impacts for wholly arbitrary reasons. For instance, the amount of natural gas combined cycle generation produced within a state in 2012 has a significant impact on the state's ultimate emission rate "goal" because the 2012 capacity factor for existing natural gas units within a state determines how far the state must go to achieve EPA's 70% capacity factor assumption. Natural gas combined cycle units in Virginia, for example, operated at a 60% capacity factor in 2012. As a result, increasing the dispatch of those units to 70% does not displace as much coal-fired generation as a state with lower 2012 capacity factors, such as Nebraska, where existing combined cycle units operated only at a 10% capacity factor in 2012. Because of the differences in the 2012 baseline underlying EPA's goal calculations, EPA's calculation of Virginia's goal assumes Virginia need only increase natural gas generation by one-quarter of its 2012 levels, whereas EPA's calculation of Nebraska's goal assumes that state must increase its natural gas generation six-fold. Yet if EPA had selected a different year in which Virginia and Nebraska operated their combined cycle units at different levels, their goals would be different.

Even non-emitting generation resources and energy demand in 2012 can have a significant impact on a state's interim and final goals. For instance, states with relatively high renewable generation in 2012 compared to their neighbors may not have as far to go to achieve the regional targets established by EPA, whereas states with relatively low renewable generation in 2012 may have to ramp up generation from those resources much more quickly and extensively. Likewise, states that achieved significant energy savings through existing demand side management programs in 2012 may be better positioned to reach EPA's one-size-fits-all energy savings rate goal in the future. Yet if EPA had selected a different baseline year in which these same states produced lower amounts of renewable electricity or energy efficiency, these states' goals would be different.

Selecting 2012 as the base year also produces anomalies. For example, the 2012 baseline CO_2 emissions level for Minnesota fails to take into account the fact that the state's largest coal-fired unit, Sherburne County Unit 3, was offline for the entire year.[265] Even though the unit has a nameplate capacity of over 900 megawatts, and will certainly be dispatched in future years to produce millions of megawatt-hours, it produced no electricity in 2012 due to a fire that kept the unit offline for the entire year. Thus, EPA's decision to use 2012 as the single baseline year in its analysis resulted in an unrealistically low baseline of coal-fired generation in Minnesota, which presumably will make compliance with the even lower targets set by EPA that much more difficult. Other anomalies likely exist in other states.

C. Building Block One Is Arbitrary and Unsupported.

EPA's building block one would require a significant improvement in the efficiency of coal-fired electric generating units by requiring those units, on average, to reduce their heat rate[266] by 6 percent.[267] As a matter of simple logic, however, EPA's 6 percent number makes no sense. EPA's proposed standards for modified and reconstructed sources sets a standard of 2

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[265] *See* http://www.power-eng.com/articles/2013/10/sherburne-county-coal-fired-power-plant-unit-3-to-return-to-service.html.

[266] 79 Fed. Reg. at 34,861. The heat rate of a plant is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output. *See* Sargent & Lundy 2009 Report

[267] The comments of the Utility Air Regulatory Group and the Edison Electric Institute contain detailed technical analysis showing that EPA's assumption that all coal EGUs can, on average, achieve a 6% efficiency improvement, is significantly overstated.

percent CO_2 emission reduction below the source's best historical performance.[268] If there is a reason to conclude that existing unmodified and unreconstructed units can make better efficiency improvements than modified and reconstructed units, EPA doesn't say what it is.

Moreover, EPA's generic conclusion that the coal fleet as a whole can improve efficiency by 6 percent fails to recognize that the potential for efficiency improvements is highly unit-specific. As the National Coal Council a federal advisory committee reporting to the U.S. Secretary of Energy, recently reported,

> In some cases, the opportunity [for efficiency improvements] will be negligible because the unit either is already operating in a highly efficient mode with some or all of the improvements in place or because the implementation of potential improvements is not cost-effective and/or technically feasible. As such, the degree of efficiency improvement possible at a given unit is highly site-specific, and may depend on the design of the unit, current maintenance procedures, whether the unit operates as base load or cycling, the type of coal used by the unit, system economics and the economics of the specific measure and the configuration of the unit. Even the location of a unit is relevant to efficiency because plant efficiency is sensitive to ambient temperature and atmospheric pressure (elevation).[269]

EPRI has extensively studied the possibility of improving heat rate efficiency at coal generators. It concluded that "[e]stimates of heat rate improvements at existing coal EGUs are very dependent on the individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal."[270] EPRI further warns that the opportunity for heat rate improvements is diminishing as the older, less efficient coal plants either have retired or are retiring.[271] NERC echoed these observations, noting that "[m]ultiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to

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268 79 Fed. Reg. 34,960, 34,861 (June 18, 2014).

269 National Coal Council, "Reliable & Resilient, The Value of Our Existing Coal Fleet" (May 2014) at 4-5 (attached hereto).

270 EPRI Comments at 9.

271 *Id.*

determine any remaining opportunities for economic heat rate improvement measures."[272] Similarly, a detailed review of possible heat rate improvements by industry experts concluded that "the payoff from any given heat rate improvement is highly site-specific.[273]

EPA concluded that a 6 percent improvement was possible by identifying two categories of actions that EPA claims utilities can use to cost-effectively improve the efficiency of their generating units, namely (i) operating and maintenance (O&M) "best practices" and (ii) capital projects.[274] Although the activities EPA identified can have some beneficial impact on the heat rate for coal-fired units, EPA's analysis is rife with unsupported assumptions that in any event have little relation to the analyses EPA claims to have conducted. In reality, a 6 percent heat improvement is not feasible. Indeed, EPA's rules will almost certainly cause a deterioration in coal unit efficiency, rather than an improvement.[275]

1. EPA may not regulate equipment that is not within the Subpart Da category.

Many of the O&M and capital projects that EPA identifies pertain to improvements in operation of the steam turbines. Subpart Da, however, pertains only to steam generating units.[276] EPA has previously provided a drawing that clearly demarcates the steam boiler equipment as subject to Subpart Da and other equipment at a coal-fired generating facility, including the steam turbines, water purification equipment, water-supply systems, air cleaning and cooling apparatus, condensers, main exhaust and main steam piping, water screens, motors, and moisture separator

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[272] NERC Report at 2.

[273] J. Edward Cichanowicz & Michael C. Hein, "Evaluation of Heat Rate Improving Techniques for Coal-Fired Utility Boiler as a Response to Section 111(d) Mandates" ("Cichanowicz & Hein")), October 13, 2014 at 3-1 (attached to comments in this docket of the Utility Air Regulatory Group).

[274] 79 Fed. Reg. at 34,860.

[275] Although EPA included in the docket data showing that 16 units had achieved a 3-8% efficiency gain "year-to-year," the docket contains only one year of data, 2012, showing heat rates and CO_2 emissions on a net basis. Since EPA is requiring compliance on a net basis, EPA's failure to include data in the docket substantiating its claim fatally undermines building block one. *See* September 3, 2014 letter of Utility Air Regulatory Group to EPA.

[276] *See* 40 C.F.R. § 60.40Da (defining "affected facility" as "each electric utility steam generating unit."

for turbine steam, as not being subject to Subpart Da.[277] EPA has improperly included many of these facilities in its building block one analysis. EPA can establish performance standards only for a source "to which a standard of performance under this section would apply if such existing source were a new source."[278] EPA thus cannot, as it has done in its proposed Section 111(d) regulation, include equipment that is not part of the Subpart Da source.

2. EPA's O&M analysis is arbitrary.

EPA claims that improvements in O&M activities alone can achieve, on average, a 4 percent improvement in efficiency at all existing coal-fired units.[279] EPA's preamble indicates that this category of activities includes measures such as such as "turning off unneeded pumps at reduced loads, installing digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn components."[280]

EPA's conclusions as to efficiency improvements from O&M activities, however, are not based on a review of the potential effectiveness of available O&M practices at all. Instead, EPA's 4 percent conclusion depends on the assumption that reducing the variability of coal unit heat rates is possible through "best practices" and that reducing that variability will lead to better performance.[281] As EPA states, it used "heat rate variability as an indicator of the application of best practices and potential for improvement."[282] Although EPA claims it has accounted for all sources of heat rate variability, in fact the Agency accounts for only two—operating load and ambient temperature.[283] According to EPA's own analysis, these two factors explain only 26

277 Memorandum from John B. Rasnic, Acting Dir., Stationary Source Compliance Div., EPA OAQPS, to James T. Wilburn, Chief, Air Compliance Div., EPA (Nov. 25, 1986).
278 42 U.S.C. § 111(d)(1)(A)(ii).
279 GHG Abatement Measures TSD at 2-34.
280 79 Fed. Reg. at 43,854
281 79 Fed. Reg. at 43,860.
282 GHG Abatement Measures TSD, at 2-16
283 79 Fed. Reg. at 43,860.

percent of heat rate variability.[284] EPA assumes that the other "residual" 74 percent of heat rate variability must be within the control of unit operators and so can be improved.[285] But EPA's assumption ignores numerous causes of heat rate variability that are beyond the ability of coal units to control, such as:

- Variability in coal quality, such as heat content (Btus) and moisture. EPA recognizes, for instance, that coal rank quality can have an impact on heat rate,[286] and that reducing coal moisture through drying can improve heat rate (which confirms that high moisture can degrade heat rate.[287]

- Variability in pollution control efficiency and electricity demand (which can also be affected by variability in coal quality). Although EPA recognizes that pollution controls can affect heat rate, it fails to recognize the unavoidable variability inherent in the operation of those controls.[288]

- Variability in other ambient and weather conditions that can impact heat rate, such as humidity and rainfall (which can affect the temperature of the cooling water resource and the moisture of the coal. Although EPA recognizes that barometric pressure and cooling water temperature affect heat rate, it fails to account for anything other than air temperature in its analysis.[289]

- Variability attributable to unavoidable cycles in the degradation of components that are designed to wear out over time (*e.g.*, air heater baskets, pulverizer rollers, baghouse bags, cooling tower fill, etc.). Although EPA recognizes that component replacements can improve heat rate, it fails to account for the varying rates of degradation of components over time that can affect heat rate variability.[290]

- Variability attributable to changes in heat rate calculation method. EPA recognizes that, of the 355 units with large year-to-year changes in heat rate, two-thirds of those large changes were attributable to changes in reporting method. EPA, however, continues o count the data affected by those changes in reporting method in its calculations.[291]

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284 GHG Abatement Measures TSD, at 2-30.
285 *Id*.
286 GHG Abatement TSD, at 2-20.
287 *Id*. at 2-12.
288 See e.g., id. at 2-9.
289 *See,, e.g., id*. at 2-18 and 2-25.
290 79 Fed. Reg. at 34,860.
291 *See e.g.,* GHG Abatement TSD, at 2-29.

- EPA fails to recognize that some plants may have lower heat rate variability for other unavoidable reasons, which may skew the data based on unit characteristics that cannot be replicated at other facilities.[292]

As NERC stated, "[t]he EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU: (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency)."[293]

EPA's analysis thus fails to account for all the possible source of heat rate variability and also fails to address the potential cumulative effect of all of those factors together. In short, EPA has not provided sufficient support for its assumption that the "residual" variability in existing coal unit heat rates can be eliminated through the implementation of improved O&M practices.

3. EPA's capital projects analysis is arbitrary.

EPA's capital analysis relies on a 2009 report issued by Sargent & Lundy, a vendor of the types of equipment EPA now expects its rule will require all units to consider. The report lists the following types of projects that could improve efficiency at existing coal-fired units: upgraded pulverizers, economizer replacements, neural network controls, intelligent sootblowers, improved air heater seals, sorbent injection into air heaters, advanced turbine designs, condenser upgrades and maintenance, boiler feed pumps overhauls, induced draft fan upgrades, variable frequency drive fans, and various projects designed to reduce the electricity used by conventional

[292] For example, the 60-year-old 250 MW McMeekin Power Station located near Columbia, South Carolina, consistently ranks as one of the most efficient coal-fired power plants in the United States largely because of the cold water it receives from the nearby dam of Lake Murray—which provides year-round source of 45 degree cooling water directly from the bottom of the lake—not because it has implemented O&M practices that other plants fail to employ.

[293] NERC Report at 8 (footnote omitted).

pollution control equipment, such as flue gas desulfurization systems, electrostatic precipitators, and selective catalytic reduction systems.[294]

EPA's capital analysis examines four of those projects, specifically economizer replacements, acid dew point control projects, combined variable frequency drive fans, and turbine overhauls. EPA, however, made a simplifying assumption that undermines the validity of the analysis. EPA assumed that half of these projects have not already been completed at existing generators: "We considered that a 4% reduction in heat rate might be achieved on a coal-steam unit by applying the four higher cost upgrade actions described in Table 2-13 above. However, because details of current actual unit configurations are unknown, and some units may have applied at least some of the upgrades, we conservatively estimate the heat rate improvement potential for upgrades at 2%."[295] That assumption, in truth, is not "conservative," because it is little more than a coin-flip, indicating that EPA does not have any basis to estimate, liberally or conservatively, how many coal units may already have undertaken these projects.

Utility companies, however, have likely installed far more than half of the projects EPA cites, particularly if those equipment installations are as cost-effective as EPA claims.[296] The Sargent & Lundy report on which EPA relies was a 2009 study that relied on 2008 data, four years prior to the baseline EPA assumes in its building block formula. As that report stated,

[294] GHG Abatement Measures TSD, at 2-6 – 2-10.
[295] *Id.*, at 2-35.
[296] For instance, the only coal unit in South Dakota, Big Stone, has already made most of the heat-rate upgrades. Similarly, Montana's 2,100-megawatt Colstrip facility—the second-largest coal-fired power plant in the West—has made several efficiency improvements over the last decade that have made the plant operate about 5% more efficiently. These upgrades include an approximately 3-4% efficiency improvement resulting from using a new blade design in the turbine rotors, allowing the plant to use the same amount of steam flow to generate more electricity; a less than 1% efficiency gain from boiler upgrades; and a less than 0.5% efficiency upgrade resulting from cooling tower and fan improvements. Kavulla Testimony at 7.

"[a]ll estimated capital and installation costs are referenced from work in progress and vendor quotes as of the year 2008."[297]

In any event, the Sargent & Lundy study was not designed for rulemaking purposes generally, nor does it support the specific assumptions that EPA has made. For example, the introduction of the report explains that its cost figures are intended to be accurate only on an "order of magnitude" level, and those cost figures are provided only for "comparison purposes" when evaluating the advantages and disadvantages of one project against another.[298] The report specifically notes that those cost estimates "should not be used as a basis for project budgeting or financing purposes."[299] The report also notes that its calculations are based on the hypothetical "design" heat rate of coal units, which units can achieve (if at all) only during full load operation, not the actual heat rate of units, which the reports admits "are usually significantly higher than the design heat rate."[300]

In addition, EPA fails to account for the fact that the capital projects that it expects utilities to undertake have, in the past, triggered review and enforcement under the New Source Review (NSR) program. These enforcement actions are detailed in the comments of the Utility Air Regulatory group. Unless EPA exempts these projects from NSR review, utilities will not undertake them given the additional costs they will incur to meet Best Available Control Technology (BACT) requirements. At a minimum, EPA's failure to consider these additional BACT costs in assuming that utilities can undertake the assumed capital improvements is arbitrary.

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297 Sargent & Lundy 2009 Report at 1-3
298 *Id.* at 1-1, 1-3.
299 *Id.*
300 *Id.* at 1-1.

In sum, EPA's claim that coal units can undertake capital projects that will improve heat rates by 2 percent is based on a mischaracterization of the Sargent & Lundy report and is little more than a guess.

4. EPA has no basis to conclude that units can make both O&M and capital improvements.

Based on EPA's assumptions, an existing coal unit will be able to achieve a 6 percent improvement only if it *both* has high variability in heat rate that is attributable to poor O&M practices and has not already completed at least half of the available capital projects designed to improve heat rate. While some units may fit this description, EPA presents no information that a majority of units, or even a large number, can make both the operating and capital improvements EPA assumes. EPRI warns that its research shows that "heat rate improvements are not necessarily additive."[301] As Cichanowicz & Hein showed, the benefits of different efficiency measures are not cumulative.[302]In the same vein, EPA's analysis is nationwide and generic, and so does not account for the likelihood that certain states will have fewer units that fit EPA's description than the national average. The goals for those states, therefore, will be arbitrarily strict.

5. EPA failed to account for the diminishing effects of heat rate improvements.

EPA admits, at it must, that the heat rate at many units slowly degrades over time, regardless of the measures employed: "Over 40% of units have a positive slope [to the annual heat rate trend line]. This would imply that equipment maintenance and upgrades at a significant fraction of the study population have not been sufficient even to maintain the status quo."[303] As Cichanowicz and Hein found, "[t]he thermal efficiency of generating power from fossil fuel

301 EPRI Comments at 9.
302 Cichanowicz & Hein at 4-4 – 4-6.
303 GHG Abatement TSD, at 2-34.

plants degrades with time, both due to component wear and changes in plant operation. Component wear is inevitable."[304]EPA, however, fails to take into account this natural degradation in heat rate, and instead assumes that "other factors are held equal."[305]

6. EPA's proposed rule will actually cause heat rates to rise.

EPA recognizes that units operating at lower than optimum capacity factors will have sub-optimal heat rates: "Coal-fired units are designed to operate most efficiently at full capacity. As a unit drops below this level, in general, heat rate will increase."[306] This obvious fact was confirmed by Cichanowicz & Hein. Examining the operating history of 28 units, they found that on average the plant rate heat penalty (gross basis) incurred at 50 percent load is about 7 percent for subcritical boilers and 4 percent for supercritical boilers.[307] Examining the sixteen units that EPA relied on in building block one, they found that the heat rate penalty (gross basis) at these units incurred at 50 percent load is 7 percent for subcritical boilers and 9 percent for supercritical boilers.[308] NERC made the same point:

> Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.[309]

EPA's proposal, however, will reduce coal unit capacity factors, thereby increasing coal unit heat rates. EPA expressly admits that building block two—increased natural gas generation—will displace coal: "The electric system's carbon intensity can be lowered through re-dispatch among existing EGUs, particularly by shifting generation from coal-fired units to

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304 Cichanowicz & Hein at 4-3.
305 *See, e.g.,* GHG Abatement TSD, at 2-28, 2-30
306 *Id.* at 2-23.
307 Cichanowicz & Hein at 2-6.
308 *Id.* at 2-7.
309 NERC Report at 8.

natural gas combined cycle (NGCC) units."[310] But EPA fails to recognize that shifting generation from coal to gas will reduce coal unit capacity factors and therefore increase coal unit heat rates, thereby undermining EPA's goal of improving coal unit efficiency.

In addition, although EPA does not admit it, building blocks three and four will also necessarily displace coal generation, further reducing coal unit capacity factors and increasing their heat rates. Electric generation supply and demand must remain in balance, so if, as EPA is requiring, more "clean" electricity is generated and more electricity is conserved, another form of generation must be concomitantly reduced. Since coal is the most carbon intensive generation, the overwhelming likelihood is that coal will be displaced. As a result, like building block two, building blocks three and four will reduce coal unit capacity factors and increase coal unit heat rates. EPA completely fails to take this into account in its building block one calculations.

7. EPA failed to consider that its other utility regulations will also retard coal unit efficiency.

EPA fails to account for the fact that its other regulatory initiatives that it has recently imposed on the utility sector will also degrade coal unit efficiency. For example, EPA's Mercury and Air Toxics Standards, Cross-State Air Pollution Rule, Effluent Limitation Guidelines, and Clean Water Act Section 316(b) Cooling Water Intake Structure Rules, all of which will take effect in the next few years[311] are each expected to require existing coal plants to install new equipment that will require additional parasitic load, also known as station service, that reduces the amount of the "net" electricity generated that can be sold to the grid. As EPA states, "[t]he electric power consumed by air pollution control equipment reduces the overall

[310] *Id.* at 3-2.
[311] 79 Fed. Reg. at 34,929-931.

efficiency of the EGU."[312] As more and more equipment at the facility requires more and more of the electricity generated, less electricity will be available for distribution, resulting in a lower net heat rate. Since EPA's goal calculation is based on pounds of CO_2 per *net* megawatt-hour, the increase in parasitic load required by EPA's many other rulemakings will present a direct impediment to achieving the 6 percent efficiency improvement that EPA desires. EPA fails to account for this drop in efficiency in claiming that a 6 percent improvement is achievable.[313]

8. EPA failed to consider that NSR permitting requirements discourages heat rate improvements.

As EPRI's comments reported, a National Energy Technology Laboratory workshop reported that NSR permitting requirements is one of the largest barriers to heat rate improvement projects.[314] The National Coal Council came to the same conclusion.[315] NMA understands that UARG's comments will show that many of the heat rate improvement projects that EPA cites have triggered NSR enforcement actions by EPA. EPA, however, does not include in its BSER analysis the additional costs of NSR permitting and the very significant and costly BACT requirements that a unit must meet to obtain a permit. EPA's failure to do so is arbitrary and capricious.

D. Building Block Two Is Arbitrary and Unsupported.

EPA's building block two would require states to displace coal generation by increasing the utilization of their existing natural gas combined cycle units (NGCCs) to 70 percent.[316] According to EPA, this assumption would significantly reduce coal generation in many states

312 GHG Abatement Measures TSD at 2-4.
313 *See also* discussion in Cichanowicz & Hein at 2-7 – 2-9.
314 EPRI Comments at 13.
315 National Coal Council, "Reliable & Resilient, The Value of Our Existing Coal Fleet" (May 2014).
316 79 Fed. Reg. at 34,857.

and eliminate it entirely in 12 states.[317] EPA's assumptions regarding the ability of states to require such significant increases in natural gas generation, however, are unrealistic and unsupported.[318]

1. EPA failed to cite any mechanism that could require natural gas generation to operate at a 70 percent capacity factor.

Although EPA considers each state's "best" system to be one in which all NGCC generators operate at a 70 percent capacity factor, EPA completely fails to provide any information as to how a state would go about obtaining that result, even if it believed that such result was desirable. Neither EPA nor states—nor even FERC—has the authority to order natural gas generators to operate at that or any other capacity factor. A state PUC, through an IRP, could require a utility to acquire additional NGCC assets, but whether those assets will run at a particular capacity factor will depend on market conditions, including natural gas prices. EPA's "best" system therefore depends on a factual impossibility—the notion that NGCC units should operate at a 70 percent capacity factor when that level of operation is beyond the power of the state to command.

2. EPA failed to support its 70 percent capacity factor assumption.

EPA's assumption that a 70 percent capacity factor is achievable on average at all NGCC units is based on two facts: (i) 10 percent of NGCCs achieved a 70 percent capacity factor for one year (2012) and (ii) 20 percent of NGCCs achieved a 70 percent capacity for at least one season (during 2012).[319] This evidence is insufficient as a matter of law to support the conclusion that all NGCC units in every state can operate at 70 percent capacity factors. The fact

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317 Alaska, Arizona, California, Connecticut, Maine, Massachusetts, Mississippi, Nevada, New Hampshire, New Jersey, Oregon, and Washington, as shown on the EPA spreadsheet at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents-spreadsheets. .

318 The comments of the American Coalition for Clean Coal Electricity contain a detailed analysis showing that EPA's assumption that all existing natural gas combined cycle generation can operate at a 70% capacity factor is unreasonable.

319 GHG Abatement Measures TSD at 3-9.

that only 10 percent of the NGCC units that operated in 2012—a year of exceptionally low natural gas prices—did so at a 70 percent capacity factor is more indicative of the *inability* of all NGCC units to operate at that level than the opposite. Moreover, EPA does not provide any information showing that any of the units that operated at a 70 percent capacity factor in 2012 did so in previous years, yet EPA assumes that these and other units can operate at that level indefinitely into the future. Presumably, if a significant number of NGCC units had operated at 70 percent capacity factors over longer periods of time, EPA would have cited that fact.

Similarly, the fact that some NGCC units operated at a 70 percent capacity factor in certain seasons is not representative of how these units could operate year-round. Units that are able to reduce load or shutdown during non-peak seasons are better able to prepare for the peak seasons when higher operating levels are needed than units that do not have that opportunity. Accordingly, EPA cannot simply assume that seasonal performance is a fair benchmark of continuous, year-round performance.

Moreover, EPA did not conduct any analysis to understand why a small number of units operated at a high capacity factor while the large majority did not. EPA recognized that units operating above a 70 percent capacity factor on an annual basis were "largely dispatched to provide base load power," whereas units that met that level seasonally "were idled or operated at lower capacity factors" during periods of lower demand.[320] There could be a number of reasons why certain units are able to operate in a baseload mode all year, whereas certain units can do so only seasonally and certain other units cannot do so at all. For instance, all NGCC plants have operating permits that limit emissions, and these permits may limit the number of hours these facilities may operate, particularly during the summer ozone season. Or a utility may build an NGCC unit specifically to operate in an intermediate mode because it already has other baseload

[320] 79 Fed. Reg. at 34,863.

resources. As Montana Public Service Commissioner Travis Kavulla explained, utilities build different types of facilities in different locations to serve discreet purposes. These facilities cannot be operated in a different fashion to serve a different purpose without undermining their ability to serve their original purpose. For instance, Basin Electric Power Cooperative designed the Deer Creek NGCC facility, which became operational in 2012:

> to run 12-16 hours per day for five days a week; in other words, it was intended to operate a little less than half of the time, not 70% of the time. One of the reasons it was designed in this way is to integrate Basin's substantial and growing portfolio of wind energy, which is abundant in this part of the nation. Deer Creek needs to have the capability to dispatch up when the wind suddenly does not blow, and need to be able to dispatch down when the wind picks up. Operating at a high capacity factor, 70%, would not allow the kind of ramping that is essential to Deer Creek's purpose.[321]

EPA's conclusion that because a small number of NGCC units operated at a 70 percent capacity factor in 2012, all can is therefore arbitrary.

3. EPA failed to support its claims that sufficient natural gas will be available to fuel all of the additional NGCC generation.

Obviously, if NGCC units are going to substantially ramp up generation, natural gas supplies will also have to be significantly expanded. Yet EPA's analysis of the ability of the country to sharply expand generation is meager, just one page out of a 224-page technical support document that EPA uses to explain its building block assumptions.[322] In that short discussion, EPA recognizes that it took twelve years, from 2000 to 2012, to increase natural gas production by 32 percent.[323] That is almost exactly the same level of increase in natural gas production that would be needed to satisfy EPA's building block two 70 percent NGCC capacity

[321] Kavulla Testimony at 10.
[322] *See* GHG Abatement Measures TSD at 3-12.
[323] *Id*.

factor assumption[324]—only this time that increase would have to occur much more quickly and from a higher baseline. Even if those efforts began today, they would have to be completed by 2020, according to EPA's assumptions, which is just over five years away. Moreover, if those efforts do not begin until states finish developing their implementation plans (or, more likely, EPA approves those plans), only a few years would be left before the significant amount of additional natural gas supply would be needed to support EPA's proposal. EPA has no basis for assuming that the unprecedented growth in natural gas supplies from 2000 to 2012 can be similarly replicated in half of that time or less, particularly since each additional cubic foot of gas is likely to come at incrementally higher price than the previous one and given the large pipeline infrastructure investments which must be planned, permitted and constructed in that same time period.

Moreover, EPA's analysis is also devoid of any discussion of the cost and timing of the needed natural gas infrastructure. Yet the issue of ensuring that there is sufficient natural gas infrastructure to fuel the nation's growing dependence on natural gas generation for electricity has become one of the most critical issues in the energy sector. FERC has initiated a natural gas-electric coordination docket, with staff issuing quarterly progress reports and the Commission holding periodic technical conferences to monitor the issue.[325] As discussed more fully below, last winter's cold weather exposed a shortage in firm pipeline capacity that brought the grid close to collapse. As FERC's Director of Office of Electric Reliability stated, in discussing his informal comments to EPA, "I concluded by saying that we had doubts about the ability to

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324 As EPA's TSD recognizes, total natural gas generation would be expected to increase from 959 TWh to 1,444 TWh (an increase of 34 percent) under its building block #2 assumptions. *See* GHG Abatement Measures TSD at 3-11.

325 *See* FERC Docket No. AD12-12-000, Coordination between Natural Gas and Electricity Markets.

expand pipeline infrastructure as quickly as the emission targets implied."[326] FERC Commissioner Clark has warned that "my biggest concern relates to whether there will be sufficient pipeline capacity to supply the need for electric generation."[327] FERC Commissioner Moeller testified that EPA "assumes that there will be sufficient pipeline expansion to meet this new gas demand, which seems unlikely…."[328] NERC also raised red flags on this issue:

> Timing of these [pipeline infrastructure] investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.[329]

Even before EPA's proposal, the natural gas industry was estimating that more than $640 billion in capital would be required to meet expected natural gas and liquids infrastructure needs, a figure that is $300 billion higher than had been estimated in 2011.[330] Given that EPA's proposal will require even more capital to be spent in a shorter amount of time, EPA's failure to comprehensively examine how the natural gas infrastructure required by its proposal would be funded, and who would pay for it, renders the proposal arbitrary.[331]

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326 Memorandum from Mike Bardeee to File re "Phone call on EPA's draft rule for GHG from existing power plants," Apr. 25, 2014, attached to responses of FERC Chair Cheryl LaFleur for the record in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://en ergycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

327 Responses of FERC Commissioner Tony Clark to further questions in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

328 Responses of FERC Commissioner Phillip D. Moeller to further questions in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

329 NERC Report at 10.

330 INGAA Foundation, North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, March 18, 2014, at 39-40, available at www.ingaa.org/File.aspx?id=2149.

331 NMA discusses the impacts EPA's overreliance on natural gas will cause in greater detail below.

Given that building block two dominates the rule's near-term compliance requirements, the inability of industry to develop the necessary infrastructure in the time frame EPA is demanding is a critical failing of the rule. A further, more detailed critique of EPA's assumptions as to natural gas is provided in Section VII.C below.

4. EPA's NODA "proposal "to delay implementation of building block two to allow time for infrastructure development is insufficiently developed to allow comment.

Apparently conceding that the needed pipeline and electric transmission capacity cannot be ready by 2020, EPA's asks for comment on possibly delaying full implementation of building block two until the necessary infrastructure is available.[332] But the concept on which EPA seeks comment is too vague to permit effective comment. EPA states only that the delay would be based on two factors, "the amount of utilization shift to natural gas that is feasible to 2020" and "how quickly that amount could grow until the full amount of natural gas utilization could be achieved as part of the BSER."[333] There is not, however, any one-size-fits-all formula, applicable in each state, for how long it would take to build the necessary infrastructure to allow for the tremendous ramp-up of natural gas generation that EPA's building block two posits, even if that ramp up is even feasible over any period of time. Depending on the state of infrastructure across the country, it might take one state five years and another ten. EPA's proposal does not set forth whether these individual state differences would be considered and, if so, whether it would be EPA or the states that would determine the additional time required. Nor does EPA state whether a loosening of the stringency of state goals in the early part of the 2020s, because of the need to develop infrastructure, would result in a compensating tightening of the goals in

[332] Notice of Data Availability, 79 Fed. Reg. at 64,548.
[333] *Id*.

the latter part of that decade. Without this information, it is impossible to offer intelligible comment on the concept.

The fact that EPA felt the need to seek comment on a delay in building block two confirms the utter infeasibility of the standard as proposed. Instead of floating last-minute ideas for Band-Aid-like fixes to the proposal, EPA should withdraw the proposal in its entirety.

5. EPA's NODA concept of allowing states to use new NGCC generation and re-firing as building block two compliance options won't work.

As proposed, building block two "redispatched" coal only to existing and under construction natural gas generation; it did not assume the construction of new gas or refiring existing coal. EPA says in the NODA that building block two did not assume new construction and refiring because doing so would be more expensive than running existing generation at higher capacity factors (and therefore would not qualify as BSER). But EPA now recognizes that the building block two methodology advantages states that do not have any or much NGCC generation and disadvantages those that do. To cure this disparity, EPA seeks comment on ways that new NGCC generation and generation re-fired from coal to gas could be considered in building block two. EPA also seeks comment on co-firing.[334]

EPA's proposal, however, is flawed. First, EPA does not address how NGCC generation and co-firing could have been too uneconomic to justify as a part of a BSER for purposes of the proposal but can now be transformed into economic resources that can be a part of a BSER. As proposed, building block two assumed redispatch of only existing and under-construction NGCC facilities because EPA assumed (wrongly) that these facilities could easily ramp up generation without the need for new infrastructure development. EPA did not include new and refired NGCC facilities because the cost and time involved in building these new facilities and the

[334] 79 Fed. Reg. at 64,549-50.

associated pipeline and transmission capacity would be uneconomic. The NODA lacks any technical analysis that would demonstrate that new NGCC and refired generation qualify as a component of BSER. Lacking that analysis, EPA cannot now declare that new NGCC and refired generation can be included in building block two.

Second, by definition, EPA cannot regulate facilities as a part of Section 111(b) and Section 111(d). But that would be the result if EPA includes new NGCC and refired generation in building block two. Both types of generation are subject to EPA's proposed GHG NSPS standards. They cannot now become part of EPA's Section 111(d) regulation.

6. Coal generation and natural gas generation are not fully fungible.

EPA's building block two assumes that coal generation and natural gas generation are fungible, with each KWh of increased natural gas generation substituting for a KWh of coal generation. But, as touched on above, coal generation and natural gas generation serve different functions.

First, coal generators serve an important function in providing local reliability support, including black start capabilities (the ability to restart without any electrical input), voltage stability, and other ancillary services. As a result, certain coal facilities may be "reliability must run" units which cannot be retired without imperiling local grid reliability. As a Western Electricity Coordinating Council study stated:

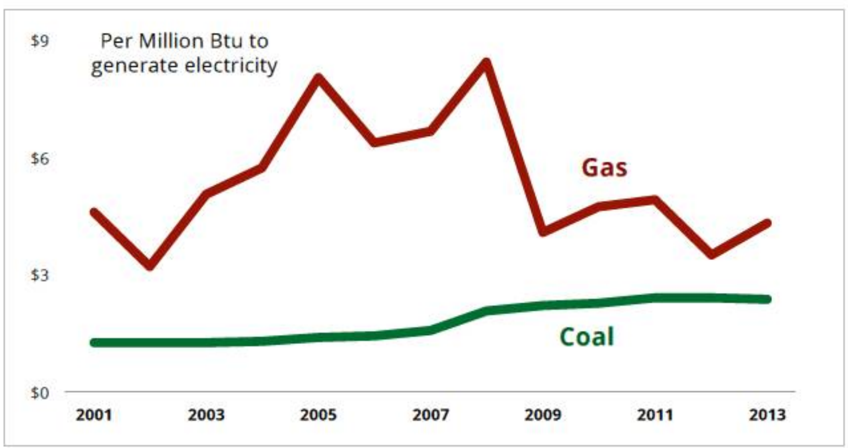
> The path rating for Path 8 [the Montana to Pacific Northwest corridor] is currently highly dependent on remedial action schemes that are directly linked with the coal-fired and hydro generation in Montana. There are inertial concerns in the area. The local balancing authorities have advised caution when running studies that dispatch renewable generation before coal-fired and hydro generation. In reality, the rating on Path 8 may have to be decreased when these conventional resources are backed down, or turned off completely.[335]

[335] WECC, "2022 Resource Options" (July 25, 2013), p. 51.

EPA therefore cannot presume that these units can be retired or curtailed in favor of increased natural gas generation.

Second, coal units have the ability to stockpile fuel on site, whereas natural gas units receive their fuel through pipelines and are therefore vulnerable to pipeline disruptions. As reported by FERC, during last winter's cold weather, numerous natural gas generators were forced to cease generation because of interruptions in pipeline deliveries, both because of the physical inability of frozen pipelines to deliver natural gas and because suppliers cut off interruptible load to serve other load under much higher spot prices.[336] EPA failed to consider these real and negative consequences in determining that every state's "best" utility system should entail the wholesale substitution of natural gas for coal.

Third, as shown in the chart below, based on EIA data, coal prices have historically been low and stable, whereas natural gas prices have been volatile.



Source: U.S. Energy Information Administration.

States may therefore have valid reasons for wishing to maintain a significant percentage of their electric generation in coal rather than in switching to natural gas. Yet EPA's calculation of each state's "best" system fails to account for fuel-pricing stability,

[336] FERC, Winter 2013-2914 Operations and Market Performance in RTOs and ISOs, April 1, 2014.

7. EPA uses mismatched coal and gas generation data to arbitrarily make the state goals more stringent.

Although EPA claims it has applied building block two on a "net" basis,[337] EPA's target for increased natural gas generation actually reflects a calculation of "gross" generation. EPA developed its gas generation target by applying a 70 percent capacity factor to the "nameplate" capacity of existing gas units.[338] "Nameplate" capacity refers to the total "gross" MW; it reflects the maximum amount of electricity that a unit's generator is designed to deliver, not the amount of electricity that eventually may be sold to the grid.[339] Therefore, EPA's 70 percent capacity factor calculation actually reflects gross MWh, not net MWh, artificially inflating the amount of gas MWh that are available to displace coal. On the other hand, EPA's figures for 2012 coal-fired generation are based on "net" generation.[340]

Because EPA inflated the amount of natural gas generation presumed to be available to displace coal generation, EPA assumed coal unit generation will be reduced more than it actually will if NGCC units operate at a 70 percent capacity factor. The effect of this erroneous calculation is not insignificant. As EPA explains, "the difference between gross and net electricity is the amount of electricity used at the plant to operate components such as pumps, fans, motors, and pollution control devices," which "may represent from 4 to 12 percent of gross generation at a coal-fired steam EGU."[341] In other words, EPA's arbitrary inflation of the amount of natural gas generation available for "re-dispatch" may account for as much as twice as great a difference in total generation as EPA's entire building block one assumption of 6 percent.

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337 GHG Abatement Measures TSD at 3-6,

338 *Id. See also* Goal Computation TSD at 10.

339 *See* 40 C.F.R. 72.2.

340 *See* Goal Computation TSD at 7-8 (confirming that EPA determined "net" generation from coal units as the baseline for its goal calculations).

341 79 Fed. Reg. at 34,859, n.111, *id*. at 34,860.

E. Building Block 3 as to Renewable Energy Is Arbitrary and Unsupported.

EPA claims that states should be able to dramatically increase their use of renewable resources by the adoption of "best practices," meaning every state should adopt renewable portfolio standards and most of those who have already done so should adopt more aggressive standards. But the amount of renewable power EPA thinks can be brought on line within the compliance timeframes of the rule is manifestly unreasonable. As an expert report attached to the comments of the Utility Air Regulatory Group shows, EPA's projections assume that the country can increase the annual rate of growth of new renewable resources over projected growth rates by a factor of five. The country is already bringing new renewable resources on line at an unprecedented rate. The notion that the country can quintuple this rate of growth lacks a rational basis.

Even if the country could site, permit and build all of this additional renewable power,, EPA fails to address the obvious need for new transmission to support this renewable development. A host of experts has warned EPA of the long lead times needed to construct transmission in order to support EPA's renewable resource targets. The major reason that the SPP cites as to why EPA's proposal will lead to "cascading outages and voltage collapse" is because it will take at least eight years to build transmission necessary to support the alternative resources the rule will require.[342] The Director of FERC's Office of Electric Reliability warned EPA that "it is difficult to get transmission built for [renewable] generation when it is remote from loads, e.g., wind farms."[343] FERC Commissioner Tony Clark testified to Congress that

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342 Comment letter of Southwest Power Pool to EPA, October 9, 2014, p. 4.

343 Memorandum from Mike Bardee to File re "Phone call on EPA's draft rule for GHG from existing power plants," Apr. 25, 2014, attached to responses of FERC Chair Cheryl LaFleur for the record in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

"[i]n the case of large renewables like utility-scale wind and solar, transmission investments are likely to be needed to hook up remote generation to the existing transmission grid."[344] EPA's failure to even consider the need for additional transmission, let alone the time and multibillion dollar cost involved, fatally undermines building block three.

Apart from these obvious defects, building block three is based on a misunderstanding of state renewable portfolio standards and the Agency's role as an environmental rather than an energy regulator.[345]

1. There are no "best practices" for renewable portfolio standards.

EPA claims facilely that the decision of 28 state legislatures to adopt renewable portfolio standards shows that adopting similar standards would be "best practices" for the remaining 22 states.[346] But EPA fails to note that renewable portfolio standards represent a legislative choice to trade off higher electric costs for the presumed environmental and economic development benefits of renewable power. Some states, particularly those in the middle of the country have access to significant wind resources, and some states, particularly in the southwest, have access to significant solar resources. In virtually all of these states, the legislatures have made the policy choice to adopt portfolio standards. Conversely, a number of states do not have access to renewable resources in significant quantities and have made the choice that imposing portfolio standards is not justified by the cost. Thus, the standards that wind-rich Texas has adopted have no bearing on the standards that wind-poor Louisiana either decides to adopt or not adopt. There are therefore no "best practices" that can be imported from one state to another, nor as discussed

[344] Responses of FERC Commissioner Tony Clark for the record in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

[345] The comments of the American Coalition for Clean Coal Electricity contain a detailed analysis showing that EPA's assumed renewable energy levels are unsupported.

[346] GHG Abatement Measures TSD at 4-11 – 4-13.

above, is EPA in the position, as an environmental regulator, to dictate to states what "best practices" as to renewable energy should be.

The Virginia State Corporation Commission aptly observed:

> If, as EPA assumes, the legislature of one state can speak to what is achievable in another, which it cannot in this context, that assumption would have to work both ways. There are many reasons, including geographic and economic, why States have approached renewable generation differently. And, just as Virginia's legislative decision not to impose RPS requirements in Virginia was not intended to, and cannot, speak to what is achievable or unachievable in other States, the decisions of other States to impose RPS requirements were not intended to, and cannot, demonstrate what is achievable in Virginia. To foist in-state decisions upon other States, and to do so while ignoring the contrary decisions of other States, is arbitrary, capricious, and unlawful.
>
> Another fundamental problem with EPA's addition of future renewable generation into the calculation for Virginia's Mandatory Goals is that it does not establish what has been adequately demonstrated in Virginia, as required by the plain text of the Clean Air Act. For the eight States in the "East Central" region in which EPA places Virginia, EPA's data shows that the renewable generation in 2012 ranged between 1 to 3%, with Virginia at 3% for that year. This is the level of renewable generation that has been adequately demonstrated in Virginia. That other States have future legislative requirements – and no assurance that they will be met – does not change the reality in Virginia.[347]

Indeed, EPA engages in self-contradiction by claiming that states that have adopted renewable portfolio standards are demonstrating "best practices." In fact, EPA's goals for renewable energy development require most states to obtain more, sometimes considerably more, renewable resources than their legislatures have mandated in the state's applicable portfolio standard. The reality is that what EPA calls "best practices" are really only EPA's outcome-driven assumptions as to the type of portfolio standards that it thinks state legislatures should adopt.

[347] Virginia State Corporation Commission comments at 32-33 (footnote omitted).

2. EPA's regional approach is arbitrary.

EPA's approach to defining the amount of renewable resources each state should have is based on grouping states into regions.[348] EPA justifies this grouping by claiming that "[s]tates within each region exhibit similar profiles of RE potential or have similar levels of renewable resources."[349] But this claim is belied by EPA's own data. In examining its renewable portfolio alternative approach, in which hydroelectricity would be included as a renewable resource, EPA provides information as to the amount of each type of renewable resources, including hydro, that each state currently produces. This information is tabulated below.[350]

Region	Renewable Energy Potential (GWh)			Percent Renewable Energy Generation (2012)
	Resource:	**Low**	**High**	
West	Solar: Wind: Hydro: Total:	1,933,554 (WA) 17,709 (NV) 846 (NV) 2,010,600 (WA)	33,202,248 (NM) 2,746,272 (MT) 30,024 (CA) 4,615,701 (NM)	5% (UT) – 87% (ID)
North Central	Solar: Wind: Hydro: Total:	4,975,001 (IN) 143,908 (MI) 347 (ND) 5,354,751 (WI)	11,643,106 (SD) 2,901,858 (SD) 7,198 (MO) 14,546,011 (SD)	2% (MO) – 74% (SD)
South Central	Solar:	4,170,275 (LA)	62,075,015 (TX)	3% (LA) – 12% (OK)

[348] GHG Abatement Measures TSD at 4-12.

[349] *Id.*

[350] Alternative RE Approach Technical Support Document, at 10-11, 21-22. We do not include geothermal on this list because this resource is largely confined to the west.

Region	Renewable Energy Potential (GWh)			Percent Renewable Energy Generation (2012)
	Resource:	Low	High	
	Wind:	935 (LA)	5,552,400 (TX)	
	Hydro:	2,423 (LA)	6,093 (AR)	
	Total:	4,173,633 (LA)	67,630,421 (TX)	
Southeast	Solar:	1,850,491 (KY)	5,535,350 (GA)	2% (FL) – 12% (TN)
	Wind:	0 (MS)	2,037 (NC)	
	Hydro:	682 (FL)	5,745 (TN)	
	Total:	1,854,893 (KY)	5,537,661 (GA)	
East Central	Solar	55,718 (WV)	3,712,677 (OH)	2% (OH,NJ,DE) – 7% (MD)
	Wind	22 (DE)	129,143 (OH)	
	Hydro:	31 (DE)	8,368 (PA)	
	Total:	65,078 (WV)	3,844,866 (OH)	
Northeast	Solar:	15,424 (RI)	1,545,369 (NY)	1% (RI) – 54% (ME)
	Wind:	62 (CT)	63,566 (NY)	
	Hydro:	59 (RI)	6,711 (NY)	
	Total:	15,613 (RI)	1,615,646 (NY)	

Viewing this data, no conclusion is possible other than that EPA's groupings are entirely arbitrary given the wide range of renewable resources that states within a region produce. As can be seen, in many of the regions, a single state dominates the statistics—such as Texas and New York—which clearly have far greater total renewable resources available for achieving the growth rates that EPA's primary proposal would expect. The narrowest margin in total renewable energy resources is nearly 300%, for the North Central region, where South Dakota has nearly three times the renewable resources as the state with the lowest renewable energy potential, Wisconsin. The largest margin is found in the Northeast region, where New York has over 100 times the potential renewable energy resources as the state with the fewest resources, Rhode Island. As EPRI states, "EPA's 'best practices' scenario for developing state-specific renewable energy targets assumes state equivalency for regional calculations of resource potential. This assumption is problematic when regions are large and encompass states with appreciably different renewable energy resources."[351] EPA attempt to group such disparate states into regions thus lacks a rational basis.

3. The concept EPA sets forth in the NODA does not make EPA's building block three less approach does not make arbitrary.

The NODA recognizes that EPA's regional grouping of states is arbitrary and tries to address this issue by positing that states could be grouped together based on the "RE potential available across a multi-state region." Under this approach, a state's goal "would be informed" by the state's "opportunity" to develop out-of-state resources in the region. EPA says one way this could be done is (1) using the regions set forth in the proposal; (2) for each region, summing each state's potential for renewable resources; and (3) "reallocating that summed generation proportionately to each state within that region by a chosen criterion, such as each state's share of total electricity within that region." EPA asks for comment on this idea, along with several sub-issues: (1) what the basis for the grouping would be; (2) the basis for reapportioning state renewable resource requirements within the region; and (3) whether all or only a portion of a

[351] EPRI Comments at 5.

state's renewable resource requirement should be reallocated (including whether existing hydropower should be reallocated).[352]

EPA's proposal, however, suffers from a number of flaws. First, as with the rest of the NODA, it is too inchoate for rational comment. The proposal sounds more like an advance notice or proposed rulemaking than an actual regulatory proposal. If EPA actually wishes to propose something along these lines, it should make an actual proposal.

Second, the concept is divorced from the original rationale of building block three that those state legislatures that adopted renewable portfolio standards established the "best practices" for renewable development. The NODA concept abandons that justification and now is based on presumably an EPA determination of the potential for renewable development in a region and an EPA mandate that states share in the economic cost of that development. This top-down approach to renewable development, however, is contrary to traditional state control of generation development.

Finally, the proposal does nothing to solve the fundamental problem that EPA does not have authority to order states to require their utilities to acquire any particular amount of renewable generation.

4. EPA misrepresents state portfolio standards.

In presuming to opine on "best practices" on renewable energy development, EPA misrepresents the standards that states have adopted. Although this information is not included in EPA's proposal or supporting documents, most state standards contain "off-ramps," where the state could acquire a lower amount of renewable resources than the numerical levels set forth in the standards depending on impacts on cost or grid reliability. These "off-ramps" also represent

[352] 79 Fed. Reg. at 64,551-52.

legislative choices that EPA ignores given its view that it should be the arbiter of "best practices" for renewable resource development.

For instance, a recent article noted that:

- 7 states have annual cost caps on utilities' annual revenue requirement for renewable resource development;
- 4 states have a retail rate impact limitation;
- 3 states cap the monthly surcharge on a customer's bill at a set amount;
- 13 states provide for payment into a fund as an alternative compliance mechanism;
- 3 states subject renewable resources to review under a just-and-reasonable standard;
- Virtually every state with a portfolio standard has some other form of off-ramp, such as a waiver or a freeze, depending on compliance impacts.[353]

EPA's "best" system, however, ignores these off-ramps.

EPA also does not account for the fact that states define renewable resources that are subject to their portfolios differently than EPA. For instance, North Carolina's portfolio standard drives EPA's building block three requirements for the southeastern states. But EPA fails to recognize that North Carolina's portfolio standard can be satisfied either by renewable resources or demand-reduction programs.[354] As NERC noted, if the North Carolina energy efficiency part of the portfolio standard "were properly excluded by the EPA, [it] would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii."[355]

Other examples of EPA misrepresenting state renewable portfolio standards abound, as other commenters will show. As NERC reported, "[a]s an example, New York has an RPS

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[353] Gabriella Stockmayer, Vanessa Finch, Paul Komor, Rich Mignogna, LIMITING THE COST OF RENEWABLE PORTFOLIO STANDARDS: A REVIEW AND CRITIQUE OF CURRENT METHODS, Energy Policy 42 (2012) 155-163.
[354] N.C. Rev. Stat. § 62-133.8(b).
[355] NERC Report at 12.

percentage of 30 percent. According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables. New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.[356]

Another example given by NERC is EPA's failure to recognize "[m]ultipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources. Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable."[357]

In sum, EPA's approach, by definition, is arbitrary.

5. EPA failed to account for the fact that most portfolio standards do not apply to municipal and cooperative utilities.

EPA fails to account for the fact that municipal and cooperative utilities typically are exempt from portfolio standards.[358] For instance, although Montana has a 15% RPS, that standard does not apply to consumer-owned utilities, to public power projects, or to generators owned by out-of-state utilities.[359] As a result, Montana's RPS is far lower than EPA assumes. EPA thus has no basis to cite state portfolio standards in proposing regulations that would encompass municipal and cooperative load.

6. EPA failed to account for the fact that most portfolio standards may be satisfied with out-of-state power.

[356] *Id.* (footnotes omitted).
[357] *Id.* (footnotes omitted).
[358] See APPA, "State Renewable Portfolio Standards Applicable to Public Power," July 2012; SOURCEWATCH, "Renewable Portfolio Standard,"available at http://www.sourcewatch.org/index.php/Renewable_portfolio_standard.
[359] Kavulla Testimony at 11-12.

States portfolio requirements typically can be satisfied with renewable energy generated in other states. This evinces a legislative recognition that it may be economically preferable for a state not to import some or all of the resources needed to meet the in-state mandate. This principle, however, is lost in EPA's vision of renewable energy "best practices." For instance, by assigning state X an initial renewables goal of, for instance, 10 percent based on that state's portfolio standard of that amount, EPA is concluding that the "best" system for that state entails *in-state* generation of 10 percent renewables. Accordingly, EPA's goal assumes the state will develop the necessary amount of renewable resources in-state. But state X's legislature, in allowing the portfolio standard to be met with out-of-state generation, did not conclude that generating in-state renewable energy at 10 percent represents wise public policy. To the contrary, the legislature may have assumed that most of the mandated renewable generation would be imported. Thus, EPA is arbitrarily using state legislation to set an in-state renewable target that the legislation itself did not set.

7. EPA failed to account for the transmission that must be built to accommodate the amount of renewable resources it projects.

EPA's assumption that large amounts of renewable power can be developed and brought to market within the proposal's compliance time lines fails to account for the significant cost and time needed to build the necessary transmission. As FERC has stated, "…increased adoption of [renewable portfolio standard measures] has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus [increase the] need for transmission to access remote resources …."[360] As a result, "additional, and potentially

[360] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 46, 497 (2011) (Order No. 1000), order on reh'g, Order No. 1000--A, 139 FERC ¶ 61,132 (Order No. 1000--A), order on reh'g, Order No. 1000--B, 141 FERC ¶ 61,044 (2012) (Order No. 1000--B).

significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation."[361]

At the same time, however, building new transmission is costly and time consuming, as is discussed in more detail below. EPA, however, does not include any information in its proposal as to the cost or time needed to build transmission. EPA simply assumes that the needed renewable resources will become available when needed. That assumption is arbitrary.

8. EPA failed to consider numerous additional factors that affect the cost and reliability-impacts of building block three.

The NERC report sets forth numerous factors that EPA should have but did not consider:

- "The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited."[362]

- "The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources."

- "There is also the implicit need to increase ancillary services as a result of the increased variable resource output."[363]

- "[T]here are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements."[364]

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[361] *Id.*
[362] NERC Report at 12-13.
[363] *Id*. at 13.
[364] *Id.*

9. EPA irrationally assumed that states could begin increasing renewable generation by 2017.

EPA's calculation of the amount of renewable generation it believes each state can build is based on the assumption that states begin increasing renewable generation in 2017.[365] This assumption is irrational. Even if states do not obtain a one-year or two-year extension of EPA's one-year deadline for submitting plans, states would not submit their plans until June 2016 and EPA would not approve them until June of 2017. It takes years to site, permit and build renewable construction and, if new transmission is needed, which is highly likely, 8-10 years to site, permit and build the transmission. EPA doesn't even attempt to explain how, in response to the rule, states could begin increasing their renewable resources in 2017.

F. Building Block Three as to Increased Nuclear Generation Is Arbitrary and Unsupported.

Other commenters will explain why EPA's analysis of nuclear power is arbitrary and unsupported. NMA highlights two points.

First, EPA's assumption that "at risk" nuclear generation will continue to operate is unsupported.[366] This generation is obviously "at risk" for a reason, yet EPA does not examine why this generation is at risk or what impediments would have to be removed in order for this generation to keep operating. For example, Exelon, the largest owner of nuclear power in the United States, has warned that the United States nuclear fleet is aging and faces severe challenges in avoiding large-scale closures in the future.[367] Exelon is also taking the public position that nuclear power has become unprofitable in light of low natural gas prices and subsidized wind power and that three of its six Illinois nuclear plants are "on the bubble" of

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[365] GHG Abatement Measures TSD at 4-2.

[366] GHG Abatement Measures TSD, Ch. 4.4.

[367] Exelon, Bipartisan Policy Center presentation, GHG REGULATION OF EXISTING POWER PLANTS, Dec. 6, 2013, available at http://www.exeloncorp.com/performance/policypositions/overview.aspx#section_3.

closing.[368] EPA, however, simply assumes that these types of impediments can be removed without explaining why.

EPRI explains the fallacy of EPA's approach:

> EPRI urges EPA to consider the lifetime of existing nuclear units where many units will reach their 60-year license limit by 2029. Three units with licenses scheduled to expire prior to 2030 are already in their extended period of operation and would need to obtain additional license extension to extend their operating lives to 80 years (known as subsequent license renewal). Though it is expected that many reactors will apply for and receive license extensions out to 80 years, there is no level of certainty at this time.
>
> There is significant uncertainty as to whether the Nuclear Regulatory Commission (NRC) will extend the operating licenses for each nuclear unit as assumed. License renewal is a long and multifaceted process which is based on submittals of complex studies to the NRC and its detailed review.[369]

Indeed, EPA performs almost no analysis at all. The extent of EPA's analysis is (a) an EIA estimate that 5.7 GW of existing nuclear capacity is likely to be lost, (b) an article by two EIA analysts that referred to this reduction in capacity as occurring because of "continued economic challenges," and (c) a February 2013 Credit Suisse report that nuclear units may be experiencing up to a $6 MWh shortfall in covering their operating costs.[370] EPA translates these speculations into the conclusion that at a $12-$17 carbon price, a price EPA finds reasonable, this capacity would continue to be available. To characterize this analysis as scanty understates the point. One quotation from one brief article by two EIA analysts plus a cherry-picked quotation from a single 23-page investment report hardly qualifies as "substantial evidence" that all at risk nuclear generation can be preserved. Indeed, even a cursory glance at the Credit

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368 Chicago Tribune, Exelon seeking compensation for nuclear plants, July 31, 2014, available at http://www.chicagotribune.com/business/breaking/chi-exelon-seeking-compensation-for-nuclear-plants-20140731-story.html.

369 EPRI Comments at 5.

370 GHG Abatement Measures TSD at 4-33 – 4-34.

Suisse article indicates that the nuclear industry faces issues that are more than merely monetary, including a large number of aging units experiencing very high levels of service outages.[371]

Second, having utilized EIA's figure of 5.7 GW of nationwide nuclear capacity that is likely to be lost, and having determined that this number represents about 6 percent of nationwide nuclear power, EPA then arbitrarily assumes that 6 percent of every state's nuclear power is at risk and can be saved.[372] EPA has no basis for making this assumption. Specific nuclear units in specific states are at risk of retirement or derating. Others are not. As an example, Arkansas Electric Cooperative Corporation reports that no nuclear generation is at risk in Arkansas, yet EPA's inclusion of that assumption in calculating Arkansas' goal artificially makes that goal more stringent.[373] There is thus absolutely no reason to assume that because one state has nuclear generation at risk, every other state that has nuclear generation has the same proportion of nuclear generation at risk. EPA's assumption that they do is the definition of arbitrary.

Moreover, EPA's six percent assumption has the absurd result that the amount of nuclear generation to be "saved" in meeting the state's rate goal is less than the smallest nuclear reactor in any state. For example, Texas is assigned 290 MW of at-risk capacity, while the smallest unit in the state is 1195 MW, four times as large. To match its goal, Texas would need to determine somehow that 24 percent of the capacity of its smallest unit was "at risk" and that it had taken some measures to retain it in operation.

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[371] Eggars, et al., "Nuclear…The Middle Age Dilemma?," Credit Suisse, February 2013.

[372] GHG Abatement Measures TSD at 4-33 – 4-34.

[373] Arkansas Electric Cooperative Corporation, Comments on U.S. Environmental Protection Agency (EPA) Proposed Rule on Greenhouse Gas Emission from Existing Stationary Sources: Electric Utility Generating Units (Clean Air Act Section 111(d)), available at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CCAQFjAA&url=http%3A%2F%2Fwww.adeq.state.ar.us%2Fair%2Fbranch_planning%2Fpdfs%2Fcarbon_pollution%2Fcp_i_general_comments_of_aecc_on_the_cpp.pdf&ei=HMkAVO3HJoTIggT1poKwDg&usg=AFQjCNGCvw4kyuOBzmFs2sgVHX_uYsVwbg&bvm=bv.74115972,d.eXY.

Nor does EPA have a rational basis to conclude that new nuclear generation will come on line as scheduled. Indeed, witnesses for the staff of the Georgia Public Service Commission recently testified that the already-delayed Plant Vogtle faces further delays and indeed lacks an integrated project schedule beyond 2015.[374]

G. Block 4 Is Arbitrary and Unsupported.

Other commenters will examine the many arbitrary assumptions underlying EPA's fourth building block. For instance, EPRI, which has researched potential power sector energy efficiency in great depth, warns that EPA has far overstated the amount realistically achievable.[375] The NERC report sets forth a complete critique of EPA's building block four assumptions, showing that EPA misread the studies it relied on and far overstated the potential for energy efficiency.[376] As NERC stated, EPA's conclusion that states can make and sustain the energy efficiency measures EPA relies on "is not supported by any peer reviewed or technical studies of energy efficiency potential."[377] As NERC concluded,

> By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.

NMA points out the two most glaring flaws.[378]

NMA notes several additional points.

[374] Direct Testimony of Steven D. Roetger and William R. Jacobs, Jr. before the Georgia Public Service Commission, Docket No. 29849, Nov. 21, 2014.
[375] EPRI Comments at 6.
[376] NERC Report at 14-16.
[377] *Id*. at 15.
[378] *Id*. at 16.

First, as with EPA's renewable energy discussion, EPA presumes to dictate "best practices" to states for energy conservation programs.[379] But, as with renewable energy, EPA neither has the expertise nor the authority to dictate to states what "best practices" are for adopting programs that conserve energy. As a Montana public utility commissioner recently testified:

> Each state's utility commission of which I am aware has evaluated the potential energy savings available to the utilities it regulates, and the possibilities depend on many variables, from climate of the region, to the hours of daylight at the particular latitude, to the mix of consumers (industrial versus residential) served by the utilities. That is why each state has a utility commission, and why it makes sense to house this kind of decision-making at the state or local level, and not in a federal agency. Unfortunately, Building Block 4 is perhaps the banner example of the BSER's supposition of an arbitrary target that lacks meaningful substantiation in the real world. The Public Service Commission in Montana (and the comparable agency in many other states) already obligates the utilities that it regulates to acquire all cost-effective energy efficiency available to them. The EPA's rule supposes that there is a substantial amount beyond this available for the taking. This assumption is only thinly evidenced in the EPA's rule.[380]

Indeed, some state public service commissions, such as Florida's, based on their own considerably more informed and in-depth analyses than EPA has performed, are *reducing* their energy efficiency targets.[381]

Second, EPA cannot meet the statutory standard of showing that its energy efficiency projections have been "adequately demonstrated." Indeed, the sheer magnitude of EPA's energy efficiency goals is staggering. EPA projects that in 2030, electricity usage will be 10 percent below the business-as-usual case.[382] According to EPA, electric consumption in 2030 will be

[379] 79 Fed. Reg. at 34,872.
[380] Kavulla Testimony at 14.
[380] *See* Resource Adequacy and Reliability Analysis TSD.
[381] EnergyWire, "Fla. regulators slash efficiency goals for utilities," November 26, 2014.
[382] GHG Abatement Measures TSD at 5-48, Table 5-21.

little more it is today and will actually decline between 2020 and 2030.[383] According to the U.S. Census, population is expected to rise to 358,471,000 people by 2030, an increase of 37,108,000 from the projected 2015 level of 321,363,000, or an average of more than 2 million people per year.[384] Although economic growth has been slow-paced, presumably at some point in the next 15 years, it will pick up to more normal rates of growth. EPA's proposal thus assumes that the country's population and economy can grow without electricity growth. There is no precedent to back up this extraordinarily aggressive assumption. NERC disbelieves it. NERC examined various load growth projections and energy efficiency program data that it collects for its annual grid reliability assessments. This data shows far lower efficiency gains than EPA projects. As NERC concluded, "the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts."[385]

Indeed, there is no national-level precedent for EPA's highly aggressive assumptions as to the amount of electricity that can be saved year-over-year based on energy efficiency measures. EPA reports that states have implemented energy efficiency programs for decades, that all states fund energy efficiency in some measure, and that state funding for energy efficiency has rapidly increased.[386] Yet EPA is forced to concede that, for its primary option, only three states have actually achieved, for some period, the level of savings that EPA projects for all states. Only another nine states have even targeted (but not achieved) that level.[387] This

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383 *See* Data File: GHG Abatement Measures Scenarios 1 and 2 (3,773,750 GWh of consumption in 2014, rising to only 3,792,371 GWh in 2030). *See also* Energy Ventures Analysis, "EPA Clean Power Plan, Costs and Impacts on U.S. Energy Markets," August 2014.

384 http://www.census.gov/population/projections/data/national/2012/summarytables.html, Table 1, middle series projection.

385 NERC report at 16.

386 *Id*. at 5-2.

387 79 Fed. Reg. at 5-33.

falls far short of evidence "adequately demonstrating" the ability of all states to meet EPA's target.

Moreover, in contrast to EPA's projection that, under building block 4, electricity usage in 2030 would be little higher than electricity usage today and would decline between 2020 and 2030,[388] even the states that EPA says have achieved the level of demand-side savings that EPA projects have not been able to prevent electricity consumption from growing over time nor do they project zero or negative load growth in the future. With the exception of recessions, California's electricity consumption has always grown and it is projected to continue growing in the future.[389]

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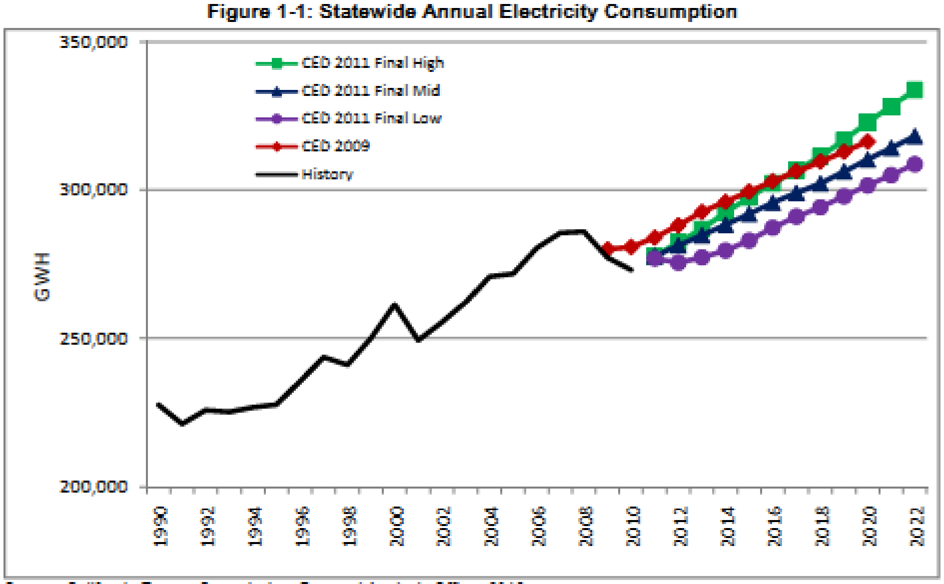
Figure 1-1: Statewide Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

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[388] *See* Data File: GHG Abatement Measures Scenarios 1 and 2 (3,773,750 GWh of consumption in 2014, rising to only 3,792,371 GWh in 2030); Energy Ventures Analysis, "EPA Clean Power Plan, Costs and Impacts on U.S. Energy Markets," August 2014.

[389] *See* California Energy Commission, "California Energy Demand, 2012-2022 Final Forecast, Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency," June 2012, Figure 1-1, p.14.

Similarly, ISO New England's most recent forecast projected that the region's overall electricity demand would grow at a rate of 1.1% annually over the next decade.[390]

Third, EPA's claim as to the cost-effectiveness of the energy efficiency measures it relies on is belied by the fact that the IPM model projects that electricity consumption will continue to grow, even with the rule in place. As EPA says, "the degree to which EE is employed as an abatement resource is not determined endogenously within the power sector modeling based upon optimization of costs but, rather, 'hard wired' into the illustrative compliance scenarios."[391] If the energy efficiency measures truly were cost-effective, however, it would not be necessary to "hard wire" them into EPA's projections.

Fourth, EPA makes an inherently arbitrary adjustment to the way it accounts for a state's energy efficiency measures in setting the states' carbon intensity goals. EPA first determines the amount of electricity it believes each state should save and then multiplies that amount by the percentage of a state's total electric consumption that the state generates in state. Thus, in the example EPA gives, Ohio is presumed to save 18,942,382 MWh and "[t]his value is then multiplied by 85.97% (Ohio's share of sales coming from in state power generation) to reflect the amount of avoided in-state generation that results from the energy efficiency investments."[392]

This adjustment is arbitrary and serves no valid purpose. States that generate the most coal power, such as Wyoming, Montana, West Virginia and Kentucky, tend to be states that are small in population and therefore export a great deal of the coal power they generate. There is therefore little connection between the amount by which these states may reduce their electricity consumption and the amount of coal power these states will generate.

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[390] ISO New England, 2013 Regional System Plan, available at http://www.iso-ne.com/system-planning/system-plans-studies/rsp, p. 33, Table 3-1.

[391] *Id*. at 5-49.

[392] Goal Computation TSD at 18.

This adjustment also obviously creates wide disparities in setting state goals given that different states import and export different amounts of power. The adjustment requires states that consume all or most of the power they generate to reduce electric consumption more than states that import a greater amount of their power. Yet, in an integrated grid, there is no reason why a state should wish to generate more or less power in-state; how much a state should rely on in-state power should depend on interstate power economics. As previously discussed, the entire thrust of federal electricity policy over the last two decades has been to break down artificial barriers and open up the power grid to the free movement of electrons so that consumers have the benefit of the lowest cost sources of electricity wherever those sources are located. Indeed, EPA's policy of promoting renewable energy depends on promoting large-scale, long-distance electric transmission, as the areas richest in renewable resources (for instance in the Midwest wind belt) are not located near to the nation's major metropolitan areas. It therefore makes no sense to set state goals in part based on their percentage of in-state generation or to create an incentive for states to increase their use of in-state generation.

In addition, EPA's adjustment is arbitrary because it fails to account for all of the CO_2 emissions reductions that will be created by the enormous amount of energy efficiency that EPA is assuming. In EPA's Ohio example, for instance, 14.03% of Ohio's saved electricity is not counted against *any* state's goal, yet all of Ohio's reduced consumption would avoid electric generation (and thus presumably CO_2 emissions) somewhere. Presumably, that 14.03% savings should be credited to the states which purchase power from Ohio. But EPA never performs that calculation nor would it be feasible to do so on a 50-state basis given the dynamics of the interstate electricity market. In the end, EPA's attempt to superimpose state-by-state energy efficiency targets on the interstate grid thus cannot help being arbitrary.

H. EPA's Guidance for Converting the Proposed Rate-Based State Goals to Mass-Based Goals Arbitrarily Makes the Rule More Stringent.

On November 6, 2014, EPA issued a technical support document offering guidance for states to convert EPA's rate-based goals to mass-based goals (EPA's "Conversion Guidance").[393] The Conversion Guidance recognizes on page 1 that the formula for converting a rate-based goal into a mass-based goal simply requires the multiplication of the emission rate goal by a specific generation level to determine mass emissions. However, EPA's Conversion Guidance uses a different generation level than EPA assumed in its original rate-based proposal, which results in far more stringent goals.

Specifically, EPA's original proposal relied on an equation that determined generation by adding incremental renewable generation, nuclear generation, and energy efficiency improvements to 2012 generation. However, the primary option in EPA's Conversion Guidance utilizes 2012 generation alone—without any incremental changes—to calculate a mass-based goal. Although EPA's guidance contains several complicated formulae, the variables in those formulae cancel each other out.[394] Without the incremental generation changes accounted for in EPA's original rate-based proposal, the mass-based goal relies on a lower generation value, thus resulting in a lower mass-based goal than would be expected if the goal were truly equivalent to EPA's rate-based goal.

Because EPA's Conversion Guidance requires the calculation to be made based on 2012 generation alone, instead of the generation relied upon in EPA's original proposal (2012 generation plus incremental changes), EPA mass-based interim limitation for the affected units is

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[393] Technical Support Document, "Translation of the Clean Power Plan Emission Rate-Based CO2 Goals to Mass-Based Equivalents," Nov. 6, 2014.

[394] The only variables that do not cancel out are new generation from under-construction nuclear or natural gas combined cycle units, which only applies to twelve states. But even in those states, the generation relied upon in setting the rate-based goals is still higher than what EPA has proposed in its Conversion Guidance, resulting in more stringent mass-based goals as compared to the rate-based goals.

214,771,000 metric tons more stringent than the tonnage limitation used in the EPA rate-based calculation. The final limitation for affected units is also 308,867,000 metric tons more stringent than the mass emissions used in the final state rate-based calculation. As a result, EPA has arbitrarily changed its calculations to set an even lower limit than EPA calculated as BSER. The chart below shows the increase in emission-reduction requirement from a rate-based approach to a mass-based approach.

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CO2 Mass Limits Comparison for Affected Units ONLY (Thousand Metric Tons)

State	Original CO2 Emissions used in ER Calculation	EPA Proposed Mass Equivalents Interim (Avg. '20-'29)	EPA Proposed Mass Equivalents Final (2030-)	Original CO2 minus Interim	Original CO2 minus Final	% Difference Original CO2-Interim	% Difference Original CO2-Final
Alabama	60,019	54,441	50,267	5,578	9,752	-9.3%	-16.2%
Alaska	1,796	1,593	1,457	203	339	-11.3%	-18.9%
Arizona	21,295	18,559	17,734	2,736	3,561	-12.8%	-16.7%
Arkansas	23,372	21,384	20,096	1,988	3,276	-8.5%	-14.0%
California	44,113	37,052	35,805	7,061	8,308	-16.0%	-18.8%
Colorado	30,514	26,495	25,335	4,020	5,179	-13.2%	-17.0%
Connecticut	5,788	4,712	4,265	1,076	1,523	-18.6%	-26.3%
Delaware	3,520	3,226	2,972	294	548	-8.3%	-15.6%
Florida	81,293	73,209	68,221	8,084	13,072	-9.9%	-16.1%
Georgia	46,234	33,850	31,676	12,383	14,558	-26.8%	-31.5%
Hawaii	4,644	4,232	4,010	412	634	-8.9%	-13.7%
Idaho	638	472	468	167	170	-26.1%	-26.6%
Illinois	74,263	62,868	58,471	11,395	15,792	-15.3%	-21.3%
Indiana	84,596	76,689	73,090	7,906	11,506	-9.3%	-13.6%
Iowa	29,129	26,554	25,749	2,576	3,381	-8.8%	-11.6%
Kansas	29,356	25,346	24,081	4,010	5,275	-13.7%	-18.0%
Kentucky	78,413	73,409	70,203	5,003	8,209	-6.4%	-10.5%
Louisiana	31,677	28,808	26,823	2,868	4,853	-9.1%	-15.3%
Maine	1,581	1,377	1,323	204	258	-12.9%	-16.3%
Maryland	16,854	13,186	11,613	3,669	5,242	-21.8%	-31.1%
Massachusetts	10,549	8,435	7,414	2,114	3,135	-20.0%	-29.7%
Michigan	52,638	45,868	43,403	6,770	9,235	-12.9%	-17.5%
Minnesota	17,283	15,106	14,474	2,176	2,809	-12.6%	-16.3%
Mississippi	19,232	17,397	16,449	1,836	2,783	-9.5%	-14.5%
Missouri	62,942	58,558	55,792	4,384	7,150	-7.0%	-11.4%
Montana	15,307	13,630	12,828	1,677	2,479	-11.0%	-16.2%
Nebraska	22,114	19,577	18,142	2,537	3,972	-11.5%	-18.0%
Nevada	11,366	9,915	9,209	1,451	2,157	-12.8%	-19.0%
New Hampshire	3,304	2,541	2,262	763	1,042	-23.1%	-31.5%
New Jersey	10,296	8,213	6,741	2,083	3,555	-20.2%	-34.5%
New Mexico	12,667	10,977	10,391	1,690	2,276	-13.3%	-18.0%
New York	26,595	20,415	17,649	6,180	8,946	-23.2%	-33.6%
North Carolina	46,430	40,068	36,918	6,362	9,511	-13.7%	-20.5%
North Dakota	28,457	27,577	27,069	880	1,388	-3.1%	-4.9%
Ohio	85,944	74,614	68,751	11,329	17,193	-13.2%	-20.0%
Oklahoma	36,342	32,133	30,892	4,209	5,450	-11.6%	-15.0%
Oregon	5,486	3,952	3,614	1,534	1,873	-28.0%	-34.1%
Pennsylvania	95,682	81,022	72,272	14,660	23,410	-15.3%	-24.5%
Rhode Island	3,389	3,072	2,924	317	465	-9.4%	-13.7%
South Carolina	27,536	17,218	15,816	10,317	11,719	-37.5%	-42.6%
South Dakota	1,948	1,731	1,602	217	346	-11.1%	-17.7%
Tennessee	33,371	24,624	22,837	8,746	10,533	-26.2%	-31.6%
Texas	168,258	146,705	135,937	21,553	32,321	-12.8%	-19.2%
Utah	23,260	21,244	20,384	2,015	2,876	-8.7%	-12.4%
Virginia	24,470	20,650	18,923	3,820	5,548	-15.6%	-22.7%
Washington	3,891	2,728	2,862	1,163	1,030	-29.9%	-26.5%
West Virginia	61,693	56,814	52,636	4,879	9,056	-7.9%	-14.7%
Wisconsin	31,252	26,916	25,275	4,337	5,978	-13.9%	-19.1%
Wyoming	42,786	39,649	37,590	3,137	5,196	-7.3%	-12.1%
US Total	**1,653,582**	**1,438,811**	**1,344,715**	**214,771**	**308,867**	**-14.5%**	**-20.0%**

EPA's Conversion Guidance does contain a second option that may be intended to allow for the use of a more appropriate generation level in determining mass-based goals by including a growth factor. However, that approach still is not equivalent to the generation level utilized in EPA's original proposal, and therefore does not result in "equivalent" goals, which EPA claims are necessary for states to employ the mass-based option. In addition, EPA's Conversion Guidance seems to suggest that a growth factor would only be appropriate if states require newly constructed units to fall under the mass-based goal as well, something that the CAA clearly forbids.[395] Furthermore, EPA's growth factors are low; if growth is higher than EPA projects, the mass-based limits will again be overly stringent. Therefore, even the second option of EPA's Conversion Guidance is arbitrary.

IX. EPA's BSER Analysis Failed to Consider Important, Relevant Factors.

EPA is obligated under a variety of statutes and Executive Orders to conduct a detailed analysis of the effect its proposal will have not just on the direct target of the regulation but on society as a whole.

First, under Section 111(a), a BSER analysis must "tak[e] into account the cost of achieving" the emission reduction that the BSER would produce "and any nonair quality health and environmental impact and energy requirements." The D.C. Circuit has been crystal clear that these considerations necessitate consideration of the impacts of BSER on a broad-economy-wide basis. In *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981), *rev'd on other grounds,* 463 U.S. 680 (1983), the court stated that "[t]he language of section 111 . . . gives EPA authority . . . 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

[395] Section 111(a) defines "new sources" and "existing sources" to be mutually exclusive, and Section 111(b) only applies to new sources, while Section 111(d) only applies to existing sources.

immediate present." Examining the legislative history of Section 111, the court stated that a Section 111 analysis requires "a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems." *Id.* at 331. The court concluded that EPA "must examine the effects of technology on the grand scale in order to decide which level of control is best." *Id.* at 330.

Indeed, even before the 1977 CAA Amendments, which added the phrase "and any nonair quality health and environmental impact and energy requirements," the D.C. Circuit considered the required BSER analysis to be extremely broad. In *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 384 (D.C. Cir. 1973), the court held that EPA was not required to prepare an environmental impact statement under the National Environmental Policy Act because "section 111 of the Clean Air Act, properly considered, requires the functional equivalent of a NEPA impact statement."

The D.C. Circuit has also held that EPA's analysis must be deep as well as broad. In *National Lime Ass'n v. EPA*, 627 F.2d 416, 429 (D.C. Cir. 1980), the court noted the "rigorous standard of review under section 111" applied by reviewing courts. The court stated that the "sheer massiveness of impact of the urgent regulations," considered in that and other cases had "prompted the courts to require the agencies to develop a more complete record and a more clearly articulated rationale to facilitate review for arbitrariness and caprice" than might otherwise apply. *Id*. at 451 n.126.

These considerations apply with even more force to the present rulemaking. The potential economy-wide impacts involved in *Costle, Portland Cement, and National Lime* were far more limited than they are here. In those cases, EPA determined the appropriate control technology for new facilities in the Portland cement, electric generation, and lime industries should install to control traditional emissions. Here, EPA has decided that, in order to dramatically reduce power-sector GHG emission reductions, grid operations should be completely redesigned, a result that will be many time more impactful than the performance standards for new facilities in *Costle, Portland Cement, and National Lime*. Moreover, the need for an adequate record here is even more critical because, as discussed above, a court cannot rely on and hence will not defer to EPA's presumed technical expertise.

Second, Section 317(b) of the CAA provides that "[b]efore publication of notice of proposed rulemaking with respect to any standard or regulation to which this section applies [including standards under Section 111], the Administrator shall prepare an economic impact assessment respecting such standard or regulation." EPA is required to include that assessment in the rulemaking docket. The assessment must include:

> (1) the costs of compliance with any such standard or regulation, including extent to which the costs of compliance will vary depending on
>
> > (A) the effective date of the standard or regulation, and
> >
> > (B) the development of less expensive, more efficient means or methods of compliance with the standard or regulation;
>
> (2) the potential inflationary or recessionary effects of the standard or regulation;
>
> (3) the effects on competition of the standard or regulation with respect to small business;
>
> (4) the effects of the standard or regulation on consumer costs; and
>
> (5) the effects of the standard or regulation on energy use.

Third, Section 321 requires EPA to conduct ongoing assessments of the employment effects of its actions.

Fourth, a number of other statutes and rulemakings also require a broad analysis by EPA. For instance, Executive Orders 12866 and 13563 require EPA to fully document the costs of the rule. The Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. § 601 et seq., requires EPA to assess the impact of the rule on small entities. Title II of the Unfunded Mandates Reform Act of 1995, Public Law 104-4 requires EPA to assess the impact of the rule on state, local and tribal governments. And Executive Order 13211 requires EPA to prepare a Statement of Energy Effects for rules, such as this one, that constitute "significant energy actions."

Taken together, these authorities require EPA to undertake an extensive analysis of the impact its regulation will have. EPA failed to do so. Specifically: (1) EPA improperly failed to include in the record most of the IPM model runs that EPA conducted; (2) EPA seriously underestimated the cost of compliance with the rule and its impact on consumer electricity and natural gas prices; (3) despite mounting concerns from reliability coordinators, EPA failed to undertake a true reliability analysis and ignores the damage the rule will do grid reliability; (4) EPA's analysis of the price and availability of natural gas fails in numerous respects; (5) EPA failed to examine the public health and welfare harms that its regulations will cause by raising electric rates; (6) EPA failed to examine impacts cumulatively with EPA's other regulations; (7) it failed to consider the impact its regulations will have on utility stranded investment; (8) EPA significantly overstated the benefits of the rule; (9) EPA's life-cycle analysis is flawed; (10) EPA failed to consider the environmental impacts of displacing coal generation with other generation sources; and (11) EPA failed to consider factors that will prevent states from submitting plans on EPA's timeline. Each of these failings renders EPA's proposal arbitrary.

A. EPA Improperly Failed to Include in the Record the Relevant Information for Most of the IPM Model Runs that It Conducted.

EPA's analysis of the effects the proposed rule will create consists primarily of IPM model runs. These runs form the basis for EPA's RIA, and they are a key component of the

Agency's conclusion that EPA's "best system" and the standards it is imposing as a result of that system are achievable. Yet despite the centrality of these model runs to EPA's analysis, and despite the fact that the Agency conducted 25 different model runs, it (a) failed to include the complete model run information for any years it modeled, (b) included in the record the parsed files for only 4 out of the 25 model runs, and (c) did not include any information for model runs simulating 2030, the key compliance date for the rule.[396] EPA's failure to include this information is a plain violation of Section 317 and of the Agency's obligation under Section 307(d)(5) to create an adequate record and provide the public with an opportunity for notice and comment.

B. EPA Seriously Underestimates the Cost of Complying with the Rule and the Impact of the Rule on Consumer Electricity and Natural Gas Prices.

EPA estimates direct annual compliance costs of $5.4-$7.4 billion in 2020, declining to $4.6-$5.5 billion in 2025, and rising to $7.3-$8.8 billion in 2030.[397] This is far too low. For instance, MISO, estimated that, just in the MISO region, the 20-year discounted compliance cost would be $55-$83 billion, *even without considering the significant amount of transmission and natural gas pipeline development that the rule will make necessary and the billions of dollars in stranded pollution-control investments that the rule will create*.[398] ERCOT forecasts 20% retail rate increases by 2020, "without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT.[399] The Kansas Corporation Commission estimated $5-$15 billion in compliance costs,

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396 *See* August 25, 2014 letter from 13 state Attorneys General to EPA; September 3, 2014 letter of Utility Air Regulatory Group to EPA.

397 RIA, at ES-8, Table ES-4.

398 MISO, GHG Regulation Impact Analysis – Initial Study Results, September 17, 2014 (attached hereto).

399 ERCOT, "Analysis of the Impacts of the Clean Power Plan," November 17, 2014 (ERCOT Report), at 1(attached hereto).

with a corresponding electric rate increase of between 10% and 30% over 13 years.[400] The Virginia State Corporation Commission estimates that just one utility will experience compliance costs with a present value of between \$5.5 and \$6.0 billion.[401]

Energy Ventures Analysis (EVA), a leading energy consulting firm for the utility, power transmission, natural gas, coal and renewable energy industries, undertook an analysis of the impact of the rule.[402] It found that for the ten-year period of 2020-2030:

- Wholesale electricity costs will increase by \$274 billion;
- Non-power natural gas costs will increase by \$ 80 billion;
- Additional capital costs for replacement power will be \$53 billion.

EVA also did not include in its analysis the tremendous investments in natural gas pipeline and electric transmission the rule will require. EVA's analysis modeled the mass-based option proposed in the rule—the option that many states may choose since it is simpler and less costly to implement than the rate-based option. Forty-four states will see double-digit increases in their wholesale power prices, with 24 states facing increases close to or in excess of 20 percent. EVA used the Aurora hourly economic dispatch model that calculates the lowest cost resource mix for each hour to simulate the operations of each power market. EVA's analysis also concluded that many of the underlying assumptions in EPA's four building blocks were not either economically or technically feasible.

The well-respected economic consulting and analysis firm, NERA, also undertook a detailed examination of the impact of the proposal. NERA's examination modeled the rate-based option proposed in the rule. It concluded that the proposal is the mvost expensive

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400 Comments on the proposed rule of the Kansas Corporation Commission at 28.
401 Comments of Virginia State Corporation Commission at 3.
402 Energy Ventures Analysis, "EPA Clean Power Plan, Costs and Impacts on U.S. Energy Markets," October 2014 (attached hereto).

environmental regulation ever imposed on the electric power sector, costing at least $41 billion per year. NERA also projected annual costs of $73 billion under a scenario that assumes that states do not have authority to undertake all four building blocks but would have to obtain their emission reductions through building blocks one and two. NERA projected the total cost of the EPA proposal to be $366 billion to $479 billion over a 15-year period. It found that EPA's proposal will cause double-digit electricity rate increases in 43 states. Nationwide, the EPA proposal will cause a 12% to 17% average increase in electricity prices. Fourteen states face peak year electricity price increases that could exceed 20%. NERA also did not include pipeline and transmission costs.[403]

In sum, notwithstanding EPA's insistence that the proposal embodies flexibility, as both the EVA and NERA analysis demonstrate, there are no low cost options under the agency's costly power plan.

C. EPA's Analysis of the Impact Its Proposal Will Have on the Reliability of the Power Grid Is Seriously Deficient.

A system of emission reduction that imperils the reliable operation of the grid is not a "best" system in any sense of the word. Yet entities with far more expertise in grid operations than EPA, including NERC, have warned that the EPA's proposal could lead to power outages and rolling blackouts. EPA, however, has failed to perform a real reliability assessment. Given the overwhelming evidence that EPA's proposal will endanger the grid, the proposal is arbitrary and capricious.

[403] NERA Economic Consulting, "Potential Energy Impacts of the EPA Proposed Clean Power Plan (NERA Report)," October 2014.

1. The grid is already close to the edge, EPA's MATS rule has made the situation worse, and the new proposal creates serious danger of blackouts and voltage collapse.

Recent events highlight the danger that EPA-forced retirements of coal generation is creating. As FERC Commissioner Moeller informed the Senate Energy and Natural Resources Committee:

> Our latest winter exposed an increasingly fragile balance of supply and demand in many areas. Prices at times were extraordinarily high. The experience of this winter strongly suggests that parts of the nation's bulk power system are in more precarious situation than I had feared in years past.[404]

According to Moeller, "the power grid is now already at the limit" with so many retirements of coal base load power plants and more to come as a result of EPA's MATs rule that takes effect in 2015.[405] FERC Chair Cheryl LaFleur agreed, stating that skyrocketing electricity and natural gas prices last winter brought the electric grid "close to the edge" of breaking on several occasions.[406]

John Sturm of the Alliance for Cooperative Energy Services informed FERC during its recent technical conference on winter grid performance, "[t]he unreliability of gas, wind and solar provided the lesson that fuel diversity is needed for reliability as well as for other policy reasons."[407] Coal-fired plant availability during the winter far exceeded gas-fired plant, wind and solar availability and provided much needed system stability and reliability. Nick Akins, Chairman & CEO, American Electric Power, testified that the "weather events experienced this

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404 *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Philip Moeller, FERC, p. 2 (April 10, 2014) available athttp://www.energy.senate.gov/public/index.cfm/files/serve?File_id=0174cd0a-9066-434c-aba4-e4ceb82cf444

405 *Id*.

406 Lynn Garner*, FERC Conference Highlights Problems of Using Natural Gas for Electric Generation* (BNA April 1, 2014). *See also* Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference (April 1, 2014) (transcript at 6) available athttp://www.ferc.gov/CalendarFiles/20140424112341-Transcript0401technical.pdf

407 John Sturm, Vice President, Alliance for Cooperative Energy Services, Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference, p. 6, (April 1, 2014) available athttp://www.ferc.gov/CalendarFiles/20140401084237-Sturm,%20ACES.pdf.

winter provided an early warning about serous issues with electric supply and reliability."[408] He noted that 89 percent of the coal capacity AEP will retire in 2015 due to EPA's MATS rule was called upon to meet electricity demand this winter.[409] Akins warned that this reliability concern is imminent and that EPA's Section 111(d) proposal will make matters worse.[410]

Similarly, Lynn Good, the CEO of Duke Energy, remarked that "[a]s I look at the portfolio we operate, which is a combination of coal and gas and nuclear and pump storage and hydro, we needed every bit of it."[411]Seventy-five percent of Southern Company's coal plants scheduled to close were needed.[412] TVA set new records for electricity demand as many of its coal-fueled generating facilities are scheduled for closure.[413]

During this period, the price of coal was stable while natural gas prices surged to all-time highs on the East Coast as well as other regions of the country. Natural gas prices rose to a high of $90mm/BTU at the delivery point in New Jersey on January 7, 2014. Trading hubs for South Carolina saw spikes to $95mm/BTU. Gas prices in some regions exceeded the equivalent of $500 per barrel of oil.[414] While it is certainly not unusual for natural gas prices to rise during the winter months, these prices are historic highs during a winter that was not as severe in terms of either cold temperatures or prolonged duration as the winter of 2004 that brought the previous highs of $58.52mm/BTU.[415]

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[408] *Id.* Statement of Nick Akins, p. 4 available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=366e6685-92f5-4878-a90f-253efa4495e8

[409] *Id*. at 2

[410] *Id*. at 4, 14

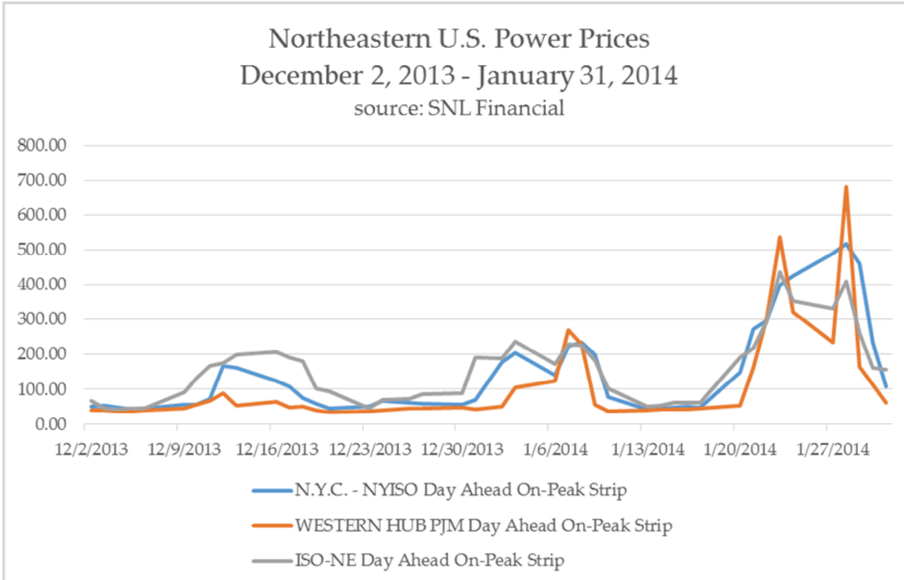
[411] Mark Chediak and Harry R. Weber, Polar Vortex Emboldens Industry to Push Old Coal Plants, Bloomberg, Mar 10, 2014.

[412] Chris Prandoni, Harsh Winter Reveals Necessity of Coal, Forbes, March 16, 2014.

[413] *Id.*

[414] EIA, Electric Power Monthly, February, March, 2014.

[415] *New York Spot Natural-Gas Prices Rise to Record as Cold Approaches*, Wall Street Journal, Jan. 6, 2014 available at http://online.wsj.com/news/articles/SB10001424052702303933104579304452246495282.



Electricity price spikes followed natural gas price increases that reached $2,000/MWh in the East and Midwest. In Texas, the heart of natural gas production, electricity prices reached a high of $5,000/MWh.[416] The Mid-Atlantic power pool incurred a cost of a half-billion dollars in additional payments to generators in order to keep the lights on for the 13-state region.[417] A less diverse electricity grid driven by policy-induced closures of coal power plants has been cited as a principal driver in the increase in electricity and natural gas prices.[418] Were it not for coal-fired base load power, the electric reliability and enormous price increases would have been far worse. Southern Company reported at the end of April its coal-fired generation increased during the first quarter of 2014 to 45 percent of its generation – a significant increase from 32 percent in the

[416] *Id.*
[417] Lynn Garner, FERC Conference Highlights Problems of Using Natural Gas for Electric Generation (BNA April 1, 2014).
[418] See, e.g., *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Philip Moeller, FERC, p. 2 (April 10, 2014) available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=0174cd0a-9066-434c-aba4-e4ceb82cf444.; Matthew Wald, Coal to the Rescue, but Maybe Not Next Winter, NY Times, March 10, 2014 available at http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0.

same period in 2013. Southern's natural gas-fired fleet generation dropped to 35 percent from 47 percent. Luckily, the fuel diversity of Southern's fleet allowed it to ramp up coal-fired generation and save its customers $100 million in the first quarter alone.[419]

A study performed for the NMA by EVA[420] showed how important the existing coal fleet was in maintaining grid reliability last winter. EVA found that had units that will now retire under the MATS rule not been available:

- There would have been 34 hours in PJM where the reserve margin was less than 5% and 4 hours where there would have been a negative reserve margin (insufficient supply) and would have forced power curtailments;
- The reserve margin for ISO-NE would have been negative for 16 hours in January 2014, which would have forced power curtailments;
- PJM wholesale power prices would have been 40% greater without the coal plants, while ISO-NE wholesale prices would have been 50% greater and other regions would also have experienced large increases in wholesale prices;
- Consumers would have experienced an additional $35 billion in natural gas heating costs;
- Similarly large impacts would have occurred had there been extreme weather this past summer.

One cannot simply dismiss these warning signs about the affordability consequences of a less diverse electric grid as a one-time seasonal event. As Michael Kormos, Executive VP for Operations at the PJM Interconnection informed FERC:

Because less expensive coal generation is retiring and is being replaced by demand response or other high energy cost resources, excess generation will narrow and energy prices

[419] Southern Company reports first quarter earnings, available at http://www.southerncompany.com/news/iframe-pressroom.cshtml.
[420] EVA, "The Impact of Early Coal Retirements on Key Power Markets," May 2014 (attached hereto).

could become more volatile due to the increasing reliance on natural gas for electricity generation.[421]

The issue thus goes beyond just this past winter. MISO recently reported to FERC that its Central and North Regions are expected to fall below reserve margin requirements by 2.3 GW in 2016. MISO told FERC, "[z]onal survey results indicate uncertainty as to whether the system will have adequate resources to meet its desired reserve margin in 2016." According to MISO, "[a]s planning reserves erode, the probability of reliance on Emergency Operating Procedures and loss of load will increase."[422]

Commissioner Moeller has emphasized that "[w]e are now in an era of rising electricity prices. If you take enough supply out of the system, the price is going to increase."[423] EIA statistics bear this out. U.S. retail residential electricity prices for the first half of 2014 averaged 12.3 cents per kilowatthour, an increase of 3.2% from the same period last year. EIA reports that "[t]his is the highest year-over-year growth in residential prices for the first half of the year since 2009."[424] As illustrated in the map below from EIA, even nominal year-over-year natural gas price increases between 2012 and 2013 pushed up electricity prices nationwide. Notably, the regions with the highest increases are those with a less diverse generation mix—a mix dominated by natural gas-fired generation. The regions with the smaller electricity price increases rely primarily on coal-fired base load generation. However, EPA's MATS and Section 111(d) rules will force these regions to significantly cut their use of coal, thus making them vulnerable to volatile swings in natural gas prices that plague natural-gas-dependent regions.

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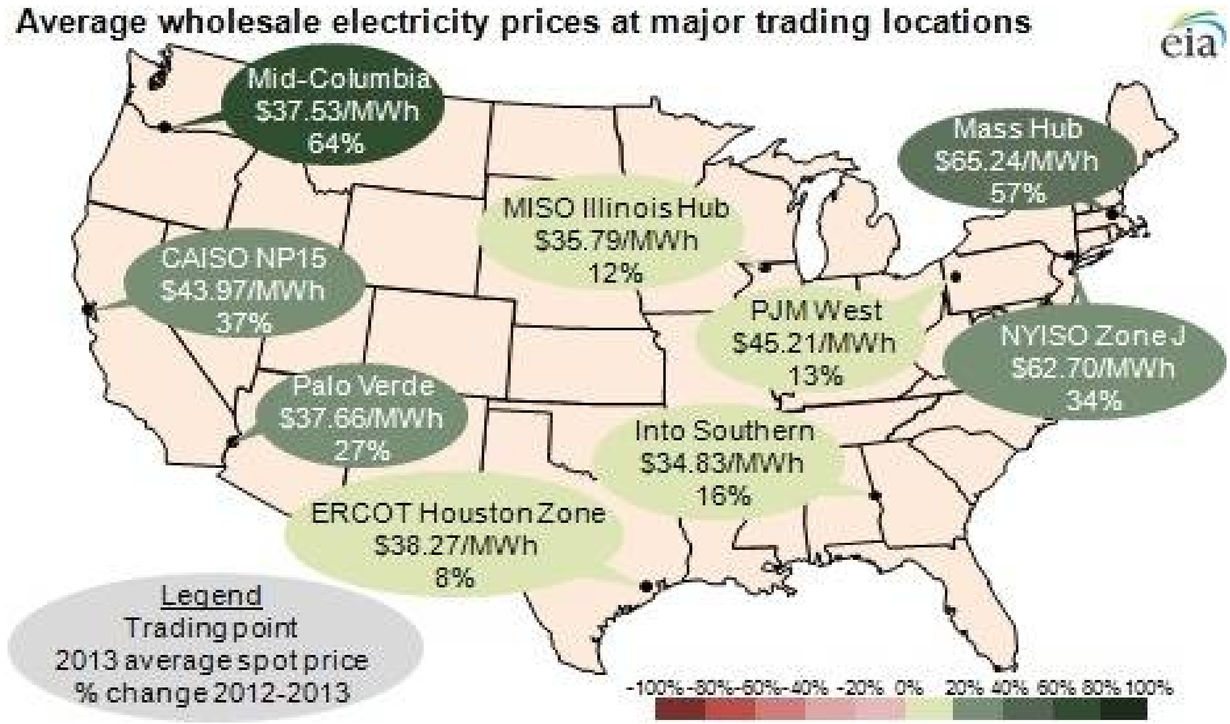
[421] Michael Kormos, Executive VP, PJM Interconnection LLC, Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference (April 1, 2014) Statement at 13, available athttp://www.ferc.gov/CalendarFiles/20140401084122-Kormos,%20PJM.pdf

[422] FERC Meeting 2014 MISO-OMS Survey Results, Clair Moeller, September 18, 2014 Attached hereto).

[423] As quoted in the L.A. Times, Apr. 25, 2014, http://www.latimes.com/nation/la-na-power-prices-20140426-story.html#page=1

[424] EIA, Today In Energy, Sept. 2, 2014.



Source: EIA

Before this recent winter, analysts were already forecasting a steady climb in natural gas prices going forward. JP Morgan projected that natural gas prices will climb to $8 mm/BTU by 2016—less than two years from now.[425] This is far higher than the assumptions EPA uses, citing EIA's last three AEOs, over a longer period of less than $6.00 at least through 2025.[426] Natural gas was priced at $6.00 as of Feb. 14, 2014 – already 13 percent higher than EPA's price assumption for natural gas six years from now.[427] Further, these recent forecasts of steadily rising natural gas prices appear too low in view of recent estimates of natural gas demand. ConocoPhillips projects domestic natural gas demand will exceed DOE/EIA's projection by **30 percent** in 2017.[428]

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425 Long-term gas prices poised to jump on global demand, economy: JP Morgan exec., Platts, Sept. 10, 2013
426 RIA at 2-25, Fig. 2-7.
427 The delivered price of natural gas to the power sector averaged $7.01/MMBTu in February 2014
428 *Increasing demand to shift to forefront of gas story: ConocoPhillips analyst*, Platts, Sept. 11, 2013 available athttp://www.platts.com/latest-news/natural-gas/chicago/increasing-demand-to-shift-to-forefront-of-gas-21540783

Obviously, this situation will worsen as even more coal units are forced to retire as a result of EPA's proposed rule. Commissioner Moeller warned that "[t]here are profound reliability implications of the Clean Power Plan that need to be thoroughly discussed and studied to assure the continued reliability of the nation's bulk power system."[429] In MISO, "there is the potential for widespread rotating blackouts if only parts of the system experience shortages."[430] Anthony Alexander, CEO, First Energy, recently commented that EPA rules will lead to less reliable service over time and that the EPA Section 111(d) proposal could have an impact similar to the MATS rule that has brought the electric grid to the edge.[431]

As the Virginia State Corporation Commission observed:

> The magnitude of what the Proposed Regulation requires Virginia (and the nation) to achieve by 2020 also raises obvious reliability concerns. Nationwide, EPA projects that the Proposed Regulation will, if not amended, cause 65,000 MW of fossil-fuel generation to retire by 2020. The effect on the national power systems of adding and removing significant infrastructure in a short period of time, as the Proposed Regulation would require in Virginia and throughout the nation, must be taken seriously. Indeed, Virginia does not yet have in place the infrastructure necessary to permit generation retirements soon required by other EPA rules issued years before the Proposed Regulation. *Additional near-term generator retirements caused by the Proposed Regulation will compound the existing, unresolved reliability concerns in the Commonwealth.*[432]

2. The sheer number of coal units that EPA is forcing to retire magnifies reliability concerns.

EPA's MATS RIA estimated that that rule would result in the retirement of about 5 GW of coal-fired generation. EPA lowballed its retirement number, as organizations like NMA told EPA in their MATS comments, and the actual retirements have proven to be 10-12 times as high

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429 *Id.*

430 Responses of FERC Commissioner Phillip D. Moeller to additional questions in connection with House Energy and Commerce Committee Hearing, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges, July 29, 2014, available at http://energycommerce.house.gov/hearing/ferc-perspectives-questions-concerning-epa%27s-proposed-clean-power-plan-and-other-grid.

431 Anthony Alexander, *Government Policies are Impacting Electric Service*, presentation to CEO Leadership Series, U.S. Chamber of Commerce (April 8, 2014) available athttps://www.firstenergycorp.com/content/fecorp/newsroom/featured_stories/AJA-Chamber-Speech.html

432 Comments of Virginia State Corporation Commission at 7 (footnotes omitted, emphasis in original).

as EPA's estimate. EPA is playing the same tricks again in the current rulemaking. It estimates that its proposed rule will result in 30-49 GW of retirements.[433] But while indicating that this projection is in addition to the MATS-caused retirements, EPA fails to note that its new, post-MATS baseline projects 66 GW of retirements by 2016, as compared with its previous estimate of 5 GW. In other words, EPA has quietly increased its estimate of the number of retirements that will result from compliance with MATS, which has the effect of reducing the number of retirements that the proposed rule's RIA predicts that the rule will cause.

The chart below compares EPA's MATS projections with its current projections.[434] As can be seen, between the MATS rule and the proposed rule, EPA will have caused the retirement of 119 GW of coal units, representing more than one-third of all preexisting coal capacity. Yet neither in the MATS rule nor the currently proposed rule will EPA have recognized the extent of the retirements its rules have caused.

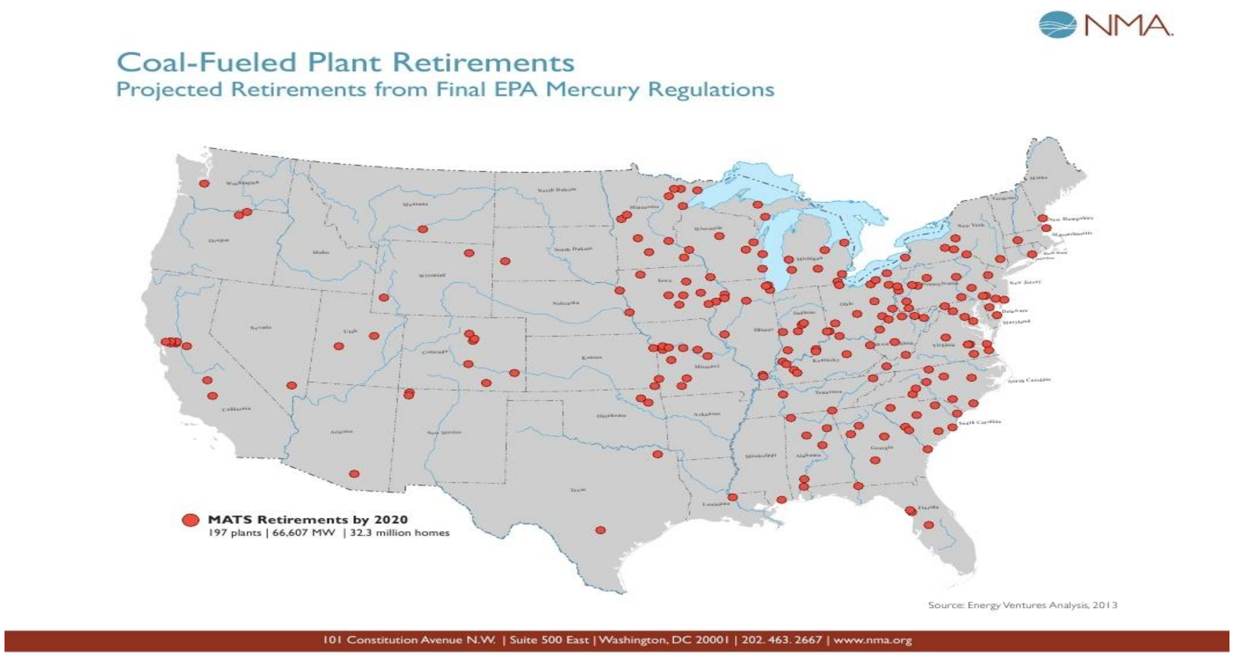
MATS 2010 Actual	MATS 2015 Base	MATS 2015 Reg	CPP 2016 Base	CPP 2020 Base	CPP 2020 Reg
317	310	305	244*	245	198

The magnitude of these retirements should be highly concerning. Most of these coal plant retirements will occur in regions where the reserve margins are already tight. Many of these regions will be forever exposed to rising and more volatile natural gas prices as the power sector demands more natural gas. As the map below shows, the largest reduction in coal base load capacity will occur in states with the highest concentration of manufacturing, as measured

433 RIA at 3-32.

434 All information is taken from MATS RIA, Table 3-8 at 3-19 and CPP RIA, Table 3-12 at 3-34, except the number marked with an asterisk is taken from the spreadsheet Proposed Clean Power Plan_Base Case_ssr.xlsx, EPA Analysis of the Proposed Clean Power Plan, IPM Run Files, http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html.

by manufacturing share of state GDP.[435] It is far from coincidental that states with the highest concentration of manufacturing are states where coal-fired electricity is the predominant source of base load power. EPA's policies will impair the global competitiveness of manufacturers in these states by (1) increasing their electricity costs; and (2) leaving them vulnerable to higher and more volatile prices for the natural gas they need as feedstock for their products and production processes:



Source: EVA, 2013

Unlike the retirements between 2010 and 2012, which consisted primarily of smaller and oldest plants, the plants scheduled for retirement over the next 10 years are larger and more efficient with an average size 50 percent larger than recent retirements and lower average heat rates of 10,398 Btu/kWh:[436]

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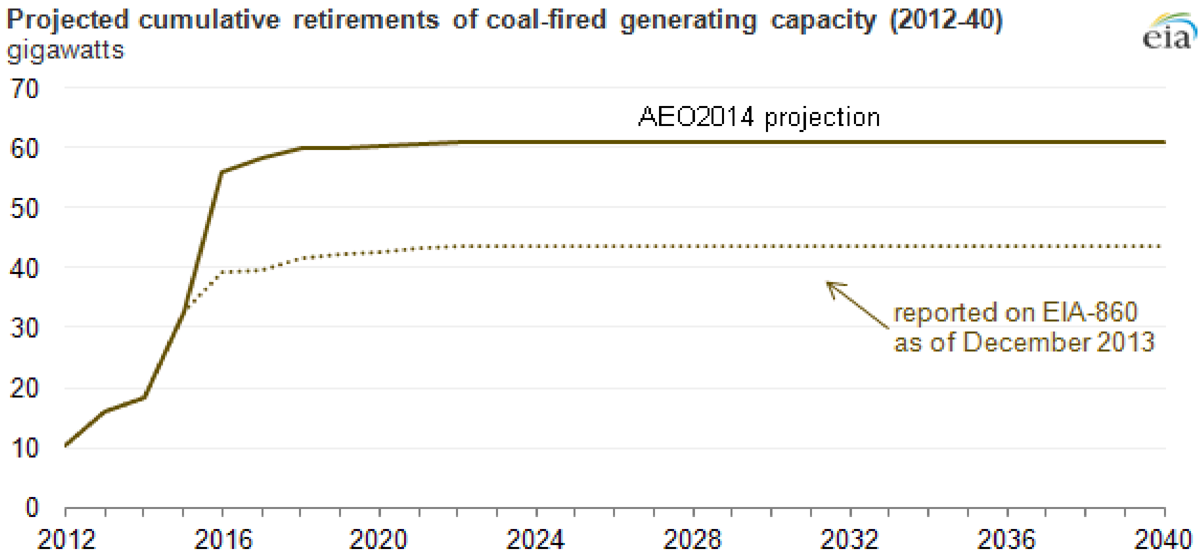
[435] National Association of Manufacturers, US Manufacturing Statistics, available at http://www.nam.org/~/media/36FEC7FD518342259F02B79F0AB1F809/MFG_GSP_FactSheet_Nov2013.pdf.
[436] *Id*.



Source: EIA AEO 2014

In every power sector air quality and GHG rulemaking that EPA has conducted since the Obama Administration has taken office, NMA has called on EPA to prepare a cumulative assessment of its regulations so that the total effects of these regulations taken together can be understood. NMA reiterates that demand below. The sleight of hand that EPA has engaged in regarding the collective effect of MATS and the proposed rule together demonstrate the importance of a credible cumulative assessment. More importantly, the effect of these retirements will leave the grid short of the resources it needs where it needs them and therefore undermine reliability.

3. Despite the major impacts the rule will have on grid reliability, EPA failed to conduct a proper grid reliability assessment.

Although EPA professes that it believes maintaining the reliability of the grid is paramount,[437] in fact it did not conduct an analysis of the impact its proposal will have on grid reliability. NERC has not conducted such a study nor, to NMA's knowledge, has any other grid reliability regulator. The Western Electricity Coordinating Council has informed state regulators

437 79 Fed. Reg. at 34,833.

that it has not performed that study and that it does not have time to do so before the comment deadline.[438] The SPP has warned that a "[m]ore comprehensive reliability analysis is needed before final rules are adopted."[439] ERCOT states that "[i]t is unknown based on the information currently available whether compliance with the proposed rule can be achieved within applicable reliability criteria and with the current market design."[440]

NERC's recent assessment of EPA's proposal strongly recommended that local reliability assessments be performed, including specific generator retirement studies, specific generator interconnection studies, specific generator operating parameters, studies of power flow (thermal, voltage), studies of stability and voltage security, and studies of offsite power for nuclear facilities.[441] It also recommended area and regional reliability assessments, including studies of resource adequacy, power flow (regional), stability and voltage security (regional), gas interdependencies, pipeline constraints, operating reserves and ramping, and system restoration/blackstart.[442] NERC's overall conclusion as stated in its press release: "we believe there must be further detailed engineering analysis to demonstrate whether the assumptions and targets are feasible in the timeframe proposed."[443] None of these studies have been conducted.

EPA conducted what it inaccurately called a grid reliability analysis by running the IPM model.[444] As the Kansas Corporation Commission and others have pointed out, IPM grid simulations, however, are not true reliability analyses.[445] They provide a much simpler "resource

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438 Kavulla Testimony at 3-4.
439 Southwest Power Pool presentation to Arkansas Department of Environmental Quality/Arkansas Public Service Commission Stakeholder Meeting, October 1, 2014 (SPP Arkansas Presentation) (attached hereto).
440 ERCOT Report, at 2.
441 NERC Report at 26.
442 *Id.*
443 NERC, Media Release, Reliability Review of Proposed Clean Power Plan Identifies Areas for Further Study, Makes Recommendations for Stakeholders, November 5, 2014, available at http://www.nerc.com/Pages/default.aspx.
444 *See* Resource Adequacy and Reliability Analysis TSD.
445 Comments of Kansas Corporation Commission at 19-20.

adequacy" analysis,[446] examining only whether the total amount of electric capacity that will be forced to retire within broad regions will cause capacity levels to fall below regional reserve requirements.[447] IPM "*assumes* that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region."[448]

The IPM analysis, however, is flawed in two fundamental respects. First, it ignores real-world barriers to resource development that undermine its efficacy even as a resource adequacy analysis. This is discussed in more detail in the next section below.

The other way in which the IPM analysis is flawed is that it ignores the fact that, in the real world, system dispatch is subject to localized constraints that impede the flow of electricity across broad regions, including intraregional transmission constraints, particularly around metropolitan areas. These constraints create transmission-congested "load pockets" with limited access to remote resources. As a result, certain local, primarily coal units cannot be retired because they are needed to maintain voltage levels and to assure "black start" capability (to bring generation on line quickly in the event of a system emergency). As then FERC Chairman Wellinghof informed Congress in hearings on whether EPA was coordinating its UMATS grid reliability analyses with FERC, regional resource adequacy studies of the type EPA performed through the IPM, which don't take into account local reliability bottlenecks, are "irrelevant" in assessing the impact of EPA regulations on grid reliability.[449] And FERC Commissioner Spitzer stated:

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[446] As EPA states, "IPM is specifically designed to ensure generation resource adequacy." Resource Adequacy and Reliability Analysis TSD at 2.

[447] IPM TSD Appendices A1-A3.9.

[448] Resource Adequacy and Reliability Analysis TSD.at 2 (emphasis added).

[449] The American Energy Initiative: Impacts of the Environmental Protection Agency's New and Proposed Power Sector Regulations on Electric Reliability, Before the Subcomm. on Energy and Power of the H. Comm. on Energy and Commerce, 112th Congress (September 14, 2011) (response of FERC Chairman Wellinghoff to question by Rep. Rush) ("Electric Reliability Hearing"). The hearing transcript is available on Lexis.

> [A]s my colleagues have all pointed out, location matters in electricity, and substantial excess capacity in Nevada may not help with the folks in Arizona, where I come from if three coal plants that have issues disappear from the grid.[450]

FERC Commissioner Moeller made the same point in his testimony, referring to older, less-controlled coal plants that are most likely to be forced to retire because of EPA's regulations and that tend to be located within or near metropolitan areas:

> But here is my concern from a reliability perspective. Smaller plants are typically dirtier and older, but there are advantages in the system to smaller plants. They ramp up and down faster, they might be in locations where the voltage support is key. And I can go through a variety of other examples … where they are located can make a lot of difference. *And that's why I think we need to dig down deeper into the impacts here, because … there will be a disproportionate number of smaller, older, dirtier plants affected. But their role in the overall electric grid needs to be better analyzed.*[451]

EPA's use of a generation resource adequacy model to determine whether the transmission grid will operate reliably is arbitrary and capricious. *Sierra Club v. Costle,* 657 F.2d at 333 (A model may not be used for purposes that "exceed the bounds of its usefulness."). And this is no small matter because "local" grid reliability impacts can have cascading effects over a broad region. For instance, in September 2011, a mistake by a single utility maintenance worker in Yuma, Arizona left millions throughout the Southwest and Mexico without power, many for days.[452]

Moreover, even as a regional resource adequacy analysis, IPM fails because the model builds as many new natural gas units as are necessary to meet reserve requirements.[453] In reality, however, the construction of new natural gas units may be constrained by numerous factors, including the need to obtain sites and regulatory approvals and to bid into capacity markets where applicable.

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[450] *Id.* (response of Commissioner Spitzer to question by Rep. Rush).
[451] *Id.* (response to question by Rep. Rush (emphasis added)).
[452] *See* http://www.reuters.com/article/2011/09/09/us-outage-california-idUSTRE7880FW20110909. at 333.
[453] Resource Adequacy and Reliability Analysis TSD at 3.

In sum, even if a court accorded EPA deference as to its grid reliability predictions based on an assertion that the Agency has expertise in this area, that "expertise cannot be used as a cloak" for EPA's "fiat judgments" here.[454] Courts "'do not defer to [an] agency's conclusory or unsupported suppositions.'"[455] In the absence of any reasoned explanation to justify EPA's confidence that the real-world grid can accommodate the near-term impacts of its proposed rule, the proposal cannot be justified.

4. The rule will impair reliable grid operations.

A host of bodies with responsibility for the grid have warned that EPA is ignoring the effect the rule will have on the reliability of the grid. Perhaps the most significant concern is that EPA is understating the amount of coal power that will be retired and the real-world barriers to constructing both replacement generation and the pipeline and transmission infrastructure needed to support that replacement generation.

The SPP, for instance, observed that "EPA projects about 9,000 MW of retirements in the SPP region by 2020" and that "this is almost 6,000 MW more than SPP is currently expecting!" (Exclamation point in original). It reported that, as a result, "[s]ignificant new generating capacity not currently planned will be needed to replace EPA's projected retirements," and that "[n]ew transmission infrastructure will be needed, both to connect new generation to grid and to deliver energy reliably." It warned that "[u]p to 8.5 years [is] required to study, plan, and construct transmission in SPP," at a cost of "[u]p to $2.3 million per mile." Obviously, the rule will not permit sufficient time to construct this new transmission, as the rule goes into effect in 2020. Given that timeline, the SPP found that the rules, as proposed, "[w]ill result in significant loss of load and violations of NERC reliability standards," with "[s]ome overloads so severe that

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454 *Tennessee Gas Pipeline Co. v. FERC,* 926 F.2d 1206, 1211 (D.C. Cir. 1991).
455 *NetCoalition v. SEC*, 615 F.3d 525, 539 (D.C. Cir. 2010), *quoting McDonnell Douglas Corp. v. U.S. Dep't of the Air Force*, 375 F.3d 1182, 1187 (D.C. Cir. 2004).

cascading outages would occur," and would leave the region far below needed reserve margins and below the amount of power needed to meet load even without considering reserve margins. "Out of 14 load serving members assessed, 9 would be deficient by 2020 and 10 by 2024."[456]

MISO has made a similar warning. In its comments to EPA, MISO concluded that "[t]he interim performance requirements are likely to have a negative impact on electric system reliability."[457] MISO stated that:

> *The MISO region already faces identified reliability challenges associated with EPA's Mercury and Air Toxics Standards (MATS).* The MISO region relies on coal-fired generation as the predominant electricity resource. MISO has been conducting quarterly surveys with our generation owners for three-and-a-half years to assess potential impacts of the MATS rule. The survey results show that between 10 and 12 gigawatts of coal-fired generation capacity will retire by 2016 to meet the MATS requirements. *As a result, resources available to the MISO region will be at, or potentially below, the planning reserve margin starting in the summer of 2016. MISO expects that resource availability will remain close to the planning reserve margin for the foreseeable future. This erosion of the reserve margin increases the likelihood that MISO will need to manage high electricity demand situations by use of emergency operation procedures. The probability of a loss of load event becomes greater than the MISO region has ever experienced.*[458]

MISO reported that "[t]he MISO region will face serious resource adequacy issues, which translate into reliability issues."[459]

ERCOT states that "the timing and scale of the expected changes needed to reach the CO_2 emission goals could have a harmful impact on reliability. Specifically, implementation of he Clean Power Plan in the ERCOT region, particularly to meet the Plan's interim goal, is likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges."[460]

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456 *See* SPP Presentation.
457 MISO November 25, 2014 comments to EPA.
458 *Id.* (emphasis added).
459 *Id.*
460 ERCOT Report at 1.

NERC's recent assessment of the proposal came to the same conclusion. It reported that "[l]ong lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook…A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews."[461]As the Edison Electric Institute has reported, "[l]engthy, complicated, and costly siting and permitting processes continue to be major barriers to installing new transmission lines and upgrading existing lines."[462] Texas reports that it takes 4-7 years to design, site and build transmission, a process that takes longer in other states.[463] Given these long lead times, NERC has expressed "concern[] that reliability-related enhancements may not be able to be completed for a 2020 implementation."[464]

Long lead times for infrastructure development is not the only issue motivating reliability concerns. Even more basic is the concern that EPA is forcing an overdependence on natural gas and variable resources. As to natural gas, NERC and others have highlighted last winter's events, where freezing conditions prevented pipelines and gas generators from operating. According to NERC, "[t]his increased reliance, compounded by generation outages during the extreme conditions, increased the risks to the reliable operation of the [grid]."[465] NERC reported that while most generators operated within normal ranges, "[t]he exception is natural gas units, which in two Regions experienced a higher-than-expected EFOR [Equivalent Forced Outage Rate]. This observation validates the concerns that NERC raised in the *2013 Long-Term Reliability Assessment* on increased dependence on natural gas for electric power."[466] As NERC

461 NERC Report at 20.
462 EEI, Transmission Investment, June 2013.
463 Anderson Testimony at 14.
464 NERC Report at 21.
465 NERC, "Polar Vortex Review," September 2014 at 17, available on NERC website.
466 *Id.* at 18 (footnote omitted).

stated more recently, with "the shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks… "[o]verdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events."[467]

Similarly, EPA fails to analyze the effect increased reliance on wind and solar will have on the reliability of the grid. As NERC states:

> wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.
>
> Based on industry studies and prior NERC assessments, as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP.[468]

5. EPA failed to consider ongoing and future retirements of non-coal capacity.

The unprecedented closure of coal base load capacity is not the only development affecting the future reliability and affordability of the electric grid. Since 2010, the 23,714 MW of capacity retirements of natural gas (12,167 MW), nuclear (4,200) and oil (6,793) electricity plants have exceeded the 19,472 MW of coal capacity during this period.[469]

Presently, approximately 25 percent of the coal, natural gas and nuclear base load capacity is 40 years or older. The capacity of natural gas plants and coal plants are roughly equal

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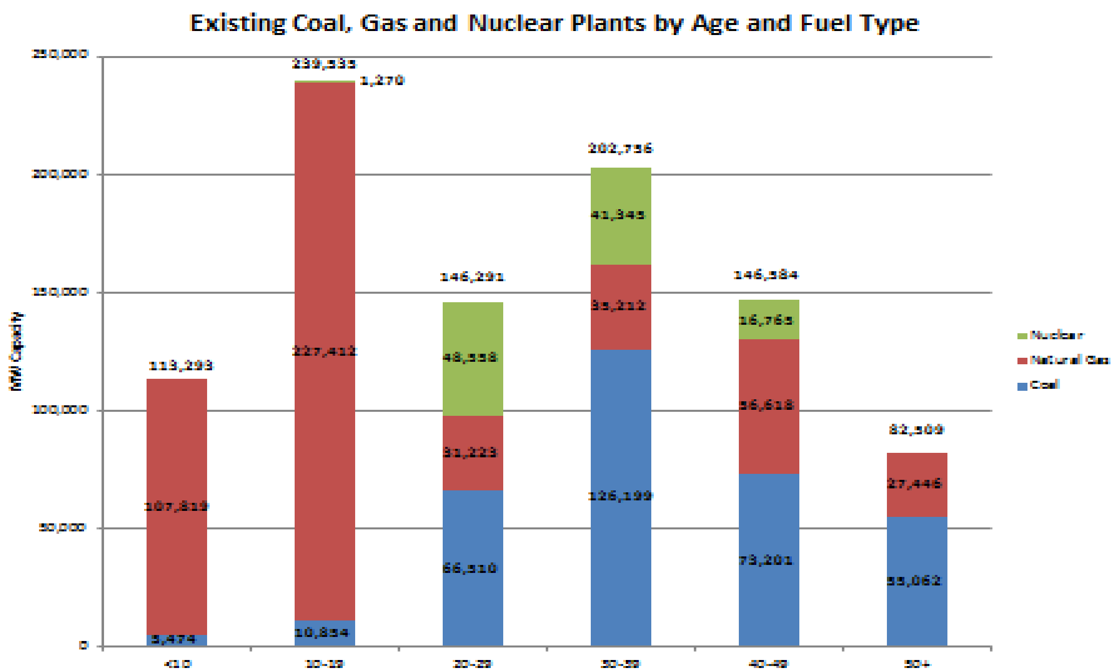
[467] NERC Report at 24.

[468] *Id.* at 25.

[469] The 5,500 MW of nuclear capacity currently under construction will barely offset the nuclear capacity that has closed or is scheduled for closure between 2012 and 2019. In short, nuclear capacity will struggle to maintain its current 18-20 percent share of electricity generation. This will place even more upward pressure on natural gas prices since the older nuclear plants have lower variable operating costs which assures they are dispatched when available

in the 40-plus years demographic. Within ten years, the 40-plus years demographic will increase to about 50 percent of the *entire* base load fleet. It is clear that, going forward, new coal plant additions will be necessary to maintain system diversity, reliability and affordability, yet EPA's proposed new source rule will prevent these necessary additions from being constructed. As the chart below illustrates, absent new coal additions, the base load electricity fleet will become increasingly reliant on natural gas, with less competition to deliver power and restrain large price increases:



EPA did not factor any of these trends and what they portend into its analysis.

6. EPA failed to consider the potential elimination of FERC's ability to mandate demand-response measures.

EPA's purported grid reliability analysis is made obsolete by the D.C. Circuit's decision in *Electric Power Supply Ass'n v. FERC*, 753 F. 3d 216 (D.C. Cir. 2014), in which the Court struck down FERC's authority to implement mandatory demand-response measures. Demand response programs have become a major part of the way grid operators ensure that reserve margins are met. As PJM informed the court:

> demand response has become a major contributor to the PJM system's need for capacity. PJM and other grid operators have long had rules that identify the total installed capacity needed to meet their region's expected peak loads (including a reserve for contingencies) and that require participating utilities or others serving loads to show that they have built or contracted for sufficient capacity to serve their particular customers. Over the last ten years, PJM and other grid operators, with FERC approval, have allowed voluntary demand response commitments to compete to satisfy these capacity needs. The forward commitment by demand response providers to reduce (upon request) consumption of megawatts at the system peak has the same reliability value as a forward commitment to build a new generator to produce (upon request) those megawatts at the system peak. In these long-term reliability markets, a forward commitment to generate more and a forward commitment to consume less are functionally the same capacity product.[470]

PJM informed the court that "[d]emand [r]esponse [h]as [b]ecome a [v]ery [s]ignificant [s]ource … [o]n [w]hich the [g]rid [d]epends for [r]eliability."[471] According to PJM:

> By the start of the 2014 peak summer season, demand response providers had committed *over 8,000 megawatts* of load reduction capability that PJM can call upon to help balance supply and demand when the system faces emergency conditions or other system stresses. For comparison, a typical major new power plant might provide 300 to 700 megawatts of generation capability; 8,000 megawatts is more than the highest usage ever recorded for the *entire* electric load of Washington D.C. and its Maryland suburbs. PJM's June 2014 demand response report, James McAnany, *2014 Demand Response Operations Markets Activity Report: June 2014,* PJM, 5, (June 18, 2014) shows that demand response providers had identified to PJM 9,362 megawatts of emergency and load management demand response to cover their capacity commitments for this year. To ensure they are covered, providers identify more load reduction megawatts than they are committed to provide; for this year, they identified about fifteen percent more than their actual commitment level of 8,104 megawatts.[472]

Obviously, the court's decision will have a very significant effect on the ability of grid regulators to maintain adequate reserves. Given the significant impacts that EPA's proposal will

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470 Petition for Rehearing En Banc of PJM Interconnection, L.L.C. in Docket No. 11-1486 (D.C. Cir.) at 6-7.
471 *Id.* at 7.
472 *Id.* at 7-8 (emphasis in original) (footnotes omitted).

have on an already stressed grid, EPA must now reanalyze its proposal in light of the additional stresses the court's decision will create.

D. EPA's Natural Gas Analysis Is Deficient.

As is clear, EPA's assumptions as to natural gas supply, pricing and the timely availability of supporting infrastructure are key underpinnings of the rule. These assumptions, however, are inaccurate in a number of ways in addition to those identified above.

1. EPA is wrong that its proposal builds on a long-term market trend to replace coal generation with natural gas generation.

EPA incorrectly claims that its proposal to redispatch coal generation to NGCC generation builds on a trend already underway in the power sector of relying more on natural gas and less on coal.[473] EPA fails to recognize that market-caused shifts between coal and gas generation are temporary. For instance, when natural gas delivered prices to electric utilities fell to their recent lows in 2012 (April 2012 @ $3.12 MM/Btu), coal and natural gas generated roughly the same amount of electricity (Coal-96.3 TWh vs. Gas 94.8TWh) nationwide. However, less than one year later in February 2013, with natural gas prices at $4.30/MMBtu, coal generation increased by almost 30 percent (123.8TWh), while natural gas generation decreased by almost 16% (79.9TWh).

Thus, natural gas prices are a temporary cyclical factor, while coal-fired plants can run at higher or lower capacity factors depending upon overall demand and the relative price of coal and natural gas. On the other hand, EPA policies—such as MATS and the proposed rule here—force the retirement of coal base load power plants and are therefore a permanent structural barrier to assuring the electric grid remains diverse enough to minimize both reliability crises and higher and more volatile prices that reverberate throughout the economy. As a result, it is not

[473] 79 Fed. Reg. at 34,863.

correct for EPA to claim that its proposal merely builds on a preexisting trend; EPA itself is the cause of a massive shift of coal generation to gas and of the consequences that will ensue. As DOE warned in 2009, "policies that encourage the use of natural gas to substitute for coal in power generation could very well lead to spectacular price increases for households and industry."[474] That assessment turns out to be prophetic.

EPA's view that the unprecedented size of coal EGU retirements are a product of natural gas prices and not the Agency's policies is also directly refuted by a study performed by the Duke University Nicholas School of Environment. According to the Duke study, "most of the planned [coal plant] shutdowns are more a response to the stricter regulations than to low natural gas prices."[475] Without the MATS rule, only 9 percent of the current coal capacity was economically threatened when natural gas prices dropped to their lowest in 2012.[476] Furthermore, the authors found that:

> Coal plants would again become the dominant least-cost generation option should the ratio of average natural gas to coal prices (NG2CP) rise to 1.8. In fact, the NG2CP is predicted to rise back up toward 2 by 2020. In the absence of EPA rules, this would result in >85% of the current coal fleet capacity once again having a lower COE than the *cheapest* natural gas plant.[477]

In February 2012, the month before the study was published, the price of coal for electricity generation was $2.41/MMBtu and the price for natural gas was $3.72/MMBtu, for a NG2CP ratio of 1.4. At a ratio of 1.8, the price of natural gas would be at $4.28/MMBtu.[478] The 1.8 NG2CP ratio has been exceeded for 19 of the 21 months between November 2012 and July

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[474] DOE/NETL, Natural Gas and Electricity Costs and Impacts on Industry, DOE/NETL-2008/1320 p. 11 (April 28, 2008).

[475] Pratson, Lincoln F., Drew Haerer, and Dalia Patino-Echeverria, "Fuel Prices, Emissions Standards, and Generation Costs for Coal vs Natural Gas Power Plants," *Environmental Science & Technology*, 47 (9) pp. 4926-4933 (March 15, 2013).

[476] *Id*.

[477] *Id*.

[478] For 2013, the average cost of coal delivered to electric utilities was $2.38/MMBtu. EIA, Electric Power Monthly, Table 4.2 (April 2014), available at http://www.eia.gov/electricity/monthly/index.cfm.

2014.[479] In February 2014, the cost of natural gas delivered to electric utilities reached $7.01/MMBtu as compared to coal prices of $2.33/MMBtu, for a ratio of 3.03. In July 2014, the ratio fell back to 2.01.[480]

The Duke study also found that, with EPA regulations, natural gas prices to utilities can increase to more than four times the coal price (NG2CP of 4.3) and remain competitive with coal plants.[481] In other words, EPA's finalized MATS regulations have made natural gas plant dispatch much less sensitive to the rise in natural gas prices.

2. EPA failed to account for the demonstrated unreliability of EIA projections.

EPA relies on EIA natural gas forecasts in determining, under building block two, that redipatching large amounts of coal-fueled electricity to NGCC units is economically viable.[482] It has become increasingly apparent, however, that EIA forecasts for natural gas differ substantially from outcomes. AS EPRI reports, "history has demonstrated the price of natural to be highly volatile, and multi-year forecasts have consistently been inaccurate."[483] A striking example of this difference is in 2002, when EIA projected the cost of natural gas to electric utilities in 2006 would be $3.85 per thousand cubic feet (Mcf) (2006 dollars). The actual cost was $7.56. Further, in 2003, EIA overestimated domestic production in 2006 by almost 2 trillion cubic feet—more than the annual natural gas production of natural-gas rich Oklahoma.

These problems are systemic. An error-decomposition analysis of one-, two-, three-, and four-year-ahead forecasts by EIA from 1998 to 2006 revealed that:

- On average, a one-year ahead-average percentage forecast error for wellhead natural gas prices of 16 percent, with the errors steadily increasing to more than

[479] *Id.*
[480] *Id.*
[481] Pratson et al., *supra*
[482] 79 Fed. Reg. at 34,857.
[483] EPRI Comments at 4.

45 percent with the four-year-ahead forecast. More than 54 percent of the errors for the one-year-ahead forecasts can be attributed to systematic bias;[484]

- Natural gas consumption in electric generation is consistently below actual observations. The absolute error for the one-year-ahead forecast was more than 900 billion cubic feet—more than 15 percent of consumption in the electric sector for that year;[485]

- Dry natural-gas production is consistently over-predicted. The absolute errors are quite sizeable. The two- through four-year-ahead forecast errors exceed one trillion cubic feet.[486]

The analysis indicates that the forecast errors are not reflective of random chance. Rather the forecasts contain evidence of systematic bias, either arising from a fixed, linear bias or from a systematic error coming from the NEMS model.[487] These biases emerge over a much shorter period (4-year horizons) than the 10-year plus scenarios that EPA is conducting for this rulemaking.

The prospect of even greater errors on the critical factors of natural gas supply, power sector consumption and natural gas prices is highly probable, if not a certainty. For instance, in the first two months of 2014, the delivered price of natural gas breached $7.46/MMBtu and during February reached $7.78/MMBtu—*well above* EIA's previously forecasted price for that same time period. AEO 2013 did not project delivered natural gas prices to the power sector to reach $7.00 until 2035—a projection that was proven inaccurate by a mere 21 years. AEO 2014 appears equally inaccurate and obsolete since the reference case pegs delivered natural gas prices

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[484] Considine and Clemente, "Betting on Bad Numbers," p. 55, *Public Utilities Fortnightly* (July 2007), available at http://www.fortnightly.com/fortnightly/2007/07/gas-market-forecasts-betting-bad-numbers.

[485] *Id*. at 56

[486] *Id*. EIA's AEO Retrospective Review confirms that its reference case has a tendency to *significantly* underestimate of the natural gas wellhead price, and from AEO 2000 to the present electricity prices were *almost always underestimated.*

[487] *Id*. at 57

reaching \$7.00 in 2035—about the same time as AEO 2013.[488] We reached the \$7 price point two decades earlier than EIA forecasts.

Both the AEO 2013 and AEO 2014 reference cases contain dubious and unsustainable projections. These include:

- The projected demand for natural gas is significantly underestimated. EIP predicts that natural gas demand will increase substantially to replace the lost generation from current and projected coal plant retirements and higher consumption from the industrial sector as additional manufacturing capacity in gas-intensive industries come to the U.S. in the face of higher natural gas costs in Europe and Asia. AEO 2013 and 2014 forecast a natural gas demand increase of 7 percent between 2013 and 2022. NMA's analysis indicates that the combination of increased power and industrial sector consumption will increase demand in that period by 15 percent – a 1.83 Tcf difference from the EIA estimate.[489] NMA's analysis and EIA's forecast begin to diverge by 1 Tcf by 2014 with that gap beginning to widen in 2020. All of this coincides with the increased coal plant retirements in 2014 through 2020. At a minimum, EPA must look at the retirements of coal-fired EGUs that are known and forecasted and calculate the natural gas requirement to replace that generation. After all, EPA states in its proposal that it anticipates that most of the lost coal generation will be filled by new natural gas-fired generators and increasing the capacity factors at existing natural gas-fired EGUs. It must also look more closely at more recent analysis on growing industrial sector consumption;

- The forecasted natural gas prices are too low to support the supply growth rate AEO 2014 forecasts, and are well below levels necessary to sustain the supply growth other analysts peg at twice the level forecasted by EIA. With shale gas comprising a greater share of overall supply in all forecasts,[490] neither AEO 2013 nor 2014 account for the steep decline rates for shale wells and the impact on ultimate recovery. The steep decline rates require a constant drilling treadmill of more expensive wells at a faster pace just to maintain current production levels. The recent shift of drill rig deployment from dry gas to oil and liquid rich reserves

[488] EIA, AEO 2014 Table A3, Energy prices by sector and source (April 7-30 Release Dates), available at http://www.eia.gov/forecasts/aeo/.

[489] EPA can readily calculate the potential increase in natural gas demand for the power sector. By tabulating the power plants that have announced plans to close and those likely to close (available in various analysis available over the past three years) and then calculating the amount of natural gas needed to replace the "retired" coal generation from a base year such as 2011. Thomson Reuters North America Natural Resource Team calculated a 1.9 bcfd natural gas requirement to replace coal generation retired by 2018. See Julia Edwards, Reuters "Analysis: Supply test looms for darling natural gas" (Jan. 30, 2014) available at http://articles.chicagotribune.com/2014-01-30/business/sns-rt-us-usa-naturalgas-demand-analysis-20140130_1_natural-gas-prices-more-gas

[490] Shale gas grows as a percentage of all supply as a result of a combination of increased shale production, declining production of conventional gas and declining natural gas imports. About one-third of the shale gas supply offsets the decline from other sources.

is one of several signals that prices are inadequate to sustain the replacement rate.[491] Some analysts have concluded that gas prices in the range of $8.00 to $9.00/Mcf are required to break even on a full-cycle basis.[492] Notably, the growth rate of dry gas production has slowed since 2011 with lower pricing. In 2013, the growth rate was less than 1 percent.

3. EPA misunderstands and misapplies the domestic natural gas resource base.

EPA's assessment of energy requirements and available natural gas supply reflects a fundamental misunderstanding about the distinction between resources and reserves. EPA uses EIA's AEO 2012 estimates that the U.S. possesses 2,214 Tcf of technically recoverable resources (TRR) of natural gas.[493] It then proceeds to assert that at current rates of consumption, the resources are "enough to supply over 90 years of use."[494] In reality, only a small subset of the TRR can be considered "reserves" (about 24 years currently of potential supply) reasonably available for consumption. This distinction is especially important in the context of the proposed rule because EPA policies will drive increased reliance on natural gas for power generation and preclude the deployment of the nation's enormous coal reserves—the most cost-effective fuel for base load power generation. A balanced policy would conserve both resources, not simply attempt to elevate one at the expense of the other.

The technically recoverable resources are divided into three categories: (1) speculative; (2) possible; and (3) probable. Only the probable TRR have been tested by drilling and known to be, in fact, technically recoverable. Approximately 30 percent of the TRR is classified as

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491 Major companies taking significant write-downs of the value of shale gas assets also provides a signal that lower well quality (as measured by initial productivity) will not sustain EIA's optimistic production growth without much higher prices. Shell took a $2 billion write down of North American assets last year and announced plans to sell its stake in Eagle Ford Shale because of "disappointing" performance that did not meet the company's profitability targets.

492 Berman, Pittinger, U.S. Shale Gas: Less Abundance, Higher Cost, *The Oil Drum* (Aug. 5, 2011), available at http://www.theoildrum.com/node/8212.

493 RIA at 2-23.

494 *Id*.

probable,[495] and only about half of the probable TRR is likely to become reserves. In other words, only 15 percent of the entire TRR are likely to be considered as consumption reserves.

Using the AEO 2012 TRR estimate of 2,214 Tcf as cited by EPA, the probable TRR is 664 Tcf—or about 25 years of supply at the consumption rates over the past two years (26.60 Tcf). Converting the probable TRR to reserves equals about 332 Tcf that can be added to the already proved reserve base of 305 Tcf. The combined total of 635 Tcf leaves 24 years of supply at current consumption rates.[496]

Of course, economic viability is a key factor whether resources are eventually converted to reserves and developed. Higher prices would convert more probable resources to reserves. However, these higher energy prices carry consequences for the other sectors consuming natural gas and the economy as a whole. EPA's assessment lacks any analysis of the economic effects of the likely prospects of either higher natural gas prices or a gap in incremental natural gas supply. Less than a quarter century of natural gas reserves is a thin supply margin to risk on a policy that will have profound effects on the economy but not make any material difference in direct global temperature changes.

4. EPA failed to assess the economic effects on other economic sectors from higher natural gas prices or potential gaps in the incremental natural gas supply.

Numerous sectors of the economy rely on natural gas. Each of these sectors has increased natural gas consumption and exceeded its pre-recession level, with the power and industrial sectors as the largest consumers with the largest consumption increases between 2009-2012 (Power-32%; Industrial-17%). In 2013, consumption for power generation fell somewhat, but still exceeded 2009 by 19%. However, industrial consumption of natural gas continued to

[495] The Potential Gas Committee 2013 report classified 708 Tcf of its 2,226 Tcf TRR estimate as probable.
[496] The current consumption rates *do not* reflect the higher power sector consumption due to over 60,000 MW of coal plant retirements.

rise in 2013, exceeding 2009 consumption by 20%. Natural gas use for the transportation fleet continues to increase and many policies are underway to support accelerated growth in the transportation sector. Natural gas exports will begin to coincide with the accelerated retirement of coal generators. Four liquefied natural gas export projects approved so far by DOE have the capacity to export 7.1 bcfd of natural gas by 2018, amounting to more than 10 percent of the current daily supply of 70 bcfd. Indeed, the Sabine Pass liquefaction terminal will begin operations at the end of 2015 and has locked customers into 20-year contracts.[497] U.S. exports of natural gas to Mexico are expected to rise by 3.5 bcfd by the end of this year according to DOE—nearly double the current rate.[498]

EPA's analysis does not even touch upon, let alone analyze, any of these market developments and how the proposed rule will affect the economic sectors and residential customers that depend upon natural gas. Recent history provides more than ample experience on the scope and depth of the consequences of overrelying on natural gas. Between 1997 and 2009, the natural gas market experienced five significant price spikes which contributed to the loss of nearly 4 million jobs in manufacturing. These spikes also turned a $19 billion U.S. chemical trade surplus into a deficit from 2001-2007. This occurred even when natural gas demand fell—but prices increased by 160 percent. All of this coincided with an increase in natural gas power plant builds and a 27 percent increase in natural gas consumption in the power sector—more than *three times* the overall growth in natural gas demand by all sectors. There is little question of the direct correlation between manufacturing job losses and higher and more volatile natural gas prices during this period:

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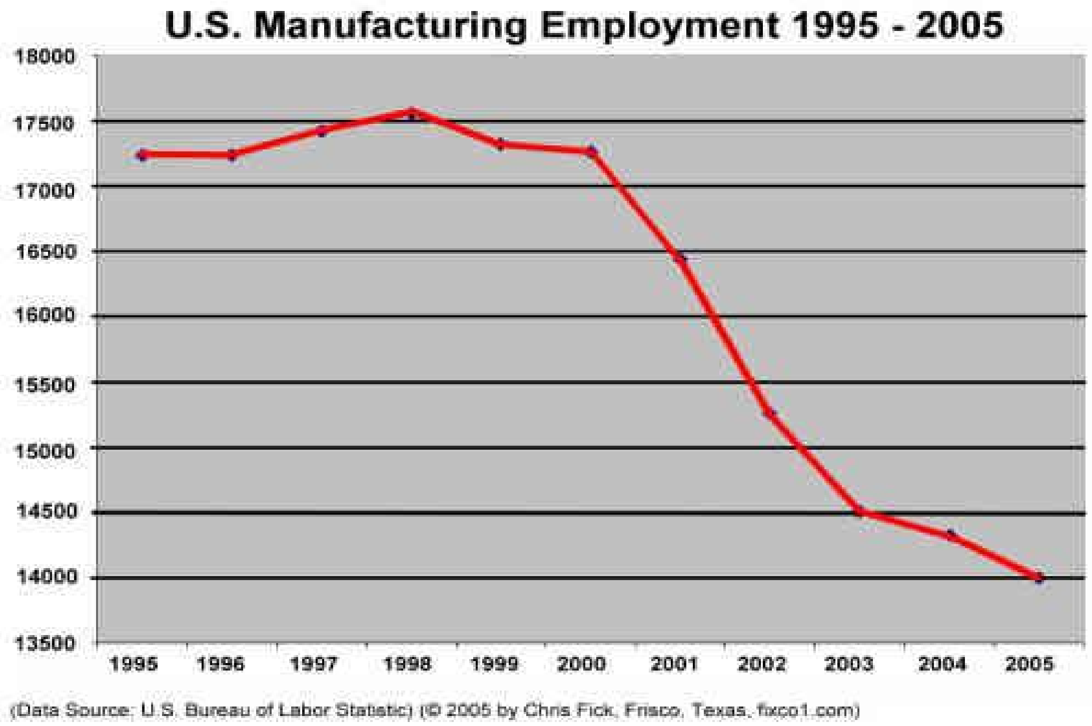
497 Zain Shauk, *Bloomberg Business Week*, "U.S. Natural Gas Exports Will Fire Up in 2015 (November 6, 2014), available at http://www.businessweek.com/articles/2014-11-06/u-dot-s-dot-natural-gas-exports-will-fire-up-in-2015.
498 EIA, *US natural gas exports to Mexico reach record high in 2012* (March 13, 2013), available at http://www.eia.gov/todayinenergy/detail.cfm?id=10351.



Nick Akins, CEO of American Electric Power accurately summed it up in testimony to the Senate Energy Committee:

> It has become clear that we are having to make a choice in the winter between committing natural gas resources to generating electricity or to heating homes. Right now, we cannot do both. Given the number of additional base load generating units that will be retired in the next 14 months, we face a real possibility that we will have to make that choice more often in the future.[499]

E. EPA Failed to Examine the Public Health and Welfare Harms that Its Regulations Will Cause by Raising Electric Rates.

The electric rate increases that EPA's proposal will cause will act as a regressive energy tax, disproportionately harming those least able to afford it. Lower income people pay a large percentage of their incomes on energy, and this percentage has been increasing over time:

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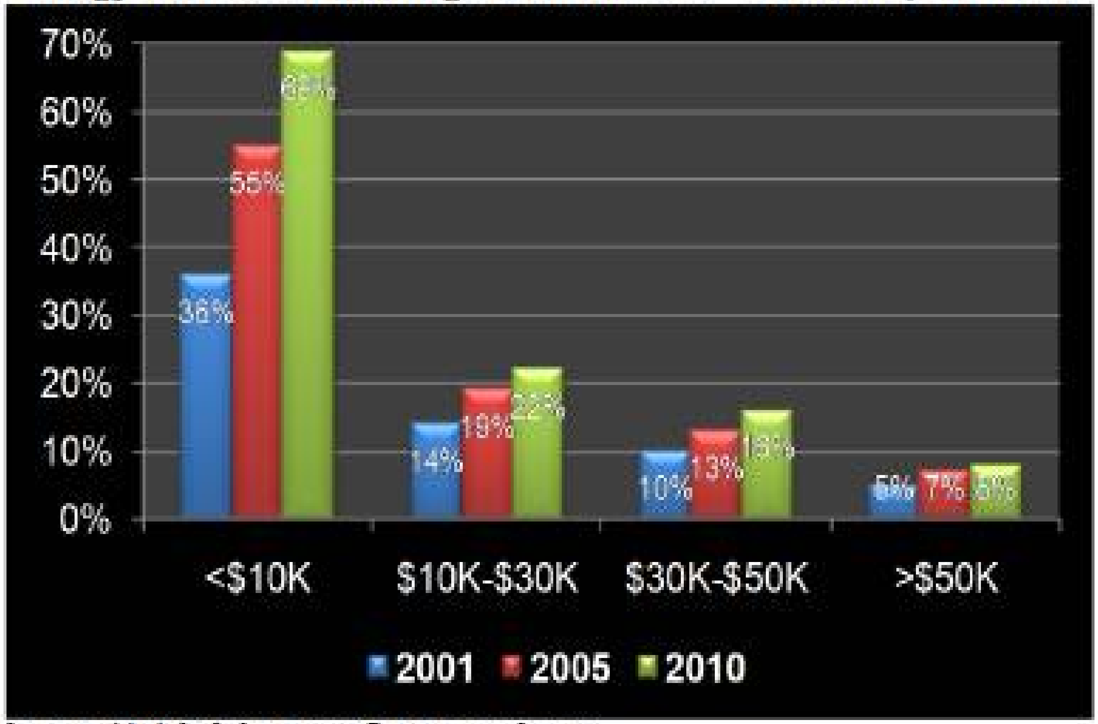
[499] *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Nick Akins, AEP, p. 10 (April 10, 2014), available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=366e6685-92f5-4878-a90f-253efa4495e8.

Figure II-29
Energy Costs as a Percentage of Annual After-Tax Income, 2001-2010



Source: 2010 BLS Consumer Expenditure Survey.

The number of people who are now vulnerable to increased energy prices is increasing. Poverty rates have increased to historic highs along with the declining long-term trend in family incomes. The number of people in poverty in 2010 was the largest number in the 52 years since the Census Bureau began to publish poverty statistics.[500] Poverty is more prevalent among some minority groups.[501] Some 27% of Blacks and 26% of Hispanics lived in poverty in 2010, compared with 15% for the overall population.[502]Nationally, between 2000 and 2012, the percentage of people in poverty increased from 12.2 percent to 15.9 percent, while the number of people in poverty increased from 33.3 million to 48.8 million.[503] The percentage of people in the United States with income below 50 percent of the poverty thresholds grew from 5.0 percent in

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[500] Eugene Trisko, ENERGY COST IMPACTS ON AMERICAN FAMILIES, 2001-2012, Feb. 2012, available at www.americaspower.org.
[501] *Id.*
[502] *Id.*
[503] U.S. Census Bureau, Poverty: 2000 to 2012, Sept. 2013.

2000 to 7.0 percent in 2012.[504] Over this period, the percentage of people with income below 125 percent of the poverty thresholds grew from 16.5 percent to 20.8 percent.[505]

Increased energy costs to lower income people cause not just economic harm but harm to their health as well. Studies show that greater use of coal-fueled electricity helps free up a family's disposable income for good nutrition, quality medical care and other smart lifestyle choices that lead to improved health. A 2002 study by researchers Daniel E. Klein and Ralph L. Keeney found that coal prevents at least 14,000 to 25,000 premature deaths each year due to low-cost electricity.[506] A 2007 study by Dr. M. Harvey Brenner, a professor of Health and Policy Management at Johns Hopkins University, confirmed the Klein-Keeney findings. Brenner concluded that if coal were removed from the energy mix, the result would be approximately 170,000 to 368,000 premature deaths in the United States.[507]

Similarly, jeopardizing the reliability of the grid places lives in danger through exposure to summer heat without air conditioning or winter cold without heat.

In sum, by increasing energy prices, EPA will negatively affect the public health and welfare. Contrary to EPA's obligation to comprehensively review the impacts and benefits of its proposal, however, EPA does not examine these detrimental effects.

F. EPA Failed to Examine the Effect of Its Regulations Cumulatively with Its Other Power Sector Regulations.

EPA's cost analysis is deficient because it does not examine the impact of the rule cumulatively with EPA's other power sector rules. EPA has undertaken a far-reaching regulatory program to transform the power sector by significantly reducing coal usage for

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[504] *Id.*
[505] *Id.*
[506] Daniel E. Klein and Ralph L. Keeney, "Mortality Reductions from Use of Low-Cost Coal Fueled Power: An Analytical Framework" (2002).
[507] Dr. M. Harvey Brenner, Ph.D, "Health Benefits of Low Cost Energy" (2007). *See also* Brenner, 2005, Commentary: Economic growth is the basis of mortality rate decline in the 20th century— experience of the United States 1901–2000, *International Journal of Epidemiology* 2005;34:1214–1221.

electric generation. Upon taking office, EPA formulated seven priorities, one of which was to "develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO_2, NO_2, mercury and other air toxics."[508] This goal was reiterated by EPA in the proposed Cross State Air Pollution Rule (CSAPR), where the Agency said that "[i]n furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular."[509]

As a part of its program to remake the power sector, EPA has promulgated or proposed a series of rulemakings, including CSAPR, MATS, its proposals for CO_2 performance standards for new, modified and reconstructed, and new EGUs, its coal combustion and residuals rule, its Section 316(b) water intake structures rule, and other rules. Because all of these rules affect the power sector and coal generation in particular, the impact of one rule cannot be understood without understanding the impacts of all the others. EPA recognized this in the preamble to the MATS rule, where it said that it would use the current CO_2 NSPS rulemaking to "facilitate the industry's undertaking integrated compliance strategies in meeting the requirements of these rulemakings."[510] It has not done so, however. As a result, industry is left unable to fully assess how these rules will affect it. For instance, EPA substantially understated the impact of the MATS rule, predicting that it would result in the retirement of 5 GW of coal-fired electric generation.[511] Current estimates are 10-12 times as high.[512] Yet it is impossible to know from

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508 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.
509 *Id.*
510 76 Fed. Reg. at 25,057.
511 U.S. EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, Table 3-8 at 3-19.
512 AEO2014 projects nearly 60 GW or retirements by 2016. *See* http://www.eia.gov/todayinenergy/detail.cfm?id=15031.

the RIA produced for the current rule whether these retirements are included in EPA's prediction of retirements that the proposed rule will cause or is additional to them.

A recent analysis showed the substantial EPA's regulations considered all together are having. Considered cumulatively, EPA's regulations will increase the cost of electricity and natural gas by nearly $300 billion in 2020 compared with 2012. The typical household's annual electricity and natural gas bills would increase by $680, or 35 percent, from 2012 compared to 2020, escalating each year thereafter as EPA regulations grow more stringent.[513]

EPA itself recognizes the need for cumulative analysis in an analogous situation. EPA requires that EPA reviewers of EISs under NEPA take cumulative impacts into account, including consideration of "impacts that are due to past, present, and reasonably foreseeable actions."[514] According to EPA, in assessing environmental impacts, it is necessary to assess "[t]he combined, incremental effects of human activity" rather than just the impacts of the particular action for which federal approval is sought.[515] This is based on the recognition that individual actions "may be insignificant by themselves," but that cumulative impacts accumulate over time, from one or more sources and these cumulative effects must be taken into consideration.[516]

The Council on Environmental Quality ("CEQ") also requires cumulative impact analysis in EISs. CEQ regulations require that agencies considering major actions that could affect

513 Energy Ventures Analysis, Inc., "Energy Market Impacts of Recent Federal Regulations on the Electric Power Sector," Nov. 21, 2014, available at http://evainc.com/2014/11/epa-carbon-plan-power-plant-regulations-will-cause-energy-prices-soar/.
514 U.S. Environmental Protection Agency, Consideration of Cumulative Impacts in EPA Review of NEPA Documents at 10 (May 1999).
515 *Id*. at 1.
516 *Id*.

environmental quality consider the "overall, cumulative impact of the action proposed (and of further actions contemplated)."[517]

Cumulative analysis is also required by Executive Order 12866, which provides:

> Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable*, the costs of cumulative regulations.*[518]

This requirement for cumulative analysis stems from the regulatory philosophy of Executive Order 12866 that the need for and effects of government regulatory actions should not be examined in isolation but instead on an overall and coordinated basis. The preamble to the Order found that the then current regulatory system did not work in a way that produced efficient results or regulations that were "effective, consistent, sensible, and understandable."[519] The first objective of the Order, therefore, was to "enhance planning and coordination with respect to both new and existing regulations."[520] In that vein, the main administrative provisions of the Order—an interagency Planning Mechanism, the requirement that each agency produce a Unified Regulatory Agenda and develop a Regulatory Plan, the requirement for a Regulatory Working Group and the provision for quarterly Conferences among OIRA and state, local and tribal governments—were all included to enhance coordination of any specific regulation proposed by

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517 35 Fed. Reg. 7390, 7391 (1970). It should be emphasized that CEQ does not distinguish between cumulative analysis of environmental impacts and of socioeconomic impacts. Under CEQ regulations, agencies must examine the effect of the proposed action on the "human environment." 40 C.F.R. § 1508.14 states that "[h]uman environment" shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment." While "economic or social effects are not intended by themselves to require preparation of an environmental impact statement," "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This applies to cumulative analysis: where socioeconomic effects accumulate from multiple actions, they must be assessed cumulatively, just as environmental effects must be assessed cumulatively. Thus, cumulative analysis is as relevant for examining socioeconomics as it is for analyzing environmental impacts.

518 Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993) (emphasis added).

519 *Id.*

520 *Id.*

an agency with that agency's other existing and contemplated regulations, with other regulations of other agencies, and with the President's overall regulatory priorities.[521]

The Statement of Regulatory Philosophy and Principles in Executive Order 12866 also stressed the need for coordination. This Statement provides that "[i]n deciding whether and how to regulate, agencies should assess *all* costs and benefits of available regulatory alternatives."[522] Agencies are instructed to "examine whether existing regulations (or other law) have created, or contributed to, the problem that a new regulation is intended to correct and whether those regulations (or other law) should be modified to achieve the intended goal of regulation more effectively"[523]; to "base its decisions on the best reasonably obtainable scientific, technical, economic, and other information concerning the need for, and consequences of, the intended regulation"[524]; and to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations or those of other Federal agencies."[525] Indeed, the preamble to the Executive Order states that "[t]he objectives of this Executive order are to enhance planning and coordination with respect to both new and existing regulation…."[526]

This requirement for coordinated government action based on coordinated and cumulative analysis built on the same requirement in Executive Order 12291, the predecessor order to Executive Order 12866 and the Order which first required agencies to prepare Regulatory Impact Analyses. Executive Order 12291 required agencies, in promulgating new regulations, to "tak[e] into account the condition of the particular industries affected by regulations . . . *and other regulatory actions contemplated for the future*."[527]

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521 *Id*.
522 *Id*. (emphasis added).
523 *Id*. at 51735-36.
524 *Id*. at 51736.
525 *Id*.
526 *Id*. at 51735.
527 Exec. Order No. 12,291 at § 2(e) (emphasis added).

Cumulative impact analysis is also legally required under the rulemaking provisions of the CAA where, as here, EPA has undertaken coordinated and comprehensive regulation of the power and coal sectors through a series of related rulemakings. The purpose of these CAA rulemaking provisions is both to ensure good regulatory outcomes and to protect the public's right to have adequate notice of the need for and effect of EPA regulatory action so that the public can provide meaningful comment.

In this context, section 307(d)(3) of the CAA requires that a rule be accompanied by a statement of its basis and purpose, including "the major legal interpretations and *policy considerations* underlying the proposed rule."[528] Given the policy behind EPA's power sector rules to transform the grid, EPA must provide an analysis of the consequences of this policy so that the public can comment adequately.

Additional support for cumulative analysis is found in section 318 of the CAA, which requires that the Administrator undertake an analysis of the cost of complying with various EPA actions, including rulemakings under section 111(d). Under section 318(d), such analyses "shall be as extensive as practicable" consistent with the standards set forth in that provision.[529]

In sum, absent cumulative analysis, EPA's analysis under Section 111 is deficient.

G. EPA Failed to Take Due Account of the Stranded Investment It Is Creating.

Other commenters will provide information on the extent to which EPA's regulations will subject utilities and their ratepayers to stranded investment. EPA nowhere takes into account the costs of this stranded investment. NMA notes a few obvious examples.

As noted above, EPA projects that its rule will eliminate coal generation in Arizona. Yet Arizona utilities have made significant recent investments in pollution controls. Since 1962,

[528] 42 U.S.C. § 7607(d)(3) (emphasis added).
[529] 42 U.S.C. § 7617(d).

Arizona Public Service (APS) has invested more than $467 million in air emission controls at the 1,027 MW Cholla facility, including LNB, separated OFA, fabric filters, electrostatic precipitators, and flue gas desulfurization equipment.[530] Since 2007, APS has invested over $319 million in air emission control equipment at Cholla.[531]

Similarly, since 2008, the Salt River Project Agricultural Improvement and Power District (SRP) has installed LNB and OFA to control NOx and new full-flow WFGD systems and stacks to control PM and SO2 at the 773 MW Coronado facility. SRP will have invested nearly $500 million in air emission controls between 2009 and 2014.[532]

EPA projects that its rule will reduce coal generation in Florida by 90 percent. Yet Gulf Power's 970 MW Plant Crist plant, located in Florida, completed installation of a $587 million scrubber system.[533] Duke Energy's two 628 MW Crystal River units, also located in Florida, installed scrubber systems in 2009 and 2010 at a cost of $1.4 billion.[534] EPA projects that its rule will eliminate coal generation in Mississippi, yet Mississippi Power currently has a $660 million scrubber project underway at its Plant Daniel.[535] EPA projects that South Dakota's Big Stone plant will operate at a 23% capacity factor, yet the facility is currently installing nearly $400 million in pollution control upgrades to meet EPA's regional haze requirements.[536] The Kansas Corporation has expressed concern that the rule will strand $3 billion in recent investment the

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530 Brief of APS and SRP in *Arizona v. EPA*, No. 13-70355 et al. (Ninth Cir., August 19, 2013) at 5.
531 *Id.* at 5-6.
532 *Id.* at 6.
533 *See* http://www.gulfpower.com/community/stewardship/air/plant-crist.cshtml.
534 *See* https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Florida+completes+clean+air+project+at+Crystal+River+Energy+Complex+&pubdate=05-25-2010.
535 http://blog.gulflive.com/mississippi-press-news/2014/03/plant_daniel_scrubber_project.html.
536 Kavulla Testimony at 9.

state's utilities have made in pollution controls.[537] The Virginia State Corporation Commission estimates several billion dollars of stranded costs.[538]

These examples are not isolated instances. EPA has recently adopted two major power sector air quality regulations, CSAPR and MATS, which between them are driving tens of billions of dollars of environmental compliance projects. EPA itself estimated that MATS alone would drive the installation of 20 GW of dry scrubbers, 44 GW of direct sorbent injection,102 GW of fabric filters, 63 GW of scrubber upgrades, and 34 GW of electrostatic precipitator upgrades.[539] EPA projected that the capital and operating costs of these installations would be \$9.4 billion *annually*.[540] Yet, with EPA now predicting an additional 49 GW of retirements in addition to the MATS-caused retirements,[541] a great deal of this investment is likely to be stranded. EPA's failure to even consider this stranded investment as a part of its consideration of the impacts of its proposal is arbitrary.

Additionally, by ignoring stranded investment in its proposal, EPA is denying states the ability to consider the remaining useful life of sources, in contravention of states' rights to do so under Section 111(d)(1)(B). It is perfectly rational for states, and thus consistent with Section 111(d)(1)(B), to determine that sources that have extended their useful lives by installing long-lived and expensive pollution control systems should not be required to prematurely retire and leave electric ratepayers with tens or hundreds of millions of dollars in unamortized investments.

In the NODA, EPA finally recognized the magnitude of the stranded investment issue and asks for comment on ways that "the agency," meaning EPA, could take account of the book

537 Comments on the proposed rule of the Kansas Corporation Commission at 2.
538 Comments of the Virginia State Corporation Commission at 3.
539 MATS RIA at 3-15.
540 *Id.* at 3-13.
541 Clean Power Plan RIA at 3-32.

life of the generating facility or the pollution control equipment.[542] As with the rest of the NODA, the concept on which EPA seeks comments is insufficiently formed to allow for comment. For instance, EPA does not explain whether, if a state goal would be made less stringent because of stranded investment, the state would be required to make additional and compensating GHG reductions either in 2020 or later that decade. In any event, EPA has it backwards. Under Section 111(d)(1)(B), EPA must allow *states* to take account of the remaining useful life of the regulated facilities. Thus, the only proper way for EPA to address the stranded investment issue is to permit states to exempt sources from EPA's requirements to the extent the states determine that compliance would create stranded investment.

H. EPA Far Overstates the Benefits of the Proposed Rule.

EPA has exaggerated the asserted benefits of the rule in reducing GHGs and other pollutants.

1. Asserted GHG benefits.

The GHG emission reductions that the rule will produce are minuscule compared to global emissions and so will have no impact on asserted climate change. For instance, the amount of CO_2 emission reductions that EPA predicts that the rule will create *by 2030*—545-555 million tonnes[543]— equals only about 1% of global CO_2e emitted *today*.[544] Perhaps because the impact of this reduction in emissions on asserted climate change will be so insignificant, EPA does not even attempt to estimate how the proposed rule will supposedly improve climate. As EPA says, "climate change presents a problem that the United States alone cannot solve. Even if

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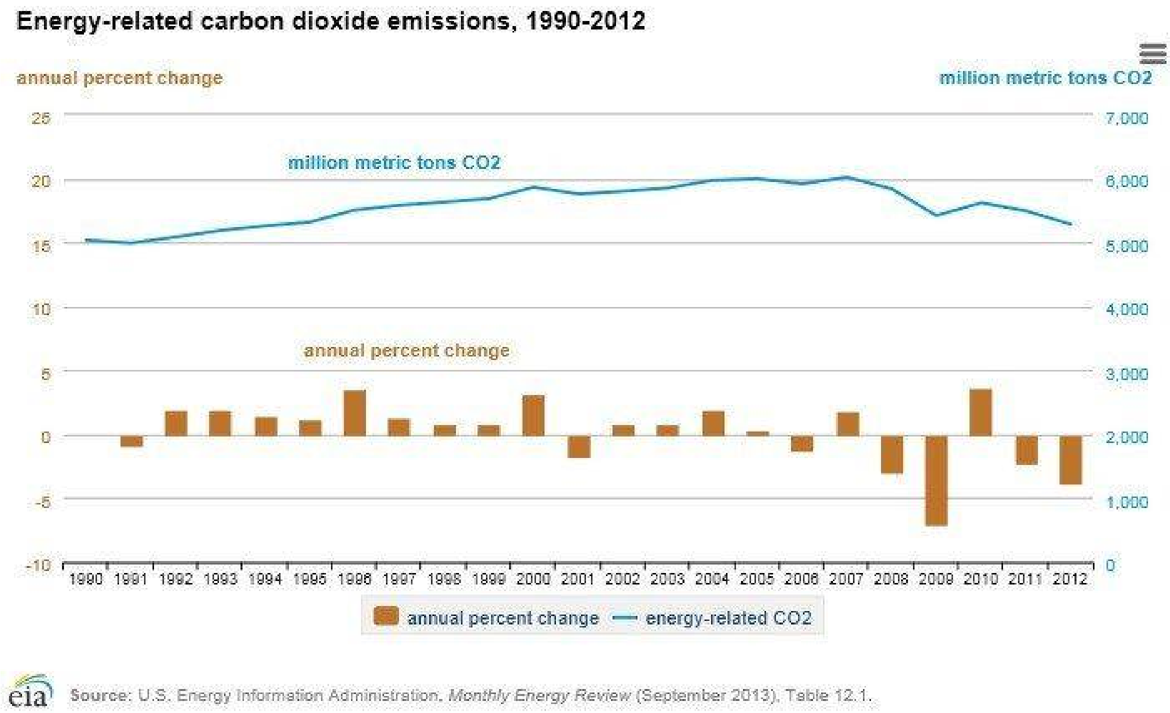
[542] 79 Fed. Reg. at 64,548-49.

[543] RIA, Table ES-2 at ES-6.

[544] The latest United Nations Environment Programme (UNEP) Emissions Gap Report estimated that global CO_2e emissions were 50.1 Gt in 2010, a figure that the report estimated had increased somewhat since then. UNEP, THE EMISSIONS GAP REPORT 2013, Nov. 2013 at 3.

the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change."[545]

The fact of the matter is that U.S. energy-sector CO_2 emissions have been declining, not increasing, and in 2013, even as emission bumped up from 2012 levels, remained below 2000 levels.[546]

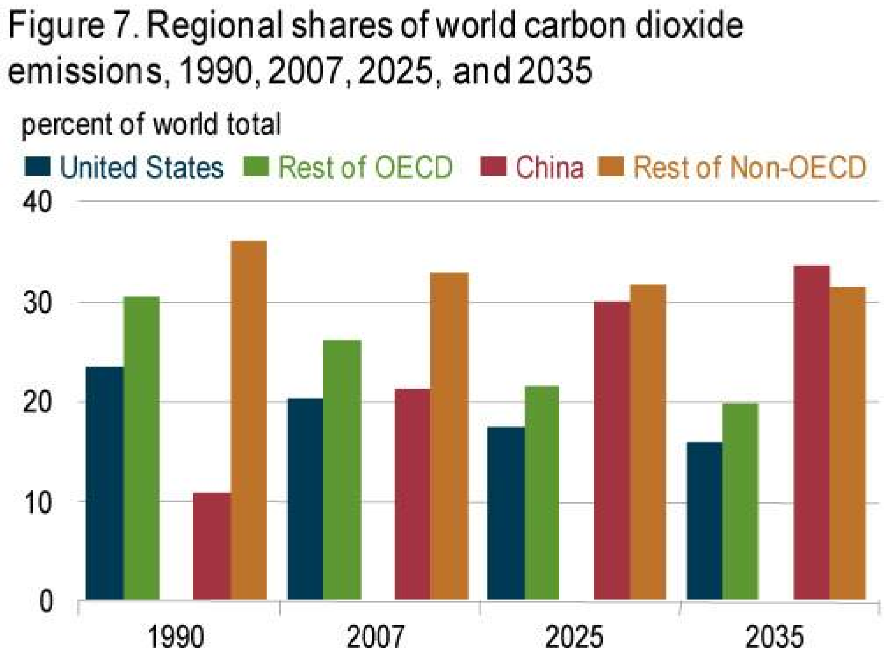


As a result, U.S. CO_2 emissions as a percentage of global emissions are falling and will decline even more in the future. According to the International Energy Agency (IEA), total incremental global CO_2 Emissions for 2011-2030 are projected to be 9,664 million tonnes, while U.S. coal incremental emissions during that period are projected to be 62 million tones.[547]U.S.

[545] EPA Social Cost of Carbon TSD at 10.
[546] EIA, U.S. Energy-Related Carbon Dioxide Emissions, 2012, October 2013 at ii and EIA, Today in Energy, January 13, 2014, .
[547] IEA, World Energy Outlook 2013.

coal-based power plants are only 0.6% of projected incremental CO_2 world emissions during that period.[548]

The following is an EIA chart showing U.S. and global CO_2 emissions. As can be seen, U.S. emissions are projected to decline as a percentage of global emissions over all time periods.



Similarly, U.S. coal production and consumption have become a relatively small share of total global coal production[549]:

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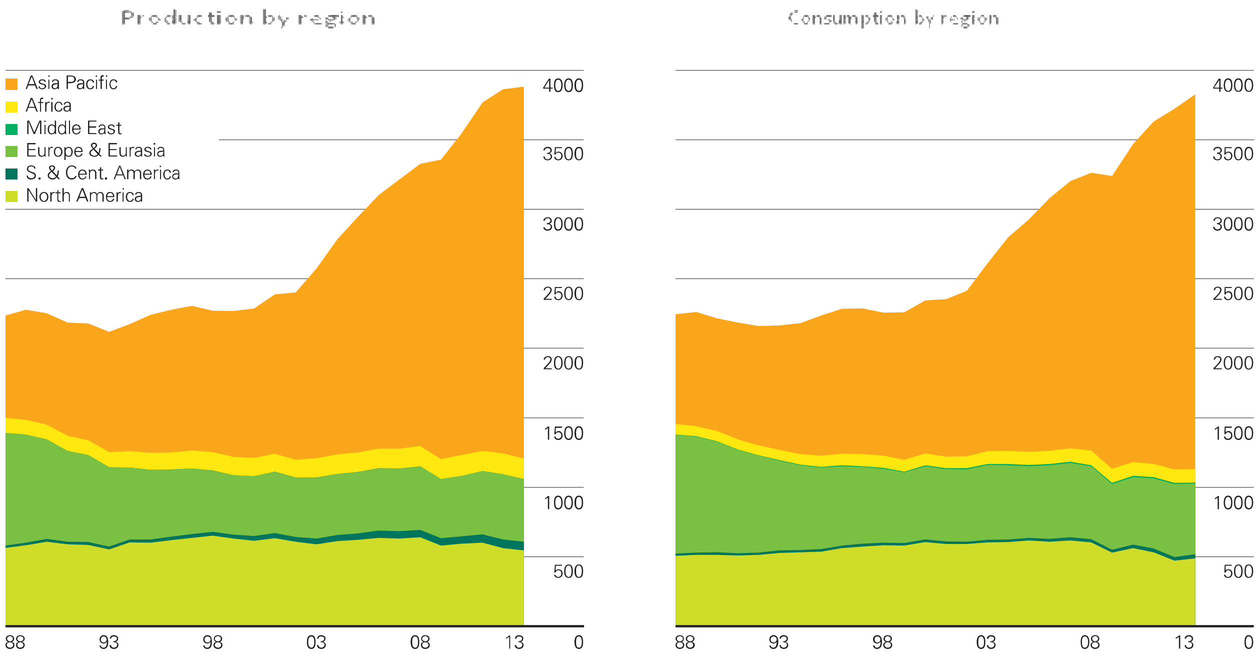
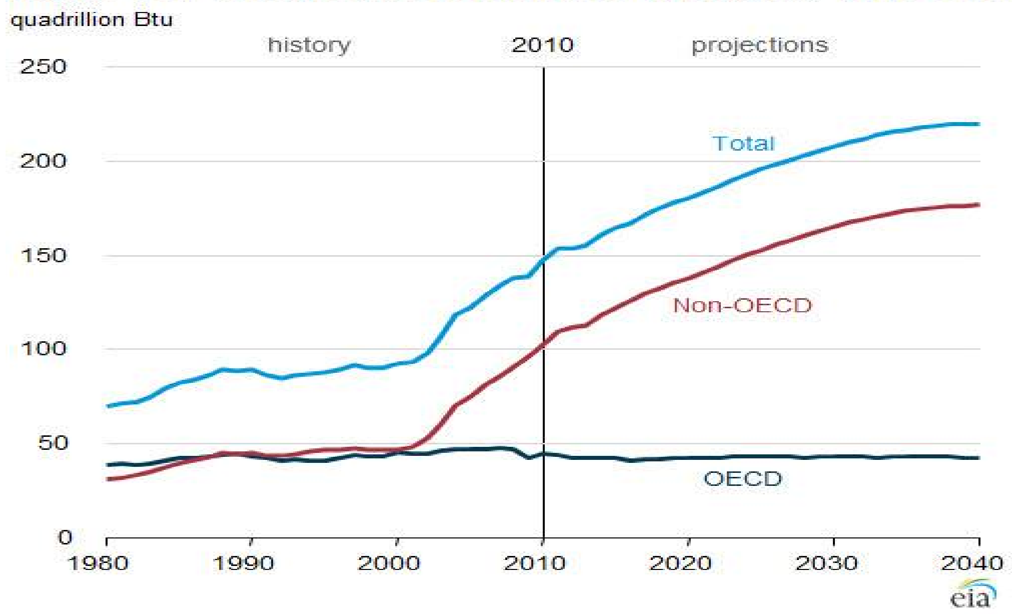
[548] *Id.*

[549] Source: BP Statistical Review of World Energy June 2014, http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy/review-by-energy-type/coal.html.



This disparity is projected to increase even more in the future[550]:

Figure 70. World coal consumption by region, 1980-2040



550 Source: EIA, International Energy Outlook 2013, Figure 70, July 25, 2013, http://www.eia.gov/forecasts/ieo/coal.cfm.

Moreover, EPA's projected CO_2 emission reductions are both overstated and misleading. EPA fails to account for increased emissions from new fossil-fueled sources needed to supply the electricity generation from base load power plants that will be closed or run at lower levels as a result of the proposed rule. On a net basis, emissions from the entire power sector will likely be only 270 to 300 million tons per year compared to the base case after accounting for the 130 to 160 million tons per year of emission increases from new fossil power sources that are exempt under the proposed rule. Essentially, EPA is trading out existing emissions for new emissions. The EVA analysis estimates that building the new emission sources will cost almost $50 billion in capital expenditures. In other words, EPA is forcing the premature closure of economically viable low cost base load power plants leaving consumers to pay for both the remaining rate recovery for the prematurely closed plants and for building new power sources to replace them.

Additionally, EPA fails to consider that its rule will encourage "carbon leakage," as energy-intensive, trade-exposed manufacturers move their facilities overseas. This leakage, which is explained in more detail in other comments, will reduce the already insignificant benefit of the proposed rule even more.

Despite not being able to estimate any real-world benefits from reducing CO_2 emissions, EPA nevertheless, using its social cost of carbon values, claims that the rule will create billions of dollars in annual benefit, as much as $94 billion in 2030.[551] These projections, however, lack credibility. Asserted climate benefits that are vanishingly small, to the point that EPA does not even attempt to describe them. These purported benefits cannot possibly have billions of dollars of annual value.

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[551] RIA, 4-12, Table 4-2.

As NMA and others have shown in other proceedings, EPA's social cost of carbon values are based on a highly flawed set of assumptions.[552] The integrated assessment models (IAMs) used to estimate the social cost of carbon have fundamental flaws that make them useless for policy analysis. Some inputs such as the discount rate are arbitrary but have substantial effects on the social cost of carbon estimates. The descriptions the models use for the impact of climate change lack any theoretical or empirical basis. Simply put, they are ad hoc. For example, a key input to the IAMs is climate sensitivity—the temperature increase that would eventually result from an anthropomorphic doubling of the atmospheric carbon dioxide concentration. Yet a critical factor in determining climate sensitivity involves feedback loops, and the values that determine the strength of those feedback loops are largely unknown, and may even be unknowable.

Because the modeler has wide latitude in choosing various inputs, the choices will produce widely different estimates of the social cost of carbon. The irony of all of this is that for those areas where the uncertainties are greatest and our knowledge is weakest, the choice of values has an outsized effect on the social cost of carbon estimates. In sum, the IAMs underlying the estimates of the social cost of carbon lack both credibility and value for supporting regulatory decisions or other policy choices.

The "calculated" benefits of the CO_2 emission reductions anticipated from the proposed rule are also inflated by going beyond the domestic benefits and including the purported global benefits. EPA's approach conflicts with OMB's Circular A-4,which calls for presentation of *domestic* benefits in a regulatory impact analysis. Any benefits outside the U.S, if calculated at all, must be presented *separately*. EPA has not offered any explanation about why this cannot be

[552] February 26, 2014 comment letter by 15 trade associations, including NMA, on the Office of Management and Budget's Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866, attached hereto.

done in accordance with Circular A-4. Rather, the agency simply states that to capture all the benefits it perceives, it is presenting a "global measure." However, the CAA is unambiguous in its purpose and focus upon the "Nation's air resources."[553] There is no basis in the law for EPA basing its policy decisions on the effects outside the U.S., let alone giving equal weight to the purported extra-territorial purported domestic benefits.

A recent analysis of EPA's social benefits of emission reductions from this proposed rule—using the methodology developed by the Interagency Working Group on SCC—finds that only 7 to 23 percent of the calculated benefits are domestic.[554] As a result, the domestic CO_2 reduction benefits are as low as $2 billion and at most $7 billion—all less than even EPA's woefully underestimated compliance costs. Finally, the purported CO_2 reduction benefits have not been adjusted for the increased emissions from new exempt fossil fueled sources that will be built due to the proposal.

2. Asserted "co-benefits."

Other commenters show that EPA's asserted co-benefits are based on emission reductions that EPA will achieve from other rules and hence EPA double-counts them. In addition, as these commenters show, the benefits that EPA asserts are produced at ambient air concentrations that are lower than the NAAQS, even though EPA set the NAAQS at a level it deemed requisite to protect the public health with an adequate margin of safety and without considering compliance costs.[555]

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553 42 U.S.C. § 7401(b)(1).

554 Ted Gayer & W. Kip Viscusi, *Determining the Proper Scope of Climate Change Benefits,* pp. 15-16 (June 3, 2014, The Brookings Institution), available at http://www.brookings.edu/~/media/research/files/papers/2014/06/04%20determining%20proper%20scope%20climate%20change%20benefits%20gayer/04_determining_proper_scope_climate_change_benefits.

555 *See* 42 U.S.C. § 7409(b); *American Trucking Ass'ns v. EPA*, 531 U.S. 457 (2001).

I. EPA's Lifecycle Analysis Is Deficient.

A major premise of EPA's proposal is that replacing large amounts of coal generation with natural gas generation will meaningfully improve the environment by reducing greenhouse emissions. As explained above, however, the CO_2 reductions that the proposal will produce are minuscule as compared with global emissions. In addition, on a lifecycle basis, replacing coal generation with gas generation will produce far fewer GHG reductions than EPA proposes. Indeed, the net impact may be to increase GHG emissions given the substantial amount of methane leakage that occurs from natural gas systems.

Some studies estimate that methane leakage rates from natural gas systems that exceed 2 percent erase any climate advantage for natural gas in the power sector over a 100-year time frame.[556] Others peg the threshold closer to 3 percent.[557] Yet, these estimates on the "breakeven" point for natural gas' advantage *precede* the most recent IPCC finding that methane is actually 34 times stronger a heat trapping gas than CO_2 over a 100-year time scale and 86 times stronger over a 20-year time scale.[558]

Recent studies on methane emissions from natural gas systems vary on their findings about the amount and percentage of methane emissions from various segments of the system. While the variability may be explained by the different scope, methodology and geography of each study, most of the recent studies indicate that overall emission rates are higher than current inventory estimates.[559] For conventional natural gas, the methane emissions from upstream (well

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556 Wigley, T.M.L., *Coal to gas: the influence of methane leakage*. Climatic Change, 2011. 108(3): p. 601-608

557 Alvarez, R. et al., Greater focus needed on methane leakage from natural gas infrastructure, Proceedings of the national Academy of Sciences, 2012, available at http://www.pnas.org/content/early/2012/04/02/1202407109.abstract.

558 2013 IPCC AR5, p. 714.

559 Howarth, Shindell et al., *Methane Emissions from Natural Gas Systems*, National Climate Assessment, Feb. Report No. 2011-003 (Table 2) (Office of Science and Technology Policy, Washington, DC) available at http://www.eeb.cornell.edu/howarth/publications/Howarth_et_al_2012_National_Climate_Assessment.pdf and attached as Appendix 6.

site) and midstream (gas processing plants) expressed as a percentage of methane produced over the lifecycle of a well range from 1-2.4 percent. For unconventional (shale) gas, the methane emissions from upstream and midstream segments is a range of 0.9-7.7 percent.[560] The methane emissions from the downstream segment of natural gas systems range from 0.07-10 percent.[561]

A recent paper published by the American Geophysical Union suggested that current bottoms-up estimates of the type that EPA relies on understate methane leakage from oil and natural systems. Their research indicates leakage rates of up to 10.1 percent.[562] Another recent paper that increased natural gas usage internationally "do[es] not discernibly reduce the trajectory of greenhouse gas emissions."[563] Still another recent study concludes that the emissions during the drilling stage for shale gas is 2 to 3 *orders of magnitude* larger than inventory estimates.[564] The mid-range of emissions from the upstream and midstream segments of unconventional gas listed in the studies discussed above exceed the two percent, and even the three percent, breakeven point for natural gas' climate advantage as compared to coal-fired EGUs over a 100 year time span. Using the IPCC's latest 34 GWP for methane makes this even more apparent.

Moreover, the supposed GHG advantage of natural gas as compared to coal dissipates even further as unconventional gas production continues to grow. Unconventional gas has higher leakage rates than conventional natural gas that matter in terms of methane emissions, and shale gas well production declines much more rapidly than a conventional well. The sharp decline is

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560 *Id*. at Table 3.
561 *Id*. at Table 1.
562 Oliver Schnesing, et al., "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations," AGU Publications, Sept. 2014.
563 Haewon McJeon, et al., "Limited impact on decadal-scale climate change from increased use of natural gas," Nature 514, 482-485 (Oct. 23, 2014).
564 Caulton, Shepson, Santoro et al., "Toward a Better Understanding and Quantification of Methane Emissions from Shale Gas Development, Proceedings of National Academy of Sciences," April 14, 2014, available at http://www.pnas.org/content/early/2014/04/10/1316546111 and attached as Appendix 7.

typically observed within the first two to three years. As a result, to maintain production in the face of more rapid decline in well productivity, new wells must be constantly drilled. With fugitive emissions occurring dominantly during well development, the shorter lifetime of a shale gas well means larger methane emissions per marketed natural gas. This reality likely explains, in part, why recent studies have found very high ambient measures of methane in shale regions regardless of leakage rates.

These are important trends and factors for EPA's consideration in assessing the efficacy of the proposed standard in addressing the stated purpose of the rule to address climate change concerns. Since unconventional natural gas will supply most of the power sector demand for natural gas, the so called "climate advantage" of natural gas EGUs over higher efficiency SCPC and IGCC appears substantially diminished, if not entirely erased.

EPA predicted that its proposal would result in a net reduction of methane emissions.[565] While EPA concedes that natural gas systems produce considerably more methane than coal mines,[566] EPA maintains that the reduction in coal production that the rule will cause will far outstrip increased natural gas production, with the result that coal mine methane emission reductions will exceed natural gas system methane emission increases[567].

EPA's conclusion is not credible. As discussed above, the electric generation emission reductions that EPA predicts by 2020 are dominated by the large-scale redispatch of coal generation to natural gas generation. According to EPA's own figures, although only 10 percent of NGCCs achieved a 70 percent capacity factor for in 2012, NGCCs in every state would be expected to achieve a 70 percent capacity factor in all years, with the exception of some states

565 RIA, Ch. 3A.
566 *Id.* at 3A-5, Table 3A-1.
567 *Id.* at 3A-7 – 3A-9.

where coal is eliminated first.[568] EPA's own RIA projects a 2020 base case of six trillion cubic feet of natural gas usage and a 2020 compliance case of 10 trillion cubic feet.[569] Obviously, this greatly increased natural gas generation must be matched by greatly increased natural gas production, which in turn will lead to greatly increased natural gas system methane emissions.

EPA's analysis fails for other reasons as well. First, EPA's choice of 2011 to compare methane emissions from coal mines and natural gas systems overstates coal emissions and understates natural gas emissions, because natural gas usage increased and coal usage declined in the 2012 base year that EPA used to calculate state goals. Second, EPA uses a GWP of 25 instead of 34 or 86 as recommended by the IPCC. Use of the higher number would magnify the difference between coal mine and natural gas system CO_2e emissions.

Finally, EPA's far-fetched projection of reduced electric consumption after 2020 depresses EPA's projection of power-sector natural gas usage. EPA's base case for its proposal shows 6 GW of NGCC generation in 2020 growing to 8 GW in 2030. But its regulatory case shows a quick ramp up to 10 GW in 2020 and no further growth through 2030. EPA projects that natural gas generation will stop growing because EPA projects that electric consumption and therefore the growth in all electric generation will decline after 2020. For instance, EPA's base case for its proposal shows natural gas growing by a healthy rate of 41% between 2020 and 2030 (799 GWh in 2020 vs. 1124 Gwh in 2030. Under the proposal, however, that growth nearly stops, declining to 2% under the regulatory scenario (1,346 GWh in 2020 vs. 1,375 GWh in 2030). This near halt in growth in gas generation is matched by a projected decline in total electric generation. In the base case, power sector generation increases from 4,104 GWh in 2015 to 4,305 GWh in 2020 to 4,702 GWh in 2030. But in EPA's regulatory case, power sector

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568 GHG Abatement Measures TSD at 3-9.
569 Figures taken from EPA's IPM spreadsheets.

generation is only 4,100 GWh in 2020 and declines to 4,051 in 2030. If EPA's improbable assumption about declining electric consumption proves wrong, as is likely based on all historical experience, NGCC generation will increase and the supposed GHG benefits of the rule will decline even further.

In sum, the rule's net impact on GHG emissions will likely be far less than EPA anticipates and may in fact will increase rather than reduce emissions.

J. EPA Has Failed to Consider the Environmental Impacts of Displacing Coal Generation with Other Generation Sources.

EPA is so focused on what it sees as the benefits of the rule that it entirely failed to examine the environmental impacts that the rule will create. EPA is projecting that the rule will displace currently-operating coal plants, which are dispatched through currently-operating transmission lines, with new natural gas and new renewable resources that will require a massive amount of new infrastructure that will in turn create its own environmental impacts. Yet EPA ignores these impacts entirely.

1. Shale gas development.

EPA is projecting a dramatic expansion of natural gas generation that will need to be met with an equally dramatic increase in the supply of shale gas. There are a number of environmental effects of increased gas production that EPA ignores, including:

- <u>Groundwater quantity and quality from increased shale gas development</u>: Shale gas production is a highly water-intensive process, with a typical well requiring around 5 million gallons of water to drill and fracture, depending on the basin and geological formation. Even with increasing volumes of water being recycled, freshwater is still required in high quantities for the drilling operations as brackish water is more likely to damage the equipment and result in formation damage that reduces the chance of a successful well. With the increasing pressure to boost well efficiencies, shale gas development demand for water grows with the development of more wells. The potential impacts also relate to pollution of groundwater with the return of injected fluids after fracturing and surface waters with the growing volumes of waste water destined for disposal.

- Air Quality impacts from shale development: Natural gas development, and in particular, shale gas development, present a range of air quality issues. Emissions occur at various stages of the natural gas supply chain and from various sources including the wells, trucks, drilling machinery, condensate tanks and compressor stations. Emissions include PM, ozone, NO_x and VOCs.[570]

- Earthquakes: A growing body of literature correlates earthquakes with hydraulic fracturing. The most recent is Paul A. Friberga, Glenda M. Besana-Ostmanb, and Ilya Drickera, "Characterization of an Earthquake Sequence Triggered by Hydraulic Fracturing in Harrison County, Ohio," Seismological Research Letters (Nov.-Dec. 2014), which attributed earthquakes in Ohio to fracturing. The paper notes previous research correlating earthquakes with fracturing, with examples that include earthquakes felt by the general population in such areas as Blackpool, England, M_L 2.3 (de Pater and Baisch, 2011), Horn River Basin, Canada, M_L 3.8 (British Colombia Oil and Gas Commission [BCOGC], 2012), and Oklahoma M_L 2.9 (Holland, 2011, 2013) and more recently in Ohio (Skoumal *et al.*, 2014). The authors concluded that "it is fairly common knowledge that fracking can cause very minor earthquakes, but a number of the ones measured and reported on in the study were substantially greater than anticipated. Hydraulic fracturing has the potential to trigger earthquakes, and in this case, small ones that could not be felt, however the earthquakes were three orders of magnitude larger than normally expected."[571]

- Impacts from building out natural gas infrastructure to meet power sector demand for natural gas: Before EPA issued its proposal, a study by ICF projected that the United States and Canada will need more than 35,000 miles of additional natural gas transmission pipelines (both mainline and laterals) through 2035 to serve anticipated growth in natural gas demand.[572] Natural gas pipelines raise the full panoply of potential environmental effects, including impacts on land, flora and fauna, endangered species, water, etc. Most new pipeline construction that requires a federal approval will trigger a requirement for an environmental impact statement.

2. Renewable resource development.

Wind and solar projects are land-intensive. For instance, it has been calculated that an 1,800 MW nuclear station requires 1,100 acres (1.7 square miles), whereas an equivalent amount of wind capacity would require 108,000 acres (169 square miles) and an equivalent amount of

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570 *See, e.g.,* Aviva Litovitz, et al., Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania, 2013 *Environ. Res. Lett.* 8 014017.

571 SNL, "Research links fracking to Ohio earthquakes," October 16, 2014.

572 INGAA Foundation, North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, March 18, 2014, at 21.

solar capacity would require 13,320 acres (21 square miles).[573] These calculations understate renewable energy land needs since the nuclear unit will operate at a 90% capacity factor, whereas the wind and solar units will operate at much lower capacity factors. EPA projects that its rule will lead to an additional 12,000 MW of renewable development by 2020, which will obviously entail the need to develop a great deal of land.[574] EPA, however, fails to examine the environmental impacts of this development.

3. Electric transmission development.

As discussed above, the development of renewable resources, as well as the development of new natural gas generation, will require thousands of miles of new transmission lines. This development will also cause environmental impacts. EPA, however, does not address the issue.

K. States Cannot Adopt the Plans EPA is Demanding within One Year, Not Even "Interim" Plans.

EPA proposes to give states one year to submit a plan or two years if states submit an interim plan in one year.[575] EPA also proposes that states that commit to a regional plan in their interim plan will have three years to submit the regional plan.[576] EPA's plan-submittal timeline, however, is unworkable. As the Kansas Corporation Commission has commented, EPA's requirement that states redesign their electric grids has such far-reaching impacts on states that they will be unable to develop a plan within one year.[577]

EPA has analogized the state plan that it is requiring here to a NAAQS SIP, yet under Section 110(a)(1) of the CAA, states are given up to three years to submit a NAAQS SIP. The three-year period recognizes the complexity involved in developing a SIP, both in terms of the

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[573] Entergy, Backgrounder, A Comparison: Land Use by Energy Source - Nuclear, Wind and Solar, available at http://www.entergy-arkansas.com/content/news/docs/AR_Nuclear_One_Land_Use.pdf.
[574] RIA at 3-34, Table 3-12.
[575] 79 Fed. Reg. at 34,915.
[576] *Id.*
[577] Comments on the proposed rule of the Kansas Corporation Commission at 21.

substantive analysis required and the need to at least hold public hearings and, in some states, for legislation.

The Section 111(d) SIP that EPA is requiring here is much more complex than a typical NAAQS SIP. Reengineering the electric grid over the long term, as EPA is demanding, will be a highly complicated, highly contentious process, with effects rippling throughout the state's economy. As a result, a much broader group of government agencies and stakeholders must be involved in developing EPA's mandated Section 110(d) state plan than are involved in developing a NAAQS SIP. While the state environmental regulator is generally the sole state agency involved in developing a NAAQS SIP, developing the type of Section 111(d) that EPA has mandated will require the direct involvement of, at least, the Governor, the state energy office, the state public service commission, and a large number of affected stakeholders, including, commercial and industrial retail ratepayer groups, renewable resource companies, demand-side management companies and a host of others who are not typically involved in developing a NAAQS SIP.

Additionally, while a limited number of states may require legislative approval of NAAQS SIPs, a much larger group of states will require legislation to implement the renewable resource and demand-side management measures that EPA is depending on to replace the coal that EPA's proposal will phase out. Virtually every state that has an RPS has one because of a legislative enactment.[578] Thus, the states that don't currently have an RPS will need legislation to enact one, and states with existing RPSs that EPA is requiring to be strengthened will need legislation for that purpose. The same is likely the case for demand-side management standards. Many state legislatures do not meet every year; many that do meet for relatively short sessions.

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[578] *See* the DSIRE website, http://www.dsireusa.org/, used by EPA to inform itself of state RPS requirements, GHG Abatement Measures TSD at 4-10.

Thus, there is little prospect that these measures could be adopted, along with all of the other requirements that EPA has mandated, within one year. As Arkansas has informed EPA, assuming, the rule is finalized in June 2015, "the General Assembly will not even meet in regular session again to consider any necessary legislation until January of 2017, when the state is scheduled to meet some of the renewable goals" and after the state's plan was due.[579]

EPA's proffered mechanism under which states would have two years to submit a final plan if they submit an interim plan within one year provides little help because the interim plan must reflect final decisions on the critical plan elements. For instance, the interim plan must include "the plan approach,"[580] presumably meaning such fundamental elements as whether the final plan will use a mass-based or rate-based approach, whether the final plan will use "portfolio" measures or will rely solely on draconian reductions in operations of coal EGUs, and whether the plan will be enforceable against third parties or just the regulated facilities. Similarly, the interim plan must include "an initial projection of emission performance that will be achieved under the complete plan."[581] In order to estimate emission reductions, the interim plan must include a full compilation of measures, perhaps subject to change, from which to estimate the reductions. The state must also include a "comprehensive roadmap" for completing the plan, including milestones such as anticipated dates for required legislative action.[582]

The state, however, is highly unlikely to know any of this information at the end of one year. For instance, a state will not know whether it can adopt an RPS of any particular amount until the state legislature adopts authorizing legislation. Without such legislation, the state

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[579]. Letter from Dustin McDaniel, Attorney General of the State of Arkansas to Avi S. Garbow, General Counsel, U.S. Environmental Protection Agency at 2 (Aug. 4, 2014), *available at* https://static.ark.org/eeuploads/ag/EPA_letter.pdf

[580] *See* proposed § 60.5760(a)(1).

[581] *See* proposed § 60.5760(a)(2).

[582] *See* proposed § 60.5760(a)(3).

cannot even submit an interim plan including an assumption that the legislature will adopt the RPS, because no state agency can know in advance what the legislature will do. Yet, as EPA has formulated the state goals, states may need to develop an RPS as a compliance strategy in order to replace the large amount of coal generation that must be eliminated for states to meet their goals. As a result, if the legislature has not acted on an RPS within one year, the state will be left unable to formulate even an interim plan that sets forth what the state's overall approach will be, what emission reductions the state will make, and what the milestones for final completion of the plan will be. And the notion that a state agency can represent to a federal agency when the state legislature will take action on any particular provision is absurd.

The interim plan approach also doesn't work because it is dependent on EPA taking final approval/disapproval action. Having submitted an interim plan, a state will need to know quickly whether EPA will approve the plan, in which case the state can develop a final plan, or whether EPA will disapprove the plan, in which case the state is liable to become subject to a federal plan. However, EPA's history of acting within statutory or regulatory deadlines on SIP approvals or indeed for any other CAA actions is spotty, to say the least. Based on past experience, the likelihood is that EPA itself will cause the interim plan approval process to be unworkable, as it will be unable to timely process the necessary approvals.

EPA's proposal to allow states three years to submit regional plans is even more unworkable. States wishing to participate in regional plans must nevertheless submit interim plans containing the same information as is required for states wishing a one-year extension to submit a standalone state plan.[583] Yet a regional plan is even more complex than a standalone state plan given that developing a regional plan requires layering interstate negotiations on top of the already complicated intrastate processes that must take place for a state to determine how it

[583] *See* proposed § 60.5755(c).

wishes to comply with EPA's Section 111(d) requirements. Moreover, each state will require legislative approval to enter into a regional plan and to adopt specific state elements of that plan (for instance, an RPS). Thus, states will not be able to commit to a regional approach in an interim plan absent legislation in multiple states. Given the time it will take to work out a regional approach, it is seriously doubtful that multiple legislatures can be counted on to approve those plans within EPA's three-year window for final plans, much less EPA's one-year window for interim plans.

CONCLUSION

EPA's proposal is legally invalid for multiple reasons. NMA urges EPA to withdraw it.