May 9, 2014

U.S. Environmental Protection Agency
Attention Docket ID No. EPA –HQ–OAR–2013–0495
EPA Docket Center, U.S. EPA
Mailcode: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA –HQ–OAR–2013–0495; FRL–9839–4, 79 Fed. Reg. 1,430 (January 8, 2014)

Dear Sir or Madam:

The American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, the National Association of Manufacturers, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce, (collectively, the "Associations") appreciate the opportunity to submit the following comments in response to the Environmental Protection Agency's ("the EPA's") proposed Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA –HQ–OAR–2013–0495; FRL–9839–4, 79 Fed. Reg. 1,430 (January 8, 2014) (hereinafter, the "proposed NSPS GHG rule" or "proposed rule").

The **American Chemistry Council** ("ACC") represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a $770 billion enterprise and a key element of the nation's economy.

The **American Forest & Paper Association** ("AF&PA") is the national trade association of the paper and wood products industry, which accounts for approximately 4 percent of the total U.S. manufacturing GDP. The industry makes products essential for everyday life from renewable and recyclable resources, producing about $210 billion in products annually and employing nearly 900,000 men and women with an annual payroll of approximately $50 billion.

The **American Fuel & Petrochemical Manufacturers** ("AFPM") (formerly known as NPRA, the National Petrochemical & Refiners Association) is a national trade association whose members comprise more than 400 companies, including virtually all United States refiners and petrochemical manufacturers. AFPM's members supply consumers with a wide variety of products and services that are used daily in homes and businesses.

The **American Iron and Steel Institute** ("AISI") serves as the voice of the North American steel industry and represents member companies accounting for over three quarters of U.S. steelmaking capacity with facilities located in forty-three states.

The **American Petroleum Institute** ("API") represents over 590 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

The **American Wood Council** ("AWC") is the voice of North American traditional and engineered wood products, representing over 75% of the industry. From a renewable resource that absorbs and sequesters carbon, the wood products industry makes products that are essential to everyday life and employs approximately one-third of a million men and women in well-paying jobs.

The **Brick Industry Association** ("BIA"), founded in 1934, is the recognized national authority on clay brick manufacturing and construction, representing approximately 250 manufacturers, distributors, and suppliers that historically provide jobs for 200,000 Americans in 45 states.

The **Corn Refiners Association** ("CRA") is the national trade association representing the corn refining (wet milling) industry of the United States. CRA and its predecessors have served this important segment of American agribusiness since 1913. Corn refiners manufacture sweeteners, ethanol, starch, bioproducts, corn oil and feed products from corn components such as starch, oil, protein and fiber.

The **Council of Industrial Boiler Owners** ("CIBO") is a broad-based association of industrial boiler owners, architect-engineers, equipment manufacturers, and university affiliates with members representing 20 major industrial sectors. CIBO was formed in 1978 to promote the exchange of information within the industry and between industry and government relating to energy and environmental equipment, technology, operations, policies, law and regulations affecting industrial boilers.

The **National Association of Manufacturers** ("NAM") is the largest industrial trade organization in the United States, representing over 13,000 small, medium, and large manufacturers in all 50 states. The NAM is the leading voice in Washington, D.C. for the manufacturing economy, which provides millions of high-wage jobs in the U.S. and generates more than $1.7 trillion in GDP. Its mission is to enhance the competitiveness of manufacturers and improve American living standards by shaping a legislative and regulatory environment conducive to U.S. economic growth.

The **National Oilseed Processors Association** ("NOPA") is a national trade association that represents 13 companies engaged in the production of vegetable meals and vegetable oils from oilseeds, including soybeans. NOPA's member companies process more than 1.6 billion bushels of oilseeds annually at 63 plants in 19 states, including 57 plants which process soybeans.

The **Portland Cement Association** ("PCA") represents 27 U.S. cement companies operating 82 manufacturing plants in 35 states, with distribution centers in all 50 states, servicing nearly every Congressional district. PCA members account for approximately 80% of domestic cement-making capacity

The Fertilizer Institute ("TFI") represents the nation's fertilizer industry including producers, importers, retailers, wholesalers and companies that provide services to the fertilizer industry. TFI's members provide nutrients that nourish the nation's crops, helping to ensure a stable and reliable food supply.

The **U.S. Chamber of Commerce** is the world's largest business federation representing the interests of more than 3 million businesses of all sizes, sectors, and regions, as well as state and local chambers and industry associations. The Chamber is dedicated to promoting, protecting, and defending America's free enterprise system.

INTRODUCTION AND SUMMARY OF COMMENTS

The Associations represent the nation's leading energy, agriculture, and manufacturing sectors, which form the backbone of the nation's industrial ability to grow our economy and provide jobs in an environmentally-sustainable and energy-efficient manner. Significantly, the Associations both represent and are reliant upon electric utilities, which will be directly regulated and impacted by the EPA's proposed New Source Performance Standard ("NSPS"). Additionally, the Associations have significant concerns regarding the Agency's first-ever regulation of greenhouse gas ("GHG") emissions from a source category under Section 111 of the Clean Air Act, both because of the impact these regulations will have on energy prices and reliability and because of the potential precedent-setting nature of the approach on manufacturing sectors in the future. We are also concerned that the proposed rule will apply directly to future projects of the Associations' members, including, for example, cogeneration plants owned, operated, or co-located at member facilities. The Associations are key and necessary stakeholders regarding any regulation that impacts energy and which may impact manufacturers directly or indirectly in the future. For the reasons described below, we urge the EPA to withdraw this proposal given the already significant adverse consequences of the proposal on industry, and to engage instead—if at all—in a process with all interested stakeholders as to whether and how the EPA should approach GHG regulation through NSPS before proposing rules that have an immediate and harmful impact.

As discussed below, the EPA's NSPS proposal is unprecedented not only in its policy reach, but in the significant number of compounding errors that exceed the EPA's authority under the Clean Air Act. At the outset, we have an overarching concern that the NSPS proposal crosses a line by expanding the EPA's 40-year mandate as the preeminent regulator of the environment to become a definitive regulator of energy. In this environmental regulation, the EPA is proposing to control not merely the emissions of air pollutants, but the choice of fuel and energy that a project must utilize if it is to be constructed or operated. The EPA's approach to force one type of fuel to be switched for another arises out of EPA's decision to mandate a technology for coal-fired electric generating units ("EGUs") that is neither economically nor technologically feasible on a commercial scale. In doing so, the EPA is effectively dictating both fuel choice and design choice for new EGUs, contrary to Congressional intent and the EPA's authority as a regulator of the environment, not energy. This action will have far-reaching consequences, not only for the EGUs themselves, but also for the many other industries that depend upon the energy that the EGUs provide and may one day become subject to the same types of regulations. In addition, by forcing an over-reliance on a single fuel source, the EPA is decreasing the reliability of the electric system.

Until now, the EPA has never chosen the manner in which performance standards must be met. Instead, consistent with Section 111's plain language and intent, the EPA has allowed regulated entities the flexibility to meet the standards in any way that satisfies the limitations. Here, for the first time, the EPA has proposed not only to set an emission limit, but it has left no choice regarding the technology that each facility must employ to meet that limit. In doing so, the EPA has acted arbitrarily, capriciously, and unlawfully, ignoring both the limits of its delegated authority from Congress and its own past practice.

The Associations share an interest in ensuring a level regulatory playing field for all potential energy choices. While the Associations support the EPA's environmental mission, we feel strongly that it should not expand its authority under the Clean Air Act by attempting to give preference to one type of fuel over another or—as it has done in this case—entirely phase out a source of energy. At most, such policies are the domain of Congress, not a regulatory agency charged with implementing laws that establish environmental performance standards.

Furthermore, the NSPS program is not intended to be a technology-forcing program. Instead, the EPA is required to identify and apply technologies that are "adequately demonstrated" in practice. Rather than speculating about the future development of unproven technologies, the NSPS program requires the EPA to conduct periodic reviews of its NSPS requirements, which allow it to consider new technologies after they have been successfully implemented on an industrial scale. Thus, an initial performance standard is never the EPA's only opportunity to regulate emissions from a source category. Rather than attempting to force the development of carbon capture and storage ("CCS") technology through this rulemaking, the EPA should rely on subsequent reviews to determine when, if ever, CCS technology has become adequately demonstrated and could be incorporated into NSPS regulations.

As the EPA recognizes, the unique nature of Section 111 results in a proposal that is having an immediate, on-the-ground impact on new facilities and, we believe, creates significant uncertainty for modified and reconstructed facilities despite the EPA's efforts to carve them out of the immediate impact of the proposal. Given the precedent-setting magnitude of this proposal and its immediate impact, the EPA should not proceed to propose such a rule until it first provides a full opportunity for all interested stakeholders to understand and comment on the approach. Thus, the Associations urge the EPA to withdraw and rescind the proposed rule as soon as possible. This action is necessary due to the immediate impacts of the proposal. Merely leaving it unaddressed indefinitely will cause ongoing harm to the energy sector and the economy. Following withdrawal and rescission, if the EPA wishes to consider GHG regulations under NSPS over the objections of the Associations, the Agency should proceed with an Advanced Notice of Proposed Rulemaking ("ANPR") so that the EPA may first solicit comments from all interested stakeholders and take time to fully understand the repercussions of its actions before imposing any previously unannounced obligations on the regulated community at the time of the proposal.

Beyond the EPA's proposed approach to EGUs, we urge the EPA to avoid repeating the errors in this approach for other manufacturing sectors in the future. As described below, there are distinctions between the utility and manufacturing sectors that warrant fundamentally different considerations and approaches to regulating these other sectors. The GHG emissions associated with other source categories are generally significantly lower than those from EGUs, the technologies and processes utilized are typically more complex, and the ability to switch fuels and designs is more constrained. Furthermore, most manufacturing sectors, unlike EGUs, are trade exposed and are unable to pass through the cost of compliance. Thus, should the EPA consider potential regulation of other sectors in the future, we urge it first to involve the Associations and other stakeholders at the earliest outset, prior to a proposal through an ANPR and other outreach, to avoid the immediate irreparable harm a similar proposal would cause to our industries and facilities and our ability to grow the economy and jobs.

The Associations' specific comments are summarized below:

- The EPA appropriately withdrew the 2012 proposed rule, but the Agency must clarify that any final standards of performance would not date back to the issuance of the 2012 proposal.

- The EPA is under no obligation to issue NSPS regulations for GHGs and should withdraw and rescind the proposed rule and proceed, if at all, with an ANPR.

- The EPA cannot regulate a source category under NSPS until it has first made a specific endangerment determination and significance finding, which it has not done here.

- The EPA may not use Section 111 to regulate a fuel type or design type out of existence, which its proposed rule will effectively accomplish.

- The proposed standard of performance for coal-fired EGUs does not constitute best system of emissions reduction ("BSER") because the EPA has not established that CCS technology is adequately demonstrated at a commercial scale. The EPA's reliance on inoperable projects, pilot scale CCS units, and projects receiving federal funding under the Energy Policy Act of 2005 is arbitrary, capricious, and unlawful. The EPA's conclusion that CCS is adequately demonstrated is also contrary to past conclusions by the EPA and the States regarding the economic and technological viability of CCS for commercial-scale EGUs.

- The EPA fails to fully address the technological, economic, and legal challenges associated with geologic storage of CO_2.

- The EPA offers no credible support for its conclusion that the costs associated with CCS are reasonable and can be borne by the industry.

- The EPA's proposal to regulate simple cycle turbines in the same manner as combined cycle turbines is arbitrary and capricious because the EPA misunderstands the fundamentally different role that simple cycle turbines play within the United States' energy portfolio.

- The EPA's proposal to include industrial combined heat and power ("CHP") units is arbitrary and capricious and fails to fully account for the environmental benefits that CHP offers. The EPA has several options to exclude industrial CHP units from the proposed standards of performance.

- The EPA provides no rational justification for failing to address modified and reconstructed sources.

- The proposed rule threatens to undercut the Tailoring Rule by, arguably, independently triggering applicability of the Prevention of Significant Deterioration ("PSD") and Title V rules at the statutory, rather than Tailoring Rule, thresholds.

- The EPA has not engaged in an appropriate cost-benefit or economic impact analysis to justify the proposed rule.

- The EPA should provide a multi-year compliance option for EGUs subject to the NSPS, but should not penalize EGUs by adopting a lower standard for multi-year compliance.

- The Associations agree with the EPA's BSER analysis for natural gas combined cycle ("NGCC") turbines.

- The Associations support the EPA's proposal to include an affirmative defense for malfunctions.

- Coal and Petroleum Coke are fundamentally different products, and it is arbitrary and capricious for the EPA to include “petroleum coke” within the definition of “coal.”

- If the EPA proceeds with a final rule, it must clarify that NSPS applies to individual units, not to facilities as a whole.

- The EPA must correct discrepancies that exist between the proposed Subparts Da and TTTT and ensure that the final regulations, if any, are consistent with the EPA’s intent.

- The EPA is not authorized to expand the proposed rule to include existing sources under Section 111(d) because EGUs are already subject to standards under Section 112.

- The EPA must not expand the NSPS GHG regulations to any other source category.

- The Associations’ members will be harmed if the EPA proceeds with this rulemaking and finalizes standards of performance for GHG emissions from new coal-fired EGUs.

For all of the above reasons, and as set forth in greater detail below, the EPA should immediately withdraw the proposed rule and proceed, if at all, by way of a more transparent and deliberative process of Advance Notice of Proposed Rulemaking (“ANPR”).

COMMENTS

I. THE EPA APPROPRIATELY WITHDREW THE APRIL 2012 PROPOSAL.

The Associations’ comments on the April 2012 proposal included a series of legal, technical, and factual critiques of the EPA’s proposed standards and urged the EPA to withdraw the proposal. *See* Comments of the National Association of Manufacturers, *et al.*, Comments on Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2011-0660; FRL-9654-7, 77 Fed. Reg. 22,392 (April 13, 2012) (submitted June 25, 2012). Thus, the Associations support the EPA’s decision to withdraw the April 2012 proposal. 79 Fed. Reg. 1,352 (Jan. 8, 2012). However, because NSPS regulations apply at the time of proposal, it is imperative that the EPA clarify the effect of the withdrawal. Specifically, the EPA should state that the withdrawal nullified or voided the 2012 proposal and that any standards of performance would apply, if at all, after publication of this proposed rule on January 8, 2014.

II. THE EPA IS UNDER NO OBLIGATION TO REGULATE GHG EMISSIONS UNDER THE NSPS.

Contrary to the EPA’s assertions, the Agency is under no obligation to regulate GHG emissions under the NSPS program. Thus, the Associations urge the EPA to use its discretion regarding the timing and content of its rules to gather additional data from the utility and manufacturing sectors before determining whether to regulate GHG emissions under NSPS and, if so, what standards to employ.

First, the EPA is under no obligation to regulate GHG emissions under NSPS. Instead, the Agency has discretion regarding the timing and content of its rules. The Supreme Court's decision in *Massachusetts v. EPA* is not controlling in this instance, as that case addressed the EPA's obligations under Section 202 of the Clean Air Act, not Section 111. More importantly, the case addressed the EPA's obligations regarding an endangerment determination under Section 202, not its obligations with respect to GHG regulations. 549 U.S. 497 (2007). Instead, the Court confirmed that the EPA has "significant latitude as to the manner, timing, [and] content" of its regulations. *Id.* at 553; *see also Center for Biological Diversity v. EPA*, 794 F. Supp. 2d 141, 159 (D.D.C. 2011) (affirming the EPA's discretion regarding timing of GHG regulations); *S.F. Chapter of A. Philip Randolph Inst. v. EPA*, No. 07-4935, 2008 U.S. Dist. LEXIS 27794, at *10-11 (N.D. Cal. Mar. 28, 2008) (same).

Second, Section 111 does not require the EPA to regulate GHG emissions at this time. The EPA's substantial discretion regarding the timing and content of NSPS regulations has been consistently recognized by the courts. *See, e.g. Portland Cement Ass'n v. EPA*, 665 F.3d 177, 193 (D.C. Cir. 2011); *Nat'l Assoc. of Clean Air Agencies v. EPA*, 489 F.3d 1221, 1228-30 (D.C. Cir. 2007). Likewise, the EPA has previously asserted that it has discretion to determine what pollutants to regulate under NSPS. *See* Section 111(b)(1)(B); 77 Fed. Reg. 48,433, 48,440 (Aug. 14, 2012) (declining to regulate GHG emissions from nitric acid plants); 73 Fed. Reg. 35,838, 35,838 (June 24, 2008) (the EPA has discretion to determine the pollutants it "deems appropriate" for regulation). The EPA's discretion applies equally here.

Third, neither the NSPS Settlement Agreement for Fossil Fueled Power Plants ("Power Plant Settlement Agreement")[1] nor the President's Climate Action Plan creates an obligation to complete the rulemaking. The settlement agreement is not a consent decree ordered by a court and does not purport to "limit or modify the discretion accorded EPA." *See* Power Plant Settlement Agreement ¶ 11. The EPA has already far exceeded the November 10, 2012, deadline for issuing a final NSPS for EGUs, and petitioners' sole recourse to enforce the Agreement would be to proceed with litigation on the still-pending petition for review. *Id.* ¶ 7. Likewise, the President's June 25, 2013, memorandum accompanying the Climate Action Plan did not include a date certain for a final rule, but instead directed the EPA to "issue a final rule in a timely fashion after considering all public comments as appropriate." Presidential Memorandum – Power Sector Carbon Pollution Standards (June 25, 2013).[2] Because the EPA has no deadline to complete the rulemaking, the Associations urge the Agency to fully consider all comments and to take the time necessary to ensure that final regulations, if any, are based on sound science and technology, and are capable of implementation. This is especially critical here, as the EPA's final NSPS standards for GHG emissions, if any, will influence decisions for future rulemakings for both existing sources and new sources in other source categories.

Fourth, the EPA is unfairly and unnecessarily subjecting entities covered by the new source category (and other members of the regulated community that rely on EGUs for energy) to a substantial risk of harm. Section 111 is different than other Clean Air Act provisions because

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[1] *Available at* http://www2.epa.gov/sites/production/files/2013-09/documents/boilerghgsettlement.pdf.

[2] *Available at* http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

it imposes obligations on "new sources" at the date of *proposal*. Section 111(a)(2). Thus, merely proposing a rule has immediate ramifications because new sources, as well as modified or reconstructed sources, are legally required to comply with the proposed standard even if it has not been finalized. Because legal obligations are triggered by the proposed rule, new sources face considerable uncertainty, as the terms of the proposal are subject to change when a final rule is issued. This uncertainty is particularly acute in situations such as this, where the proposed rule is unprecedented and, thus, the Agency is more likely to make significant changes before issuing a final rule. Indeed, here the EPA listed a range of issues on which it is still considering alternative regulatory schemes. *See, e.g.*, 79 Fed. Reg. at 1,447 (three potential definitions for "gross energy output"); *id.* (discussing options for gross- or net-output based standard); *id.* at 1,459 (considering alternative proposals for length of compliance period and maximum allowed concentration of chemicals). The Associations agree with the EPA that public comment can be an effective tool in selecting among alternatives, but the Agency should not do so in a proposed NSPS rulemaking. To the extent the EPA wishes to obtain feedback on such alternatives, it should withdraw the proposed rule and proceed instead with an ANPR that will not impose immediate regulatory burdens on EGU operators and other members of the regulated community that rely on EGUs for energy.

III. THE PROPOSED RULE IS UNLAWFUL UNDER THE CLEAN AIR ACT.

A. The Clean Air Act Requires a Separate Significant Contribution and Endangerment Determination for GHG Emissions from Each Regulated Source Category.

Before the EPA can regulate emissions under Section 111(b), the Agency must make an endangerment determination that is both source- and pollutant-specific. In other words, the EPA must separately find that CO_2 emissions from coal-fired EGUs and NGCC turbines "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A). The EPA cannot rely on its prior endangerment finding for light duty vehicles under Section 202(b) for two reasons. First, that finding was not based specifically on the relevant source categories here, coal-fired EGUs and NGCC turbines. Second, Section 202(a) lacks the more stringent "significance" requirement imposed by Section 111(b). Likewise, the EPA cannot rely on prior endangerment determinations under Section 111(b) because they do not address CO_2, the pollutant at issue here.

Rather than attempting to make the required endangerment determination before regulating CO_2 emissions under NSPS, the EPA erroneously asserts that it has discretion to apply a rational basis test as an alternative to the statutorily required endangerment determination. *See* 79 Fed. Reg. at 1,430. First, Section 111(b)(1)(A) is not ambiguous and leaves no statutory gap for the EPA to fill. Section 111(b)(1)(A) is clear and limits the EPA's authority under NSPS to the regulation and reduction of emissions of significant "air pollution" that "endanger[s] public health and welfare." The EPA's interpretation would give it the discretion to impose costly NSPS obligations in the absence of a significant endangerment of public health and welfare. Thus, the plain language of the statute compels the EPA to make a pollutant-specific finding of significant endangerment. However, given the fact that GHGs were not considered air pollutants until 2007, *see Massachusetts v. EPA*, 549 U.S. 497 (2007), the EPA cannot do so. The only endangerment findings applicable to these source categories were made decades before GHGs were considered a pollutant and cannot be construed to encompass CO_2 or any other GHGs. The EPA's alternative proposal to create a new subcategory TTTT is even more problematic, as the Agency has not made any endangerment finding for any pollutant from this proposed source category.

Second, the EPA's rational basis test would not be entitled to *Chevron* deference even if the statute were ambiguous. The EPA asserts that "information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category's emissions make to that air pollution" provides a rational basis for establishing NSPS. But this approach ignores the statute's "significance" requirement and replaces it with a less stringent standard based on subjective references to health and welfare impacts and the amount of a source category's contribution. An interpretation that deviates so far from the statutory requirements and lacks any substantive guiding principle lacks reasonableness and cannot be afforded *Chevron* deference, particularly given the EPA's inability to cite a single example where anything less than a source- and pollutant-specific endangerment determination was required.[3]

Third, even if the EPA were entitled to apply a rational basis test to establish an NSPS, this proposal would nonetheless be arbitrary. Despite the EPA's assertions regarding the quantity of CO_2 emitted from coal-fired EGUs, 79 Fed. Reg. at 1,455, the proposed standards will not protect public health and welfare by reducing those emissions. Indeed, the EPA acknowledges that the rule will have no effect on CO_2 emissions from fossil fuel-fired EGUs. *See id.* at 1,433 ("EPA projects that the rule will result in negligible CO_2 emissions changes . . . ."); *see also* EPA, Regulatory Impact Analysis ("RIA") at 5-1 – 2. Further, if the proposed NSPS will have no effect on CO_2 emissions, it is unnecessary and exceeds the EPA's authority under the Clean Air Act. *See* CAA § 301(a)(1) ("The Administrator is authorized to prescribe such regulations as are *necessary* to carry out his functions under this Chapter." (emphasis added)). Simply put, if the EPA is correct that economic conditions dictate that no new coal-fired EGUs will be constructed, there is no rational basis for promulgating regulations that only require emissions reductions for those sources.

As an alternative, the EPA suggests that even if its application of a rational basis test is unlawful, its rational basis analysis also qualifies as an endangerment determination under Section 111(b)(1)(A). This argument is patently absurd, given the EPA's insistence that it can conduct a rational basis test *in lieu of* an endangerment determination. Under a substantive analysis, the EPA's approach falls short. By basing its analysis on the generalized endangerment determination under Section 202(a), 79 Fed. Reg. at 1,455, 56, the EPA fails to satisfy and address the significance threshold and source-category determinations required by Congress under Section 111(b)(1)(A) of the Clean Air Act. A regulation that ignores the plain meaning of the statute is arbitrary and should not be entitled to deference. *See Ohio Pub. Emps. Ret. Sys. v. Betts*, 492 U.S. 158, 171 (1989). Further, it is unreasonable for the EPA to assert "that it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution." 79 Fed. Reg. at 1,456. In the absence of a guiding threshold or standard, the fact that fossil fuel-fired EGUs are

[3] Judicial opinions applying a rational basis standard of review to the EPA's endangerment determinations are inapposite and offer no support for EPA's assertion that it can dispense with an endangerment determination altogether. *See National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980); *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775 (D.C. Cir. 1976).

"the largest single stationary source category of GHG emissions," *id.*, provides no reasoned basis for the EPA to conclude that those emissions are significant. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins.*, 463 U.S. 29, 43 (1983). Finally, even if the EPA were to make an endangerment finding, it would be arbitrary and capricious to issue a rule that did nothing to meaningfully address the significant endangerment. *Cf. Ethyl Corp. v EPA,* 541 F.2d 1, 31 (D.C. Cir. 1976) (regulation must meaningfully address the harm identified in an endangerment determination). Here, the EPA's conclusions regarding market forces in the United States and the potential for international leakage in the form of increased coal exports demonstrate that the proposed rule will not reduce domestic (or global) GHG emissions.

B. Congress Did Not Grant The EPA Authority to Regulate One Type of Fuel or Plant Design Out of Existence.

As a practical matter, the proposed rule would prohibit the construction of new coal-fired EGUs because these units will be unable to achieve, through application of a best system of emissions reduction ("BSER"), the proposed 1,100 lbs CO_2/MWh performance standard. The EPA seeks to justify this *de facto* prohibition by asserting that coal-fired EGUs will not be constructed for unrelated economic reasons. *See generally* RIA, Chapt. 5.[4] While there may be some market forces at play, there is no doubt that the EPA's proposal would dictate fuel choices by increasing the barriers to entry into the utility market to the point that new coal-fired EGUs are not economically viable. By setting CO_2 emissions limits that are more than 25% lower than what the best performing coal-fired EGUs can attain, finalizing the proposed standard would ensure that no new coal-fired EGUs would be built, regardless of any current or future underlying economic conditions.

When enacting the Clean Air Act, Congress did not delegate authority to the EPA to dictate fuel or design choice. Instead, Section 111 provides a flexible standard that requires the EPA to consider costs, non-air impacts, and "energy requirements." The EPA cannot simply ignore these factors because it disagrees with them. In fact, a regulation that effectively bans the use of coal would be contrary to Congress' intent when it "designed this section and the entire bill, to encourage and facilitate the increased use of coal …." *See, e.g.,* H. Rep. No. 95-294 at 192. Policy considerations in favor of eliminating new coal-fired EGUs, such as the President's "Climate Action Plan," are contrary to the text and legislative history of the CAA and do not provide a lawful basis for the EPA's actions. *See* The President's Climate Acton Plan at 18 (June 2012) ("Going forward, we will promote fuel switching from coal to gas for electricity production …."). Only Congress may determine whether, as a matter of energy, economic security, or environmental policy, one type of fuel should essentially be banned. The following sections address specific concerns that the Associations have with the proposed NSPS.

[4] If the EPA were correct, the proposed rule would also be inconsistent with Executive Order 13563, which requires agencies to promote coordination, simplification, and harmonization in order to reduce costs and simply redundant, inconsistent, or overlapping regulation. If the market already ensures that no new coal-fired EGUs will be built, the proposed rule would be unnecessary under the Executive Order.

C. The Proposed Standard of Performance for Coal-Fired EGUs Does Not Reflect BSER.

The EPA's proposed standard of performance for coal-fired EGUs is arbitrary and capricious because it is based on CCS technology that has not been adequately demonstrated on a commercial scale. Under Section 111, a "standard of performance" is a

> standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

CAA 111(a).[5] To be adequately demonstrated, an emission control technology must be "shown to be reasonably reliable, reasonably efficient, and [it] can be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). To meet this standard, the EPA must rely on actual testing or operating data from the regulated sector or reliable qualitative assumptions, such as extrapolations based on a technology's performance in another sector. *See Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999); *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 642 (D.C. Cir. 1973). While the EPA may "look[] toward what may fairly be projected for the regulated future," *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-392 (D.C. Cir. 1973), its ability to do so is limited by the fact that the standard of performance takes effect immediately. Thus, the EPA cannot rely on emissions control technologies that are "purely theoretical or experimental." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 (D.C. Cir. 1973). Instead, the standards of performance must be based on control technologies that will be immediately available to the regulated sector and must take into consideration costs, energy requirements, and other factors specified in Section 111. The EPA cannot meet this standard for coal-fired EGUs, particularly in the absence of any operational commercial-scale power plants in the United States that use CCS.

1. No Commercial-Scale Coal-Fired EGU Has Ever Achieved the Proposed Standard of Performance.

Despite its claim that partial CCS is adequately demonstrated and can achieve the proposed standard of performance for coal-fired EGUs, the EPA is unable to identify a single commercial-scale EGU that can meet the proposed emission limit using CCS or any other technology. Instead, the EPA relies on a number of unfinished—and, in some cases, unstarted—EGUs, along with miscellaneous CCS projects that cannot be reasonably translated to the power sector. Further, the EPA ignores past best available control technology ("BACT") determinations and its own guidance, which uniformly conclude that CCS is not a viable option for controlling

[5] In the proposed rule, the EPA appended an additional criterion to the definition of "standard of performance"—whether the selected technology "promotes the implementation and further development of technology." 79 Fed. Reg. at 1,434. This new "technology promotion" criterion plays a significant role in the Proposed Rule. The legitimacy of this criterion is addressed in more detail below.

CO_2 emissions from coal-fired EGUs. Thus, the record unequivocally demonstrates that CCS is not an adequately demonstrated emission control technology.

a. The EPA Inappropriately Relies on Inoperable Projects and Pilot-Scale CCS Units to Assert That CCS Has Been "Adequately Demonstrated."

Despite the EPA's assertion that CCS is already an adequately demonstrated technology for coal-fired EGUs, the Associations have not been able to identify a single commercial-scale coal-fired EGU anywhere in the world that is currently employing CCS. At present, Norway's Test Centre Mongstad is the world's largest CCS test plant in existence,[6] but it is not cited in the proposed rule. In addition, Mongstad only captures approximately 100,000 tons of CO_2, a small fraction of total emissions.[7] Further, the project was subject to significant cost overruns, and plans to expand to a full-scale CCS unit were cancelled.[8] Norway's challenges with implementing CCS at the Mongstad facility demonstrate the inability to rely on CCS technology as adequately demonstrated for coal-fired EGUs and, in fact, are consistent with the difficulties faced by projects on which the EPA has relied in the proposed rule.

The EPA relies heavily on the Kemper County Energy Center, an IGCC plant that intends to use a pre-combustion capture system to supply CO_2 for enhanced oil recovery ("EOR") activities in the Heidelberg Oil Fields. *See* 79 Fed. Reg. at 1,439, 1,475. The Kemper facility remains under construction and, according to the EPA, is still only 75% complete. *Id.* Moreover, the project has been subject to cost overruns, with projected project costs doubling to more than $5 billion.[9] In addition, the project's construction permit has been invalidated by the Mississippi Supreme Court, *Sierra Club v. Miss. Pub. Serv. Comm'n*, 82 So.3d 618 (Miss. 2012), and additional litigation is likely before the facility ever becomes operational. Further, the project is uniquely tailored to conditions in Mississippi. Indeed, the Southern Company has explained that, because those conditions "cannot be consistently replicated on a national level, the Kemper County Energy Facility should not serve as a primary basis for new emissions standards impacting all new coal-fired power plants."[10]

The EPA's reliance on the SaskPower Boundary Dam Project, 79 Fed. Reg. at 1,434, is equally unavailing. While the project was projected to start in April 2014, it has suffered delays and now is not expected to come online until the end of 2014.[11] Importantly, the EPA has not

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[6] *See* MIT, Power Plant Carbon Dioxide Capture and Storage Projects, *available at* http://sequestration.mit.edu/tools/projects/index_capture.html (last visited February 12, 2014).

[7] MIT, Statoil Mongstad Fact: Carbon Dioxide Capture and Storage Project, *available at* http://sequestration.mit.edu/tools/projects/statoil_mongstad.html (last visited February 12, 2014).

[8] Mikael Holter, Norway Drops 'Moon Landing' as Mongstad Carbon Capture Scrapped, Bloomberg News (Sept. 20, 2013), *available at* http://www.bloomberg.com/news/2013-09-20/norway-drops-moon-landing-as-mongstad-carbon-capture-scrapped.html (last visited February 12, 2014).

[9] *See, e.g.*, Christa Marshall, Kemper project nears $5B, hits new delays, E&E Climate Wire (Oct. 30, 2013).

[10] *See* Eileen O'Grady and Scott DiSavino, Southern cautions on Kemper coal unit as EPA carbon model, Reuters (Sept. 20, 2013).

[11] http://www.estevanmercury.ca/article/20140416/ESTMERCURY0101/140419839/-1/estmercury/energy-needs-of-future-require-new-infrastructure(last visited April 18, 2014).

provided any performance testing data to establish that the project will work as intended. Nor can the Agency establish through this project that CCS will be economically viable at a commercial scale. The project, which has experienced cost overruns and delays, is wholly owned by the Saskatchewan government and has obtained significant funding from the Canadian government. Further, oil producers will be *paid* through government royalty rebates to use the captured CO_2 for EOR.

The EPA's reliance on Summit Power's Texas Clean Energy Project ("TCEP") and the Hydrogen Energy California ("HECA") project, 79 Fed. Reg. at 1,434, is even less justified. First, each project is still in the planning and design stage with no assurance when, if ever, the projects will be constructed. *Id.* at 1,476. HECA has been awaiting a certificate from the California Energy Commission since 2008 and still does not have a PSD permit from the EPA Region IX. Second, the primary purpose of each facility is fertilizer production, with energy generation making up only a fraction of the expected revenues.[12] Finally, HECA has not completed review under the National Environmental Policy Act ("NEPA"), and the Draft Environmental Impact Statement suggested that the project will not comply with state and local laws.[13] These questions regarding project completion and viability, as well as the fundamental differences between these EGUs and dedicated coal-fired EGUs, severely limit the relevance of these projects in determining whether CCS is an adequately demonstrated technology for coal-fired EGUs.

While the EPA cites a number of other commercial-scale facilities, none can withstand scrutiny:

- The W.A. Parish Generating Station, 79 Fed. Reg. at 1,434, is still in the planning stages and has not obtained a permit under PSD or any other program that will require the facility to capture and sell its CO_2 emissions.
- The Futuregen 2.0 project, *id.* at 1,475, is only in the planning stages and related to another failed CCS demonstration project that was cancelled due to cost overruns and design challenges.
- The Great Plains Synfuels Plant, 79 Fed. Reg. at 1,474, is a coal gasification plant that does not produce electricity and has no binding permit requirement to capture and sell CO_2. Further, the EPA provides no information regarding the costs, performance or reliability of this facility's CCS unit, or any explanation of why the technology can be transferred to a coal-fired EGU as required under Section 111. *See Portland Cement Association*, 486 F.2d at 391-92; *Lignite Energy Council*, 198 F.3d at 934.
- The Searles Valley Minerals Soda Ash Plant, 79 Fed. Reg. at 1,474, captures small amounts of CO_2 for the production of soda ash. Again, the EPA offers no information regarding the costs, performance, or reliability of the CCS unit and no justification of how the unit can be scaled up to capture the amount of CO_2 needed for a coal-fired EGU to achieve the standards of performance.

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[12] *See, e.g.*, Summit Power presentation to EPA, EPA-HQ-OAR-2013-0495-0057.

[13] Department of Energy, *Hydrogen Energy California Project: Preliminary Staff Assessment, Draft Environmental Statement*, Docket No. 08-AFC-BA (June 2013), *available at* http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf.

- The Duke Energy Edwardsport Power Station, 79 Fed. Reg. at 1,468, 1,476, is described as "CCS ready," but there are no concrete plans to use CCS at the facility, let alone *operating* experience to prove that the technology is adequately demonstrated.

Finally, the EPA cites to a number of small, pilot-scale CCS projects as evidence that CCS is adequately demonstrated:

- AEP Mountaineer. 79 Fed. Reg. at 1,474-75 (applying a 20 megawatt slip stream to a chilled ammonia CCS unit).
- AES Warrior Run Shady Point. *Id.* at 1,474 (capturing 111,000 metric tons of CO_2 [or less] from emissions slip streams for sale to food processing plants).
- Vattenfall Schwarze-Pumpe. *Id.* at 1,475 (capturing 70,000 metric tons of CO_2 from a 10 megawatt test rig).
- Barry Plant. *Id.* (capturing 165,000 metric tons of CO_2 from a 1.25 megawatt slip stream).

Although technical, environmental, or economic reasons are the basic tenets for which a technology must be evaluated to demonstrate viability, the EPA offers no information regarding the costs, performance, or operations of the CCS units associated with these pilot scale facilities. Further, these facilities capture only a small fraction of the CO_2 that would be required for a commercial scale coal-fired EGU to achieve the proposed standards of performance.[14] Finally, the EPA offers no rational basis to suggest that these pilot projects can be successfully scaled up to the commercial level, a proposition that has been questioned in other contexts. *See, e.g.*, Report of the Interagency Task Force on Carbon Capture and Storage (April 2010) at 9 ("Though CCS technologies exist, 'scaling up' these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges.").

While the pilot projects cited by the EPA may suggest some degree of optimism regarding CCS technology at some indefinite point in the future, they do not establish that CCS is "adequately demonstrated" at this time. The EPA fails to produce *any* information regarding the operation, reliability, efficiency, or costs of CCS projects, particularly at the commercial scale. Instead, the limited number of projects cited by the EPA underscores the remaining challenges regarding implementation, costs, and technology transfer that have thus far prevented the successful operation of a single commercial-scale CCS unit at a coal-fired EGU. Further, given the frequency with which proposed coal-fired EGU projects have been cancelled in the recent years of regulatory uncertainty,[15] the EPA's reliance on unfinished projects—particularly those in planning stages—is misplaced.

Thus, the information upon which the EPA relies confirms that CCS, rather than being "adequately demonstrated," remains an emerging technology at best. *See Sierra Club v. Costle,*

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[14] For example, the Barry Plants' 165,000 metric tons of captured CO_2 is still less than 10% of the 2.2 million tons of CO_2 that a 600 megawatt coal-fired EGU would need to capture and store annually in order to achieve the proposed emissions limits.

[15] *See* EPA, Regulatory Impact Analysis, EPAHQ-OAR-2011-0660-0024 (less than half of coal plants that obtain PSD permits commence construction); 77 Fed. Reg. 22,422 n.66 ("Since 2008, some 15 proposed coal-fired power plants with approved PSD permits have cancelled plans to construct…."); MIT, Carbon Capture and Sequestration Program (two thirds of announced CCS projects have been cancelled or put on hold).

657 F.2d 298, 341 n.157 (D.C. Cir. 1981) (recognizing inherent tension between adequately demonstrated and emerging technologies). In *Sierra Club*, the court found that dry scrubbing was not adequately demonstrated due to: (1) the absence of full scale dry scrubber use at utilities (as opposed to prototype or pilot scale units); (2) the EPA Administrator's failure to explain how pilot scale testing "may be used to predict performance in full scale plants throughout the industry;" and (3) the absence of test data for different types of coals. *Id.* Yet, that technology was far more advanced than CCS, as dry scrubbers were already installed at three facilities, with contracts in place for the installation of dry scrubbers at five additional facilities. *Id.* at 325 n.74. Here, the complete absence of commercial-scale CCS at coal-fired EGUs establishes that CCS is not adequately demonstrated, but at best an emerging technology and, thus, cannot qualify as BSER under Section 111(b).

b. The EPA and the States Have Consistently Found That CCS Is Not a Viable Technology for the Power Sector in BACT Analyses.

The EPA's conclusion in the proposed rule that CCS is adequately demonstrated for purposes of Section 111 is fundamentally inconsistent with the treatment of CCS under the PSD program, where CCS has been uniformly rejected as the BACT. A BACT analysis requires "the maximum degree of reduction" for regulated air pollutants, CAA § 169(3), and involves an exhaustive source-specific analysis that starts with the presumption that the most stringent available emissions reduction technology available should be applied unless it is eliminated for technical, environmental, or economic reasons. *See* 1990 NSR Draft Manual at B.2-B.3, B.5. In contrast to the source-specific BACT approach, NSPS is applied broadly to all new sources in a category and, as a result, serves as the "floor" for BACT analyses. *See* 40 C.F.R. § 52.21(b)(12) ("In no event shall application of best available technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 C.F.R. parts 60 and 61."). Thus, if CCS were to be deemed BSER under Section 111, it would automatically qualify as BACT in PSD analyses. However, to date, the EPA and the states have uniformly rejected CCS as BACT.

Prior to this proposed rule, the EPA has consistently found, as a practical matter, that CCS was *not* a technologically feasible or cost effective control technology. As recently as May 2011, in its PSD and Title V Permitting Guidance for Greenhouse Gases ("GHG Guidance"),[16] the EPA concluded that energy efficiency was the only available option to control GHG emissions from stationary sources:

> While energy efficiency can reduce emissions of all combustion-related emissions, it is a particularly important consideration for GHGs since *the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-derived pollutants*. Initially, in many instances energy efficient measures may serve as the foundation for a BACT analysis for GHGs, *with add-on pollution control technology and other strategies added as they become more available*.

[16] *Available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

GHG Guidance at 29 (emphasis added). While the EPA encouraged permit writers to include CCS under Step 1 of the BACT analysis, it recognized that "case-specific factors, such as the technical feasibility and cost of CCS technology" would likely require its elimination under Step 2 or Step 4 of the BACT analysis. *Id.* at 32.

Under Step 2, which addresses technological feasibility, the EPA explained that it "does not believe that at this time CCS will be a technically feasible BACT option in certain cases" due to challenges related to offsite land acquisition, funding, lack of transportation infrastructure, and the need for long-term storage. *Id.* at 36. Likewise, under Step 4, the EPA recognized that the costs of CCS would be prohibitive in most, if not all cases. *Id.* at 42-43 ("[W]e expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of captured CO_2 near the power plant is feasible."). Instead of encouraging permit writers to adopt CCS as BACT, the EPA could only speculate that "[a] number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future." *Id.* at 35. However, as described below, the EPA's subsequent evaluations of draft PSD permits make clear that this change has not yet occurred.

Since the EPA first required PSD permits for GHG emissions in the Tailoring Rule, *see* 75 Fed. Reg. 31,514 (June 3, 2010), permit writers have uniformly rejected CCS after concluding that it is technologically infeasible, prohibitively expensive, or both. The EPA has uniformly supported these decisions. For example, when the Michigan Department of Environmental Quality ("MDEQ") issued a PSD permit for two 300 MW circulated fluidized bed boiler units at the Wolverine Power Rogers City plant, it rejected CCS in its BACT analysis. MDEQ cited logistical issues related to long-term sequestration and the CCS unit's 20% parasitic energy load as reasons for rejecting CCS.[17] The EPA's comments on the draft permit did not question MDEQ's analysis of CCS.[18]

The Iowa Department of Natural Resources ("Iowa DNR") reached similar conclusions for two PSD permits. When it issued a PSD permit for the George Neal—North facility, a 525 MW pulverized coal boiler, it concluded that existing CCS technology was too costly, while more efficient CCS systems were not technologically feasible.[19] The agency highlighted the transport costs associated with suitable geologic storage sites as a key impediment to CCS.[20] Likewise, when it issued a PSD permit for Indianapolis Power & Light's Ottumwa Generation Station, a 730 MW pulverized coal boiler, the Iowa DNR rejected CCS as technologically infeasible and prohibitively expensive. Again, the agency highlighted the transport costs associated with suitable geologic storage sites as a key impediment to CCS.[21] The EPA reviewed

[17] MDEQ, Wolverine Power Supply Cooperative, Inc., Response to Comments Document (June 2011) at 103, 113-114, *available at*, http://www.deq.state.mi.us/aps/downloads/permits/PubNotice/317-07/Remand/317-07RTC.pdf.

[18] *See*, Letter from Pamela Blakely, EPA, to Mary Ann Dolehanty, MDEQ (May 19, 2011), *available at* http://www.epa.gov/nsr/ghgdocs/20110506wolverine.pdf.

[19] *Id.* at 12-13.

[20] *Id.*

[21] *Id.* at 26.

each draft permit, but did not comment on or question the Iowa DNR's conclusions regarding CCS.[22]

The South Dakota Department of Environment and Natural Resources ("DENR") reached the same conclusions when it issued a PSD permit for the Hyperion Energy Center, a 400 MW IGCC plant, and found CCS to be technologically infeasible. It cited the lack of a suitable CO_2 sequestration site and excessive transport costs,[23] as well as parasitic load of approximately 75% of electricity generation,[24] as grounds for rejecting CCS. Again, the EPA did not comment on or question the DENR's conclusions regarding CCS.[25]

Likewise, when the Illinois Environmental Protection Agency ("IEPA") issued a PSD permit for the Taylorville Energy Center, a 716 MW IGCC facility, it concluded that CCS "is not yet adequately demonstrated so as to be able to definitively determine that it would be technically feasible when the plant begins operation…."[26] IEPA also cited several logistical challenges to CCS, including access to CO_2 pipelines, locating a suitable sequestration site, and property right issues associated with geologic storage.[27] In its comments on the draft permit, the EPA stated for the first time that it "generally considers CCS to be an available control technology."[28] However, the EPA did not disagree with IEPA's conclusion that CCS was not available for the Taylorville facility.

The significance of these permitting decisions—and the EPA's acquiescence—cannot be overstated. Each time an agency has evaluated CCS in a facility-specific context, it has concluded that a variety of technological and economic factors made CCS unavailable. Each time, the EPA has agreed that CCS was not appropriate. Yet, if the proposed standard of performance is adopted, CCS will become a mandatory floor for all future PSD permits for new coal-fired EGUs. *See* 1990 NSR Manual (Draft) at B.12 ("NSPS simply defines the minimal level of control to be considered in the BACT analysis."). Given the consistent rejection of CCS

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[22] *See* Letter from Mark A. Smith, EPA Region 5, to Dave Phelps, Iowa Dep't of Natural Resources (May 6, 2011), *available at*, http://www.epa.gov/nsr/ghgdocs/20110506midamerican.pdf; Letter from Mark A. Smith, EPA Region 5, to Dave Phelps, Iowa Dep't of Natural Resources (Dec. 19, 2011), *available at* http://www.epa.gov/nsr/ghgdocs/20111219ottumwa.pdf.

[23] South Dakota Department of Environment and Natural Resources, Statement of Basis Construction Deadline Extension Request for the Prevention of Significant Deterioration Permit # 28.0701-PSD at 37-40 (May 2011) at 48, *available at* http://denr.sd.gov/Hyperion/Air/20110502ResponseToComments.pdf.

[24] *Id.* at 38.

[25] *See* Letter from Deborah Lebow Aal, EPA, to Brian Gustafson, DENR (Apr. 1, 2011), *available at*, http://www.epa.gov/nsr/ghgdocs/20110401hyperionrefinery.pdf

[26] IEPA, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application for the Taylorville Energy Center in Taylorville, Illinois (April 2012) at 4, *available at*, http://www.epa.state.il.us/public-notices/2011/christian-county-generation/responsiveness-summary.pdf; *see also id.* at 113 ("the information provided by CCG in the Application, as well as the IEPA's independent analysis as reflected in the Project Summary, supports the conclusion that at this time CCS is not technically feasible for control of CO_2 emissions….") (footnote omitted).

[27] *Id.* at 114.

[28] Letter from Genevieve Damico, EPA, to Ed Bakowski, IEPA (Dec. 29, 2011), *available at*, http://www.epa.gov/nsr/ghgdocs/20111229christian.pdf.

under BACT analyses, it would be arbitrary and capricious for the EPA to now conclude that CCS is adequately demonstrated for purposes of Section 111 and, therefore, applicable to all future PSD permits.

c. Carbon Capture from Natural Gas Streams Cannot Establish That CCS Is Adequately Demonstrated for Coal-Fired EGUs.

Finally, the EPA points to the natural gas industry's experience with CO_2 capture to justify the technical feasibility and availability of CCS. *See* 79 Fed. Reg. at 1,471 ("Capture of CO_2 from industrial gas streams has occurred since the 1930s, through the use of a variety of approaches to separate CO_2 from other gases."); *id* at 1,479 ("Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry ….”). However, the natural gas industry's historical use of amine absorption processes to separate CO_2 from natural gas steams is significantly different from the processes needed to capture CO_2 from power plant combustion stacks. First, the two processes require different amines because carbon capture from natural gas streams occurs at high pressure, while CO_2 capture from flue gas does not. Second, natural gas streams are relatively pure, with little variability in temperature, pressure, solubility, and other characteristics. In contrast, flue gas combustion streams contain particulate matter, sulfur dioxide, nitrogen oxides, and oxygen and have variability in temperature, solubility, and other characteristics. Due to these significant differences, there is no basis for the EPA to assume that technologies and processes used by the natural gas industry can be transferred to coal-fired EGUs for carbon capture.

2. Recent CCS Studies Do Not Support the EPA's Conclusion That CCS Is Adequately Demonstrated.

In addition to the specific CCS projects discussed above, the EPA relies on "an extensive literature record," 79 Fed. Reg. at 1,471, to support its conclusion that CCS is adequately demonstrated. However, the three government studies the EPA cites do not support a finding that CCS is adequately demonstrated.

First, the Report of the Interagency Task Force on Carbon Capture and Storage unequivocally states that CCS is not adequately demonstrated. Task Force Report at 34 ("CO_2 removal technologies are not ready for widespread implementation on coal-based power plants, primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application."). In particular, the Task Force Report was critical of the costs associated with CCS. *Id.* at 8, 29, 33, 35. Nevertheless, the EPA inexplicably relies on the report when asserting that "there are no insurmountable technological, legal, institutional, regulatory, or other barriers that prevent CCS from playing a role in reducing GHG emission." 79 Fed. Reg. at 1,471. But, putting aside the veracity of the EPA's conclusions, the lack of "insurmountable" barriers to CCS does not establish that CCS is adequately demonstrated. In fact, the Task Force Report directly contradicts the conclusion that CCS is adequately demonstrated. The purpose of the Task Force was to "propos[e] a plan to overcome the barriers to widespread, cost-effective deployment of CCS within 10 years …." Task Force Report at 7. But, nearly halfway into that 10-year period, there are no commercial-scale demonstration projects that have commenced operations. Finally, the report was available to the EPA when it issued the GHG Guidance in

2011, yet the EPA offers no rational basis for reversing its prior conclusion that CCS was unlikely to meet the higher BACT standard. *See Jicarilla Apache Nation v. Dep't of the Interior*, 613 F.3d 1112, 1119 (D.C. Cir. 2010) ("One of the core tenets of reasoned decisionmaking announced in *State Farm* is that an 'agency changing its course … is obligated to supply a reasoned analysis for the change.'" (alteration in original) (citations omitted)).

Second, the 2009 Pacific Northwest National Laboratory ("PNNL") study, "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009," offers no support for the EPA's conclusion that CCS is adequately demonstrated. At most, the PNNL study suggests that existing CCS projects could "meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants…." PNNL Study at 1.[29] However, the PNNL study never attempts to contribute anything beyond the "meaningful discussion" phase, and does not attempt to explain how CCS technology could transfer to commercially operating coal-fired power plants. Instead, the PNNL study calls for "a vigorous ongoing research, development and demonstration program on improving CCS technologies and demonstrating them in various combinations of technological, geographical, and geologic applications and settings." *Id.* at 2. In sum, the PNNL study treats CCS as an emerging technology that is not yet ready for widespread application in coal-fired EGUs.

Third, the National Energy Technology Laboratory's ("NETL's") Cost and Performance Study does not support the EPA's conclusion that CCS is adequately demonstrated. It does not evaluate actual CCS facilities or offer any conclusions regarding their technological feasibility. Instead, the study is a modeling exercise that estimates the costs and potential efficiencies of different coal-fired EGU configurations at a variety of CO_2 capture rates. *See*, Cost and Performance Study at 1. Thus, contrary to the EPA's assertion, the study cannot "further support [the EPA's] proposed determination of the technical feasibility of partial capture." 79 Fed. Reg. at 1,471. Taken together, these three studies merely reinforce the fact that CCS is, at best, an emerging technology in its relative infancy that is not adequately demonstrated as technologically and economically feasible for coal-fired EGUs.

Fourth, the federal government's recent study *Climate Change Impacts in the United States*[30] contradicts the EPA's conclusions regarding CCS. While the study states that CCS can reduce CO2 emissions from coal and natural gas combustion, it also notes a series of challenges associated with CCS. For example, the study explains that "CCS substantially increases the cost of building and operating a power plant, both through up-front costs and additional energy use during operation (referred to as "parasitic loads" or an energy penalty." *Id.* at 271. Ultimately, the study concludes that CCS's "demonstration at scale" remains uncertain. A technology whose demonstration at scale is uncertain cannot be adequately demonstrated.

[29] The PNNL study incorrectly states that CO_2 is currently being captured by coal-fired commercial power generating facilities. PNNL Study at 5. The only coal-fired facility addressed in the study is the Great Plains Synfuels Plant, which produces gas, not electricity, and applies a markedly different process than would be required for a coal-fired EGU. *Id.* at 9.

[30] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Changes Research Program, 841 pp. doi:10.7930/J0Z31WJ2.

3. The EPA Offers No Rational Basis for Reversing Course and Concluding That CCS Is BSER.

In the proposed rule, the EPA offers no rational basis for reversing its 2012 determination that CCS did not qualify as BSER for coal-fired EGUs. In the 2012 proposed NSPS, the EPA expressly declined to find that CCS was BSER. 77 Fed. Reg. 22,293, 22,399 (Apr. 13, 2012) ("[W]e are not stating that in this action whether [the CCS] compliance option does or does not qualify as [BSER]."). In fact, the 2012 proposal strongly suggested that CCS was not BSER. First, the EPA determined that NGCC turbines were BSER for coal-fired EGUs. *Id.* at 22,398. Second, the EPA's alternative 30-year compliance option allowed coal-fired EGUs to continue current emissions for 10 years, suggesting that CCS would not qualify as BSER until at least that time. *Id.* 22,398, 22,406-07; *see also id.* at 22,407 ("The 30-year averaging period is sufficiently long to allow sources, before they install CCS, to benefit from the experience that will be gained from commercial-scale CCS demonstration projects operating over the next decade from a number of DOE-funded demonstration projects."). The EPA's skepticism regarding CCS was further illustrated by its proposal to reevaluate "the state of commercialization of CCS technologies" eight years after the 2012 proposal. *Id.*

Despite the EPA's withdrawal of that proposed rule, the fact remains that less than two years prior to the current proposal, the EPA concluded that CCS was not adequately demonstrated for purposes of establishing BSER. That position was consistent with the EPA's GHG Guidance, other studies cited above, and the experience of both the EPA and the states in issuing PSD permits for GHG emissions. Nothing has changed since then. In fact, the EPA does not cite any new information or new projects in this rulemaking that were not available to it (and in many cases cited by it) in the 2012 proposed rule. Without some new data or evidence of changed conditions, there is no rational basis for the EPA to reverse course and conclude that CCS is adequately demonstrated and, therefore, is BSER for coal-fired EGUs. Such a conclusion is fundamentally at odds with the most basic principle of administrative law that, when an agency changes its position, it "must supply a reasoned analysis" for doing so. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 57 (1983). The fact is that nothing has changed since 2012. There are still no commercial-scale CCS facilities and, while a few projects have moved toward completion, their delays and cost overruns have been as common as their progress. In sum, there is no reason to doubt the EPA's conclusion in 2012 that CCS is not BSER.

4. It Is Unlawful for the EPA to Base Its "Adequately Demonstrated" Finding on Facilities That Received Funding Under the EPAct of 2005.

The EPA's conclusion that CCS qualifies as BSER is unlawful, among other reasons, because the EPA relies heavily on non-operating projects that have received funding through the Clean Coal Power Initiative ("CCPI"), a $200 million grant program administered by the Department of Energy to promote "clean coal" technology. The CCPI is intended to "advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated on a scale that the Secretary determines is sufficient to demonstrate that commercial service is viable…." EPAct § 402(a). Given the CCPI's focus on experimental technologies, it is not surprising that Congress recognized the program's inconsistency with establishing NSPS and prohibited the use of CCPI-funded programs to establish that a technology is adequately demonstrated:

> No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated for purposes of Section 111 of the Clean Air Act (42 U.S.C. 7411) (codified at 42 U.S.C. § 15962(i)). Section 1307 of the EPAct, outlining the treatment of tax credits for qualifying advanced coal projects, includes a nearly verbatim prohibition on the EPA Administrator's consideration of CCPI-funded projects under Section 111 of the Clean Air Act.

26 U.S.C. § 48A(g).

Thus the EPAct of 2005 prohibits the EPA from considering evidence from projects funded under the EPAct in setting "standard[s] of performance" under Section 111 of the CAA if, in the absence of such projects, the EPA cannot establish that the NSPS control technology is "adequately demonstrated." In sum, the EPA is required by statute to conduct a "but for" analysis to determine whether the control technology would qualify as BSER but for evidence from projects funded under the EPAct. If not, the EPA cannot rely on the control technology in establishing a standard of performance. Otherwise the EPA could avoid the statutory limitations imposed by Congress simply by referring generally to other non-EPAct-funded projects, even if those other projects would be insufficient to establish that the control technology qualified as BSER. Such an interpretation would frustrate Congress' purpose in passing the EPAct of 2005 and would contradict the plain language of the statute.

Therefore, when a proposed or final NSPS must rely on evidence from projects funded by the EPAct to be justified, such projects necessarily constitute the "but for" basis for the standard and are effectively the sole support for the control technology. Here, in the proposed rule, EPA does exactly what the EPAct prohibits: it seeks to avoid the prohibition on EPAct-funded projects by citing to other projects that are not funded by the EPAct, despite the fact that those other projects, standing alone, cannot justify the selection of CCS as BSER.

The Department of Energy's prior track record under the Clean Coal Technology Program further explains why Congress excluded CCPI projects from BSER determinations under Section 111. The CCPI program was essentially a revised version of the Clean Coal Technology Program that was first established in 1984 to fund research and development projects involving clean coal technologies. The Clean Coal Technology Program was largely unsuccessful, with millions of dollars unspent and many projects suffering from "serious delays or financial problems."[31] A GAO evaluation revealed that many projects were years behind schedule and, in some cases, bankrupt due to an inability to obtain additional funding.[32] Among the problems highlighted by the GAO were the selection of programs that "have proven not to be economically viable," "may

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[31] Letter from Jim Wells to Rep. Kasich, Enclosure I, Clean Coal Technology Program, Briefing for the House Committee on the Budget (Mar. 9, 2000) GAO/RCED-00-86R.

[32] *See generally* Letter from Jim Wells to Rep. Kasich, Enclosure I, Clean Coal Technology Program, Briefing for the House Committee on the Budget, GAO/RCED-00-86R.

have limited potential for achieving nationwide emission reductions when used as existing coal-burning facilities," and "may have difficulty in successfully demonstrating, and ultimately commercializing, their technologies."[33]

In response, Congress included in the EPAct of 2005 a requirement that the Secretary of Energy submit to Congress "a detailed description of how the program will avoid problems enumerated in Government Accountability Office reports on the Clean Coal Technology Program." EPAct § 401(b)(4). Given the history of the Clean Coal Technology Program, it is not surprising that Congress did not want the EPA to rely on CCPI projects, particularly those that had not yet been completed. This caution is well-grounded. Of the 18 CCPI-funded projects thus far, only 4 have been completed, while 10 have been withdrawn or discontinued. Likewise, in the 2012 proposal, the EPA touted 6 "transitional sources" that were planning to install CCS with the use of a DOE CCS loan guarantee or grant. 77 Fed. Reg. at 22,422. In less than two years, 5 of the 6 facilities[34] were cancelled, switched to natural gas or otherwise halted progress.

Despite the prohibition on considering such sources, the EPA unlawfully relied on five proposed facilities that have received CCPI funding: Kemper County Energy Facility, 73 Fed. Reg. 54,569 (Sept. 22, 2008); TCEP, 76 Fed. Reg. 15,968; HECA, 78 Fed. Reg. 43,870 (July 22, 2013); W.A. Parish, 78 Fed. Reg. 30,901 (May 23, 2013); and Mountaineer. 75 Fed. Reg. 32,171 (June 7, 2010). After publication of the proposed rule, the EPA issued a Notice of Data Availability ("NODA") that acknowledged the EPAct's prohibition on considering projects that received CCPI funding. 79 Fed. Reg. 10,750 (Feb. 26, 2014). However, the EPA claims that it is free to consider CCPI-funded projects so long as it "does not depend solely upon those projects, and the [adequately demonstrated] determination remains adequately supported without any information from" CCPI-funded projects. NODA at 10. The EPA is incorrect for several reasons. First, the EPA is prohibited from applying a technology or level of emission reduction as BSER when CCPI-funded projects are the "but for" justification of the Agency's decision. That is what the EPA has done here. Second, and in addition, the NODA also mischaracterizes the content of the EPAct. In the NODA, the EPA focuses on "projects," *id.*, that will use CCS technology, instead of focusing on the "technology" or "levels of emission reductions" as required by the EPAct. The distinction is important. Although the EPA has referenced a handful of non-CCPI-funded projects, it has relied solely on CCS—a CCPI-funded technology—to determine the proposed standard of performance for coal-fired EGUs. This is contrary to the EPAct and, therefore, unlawful.

The EPA's expansive interpretation of the word "solely" creates a loophole so large that it essentially swallows the rule. The EPA asserts that, while it cannot rely exclusively on CCPI-funded projects, the projects can "provide part of the basis for" an adequately demonstrated determination.[35] In other words, according to the EPA, as long as the Agency can point to some

[33] GAO, Lessons Learned in the Clean Coal Technology Program, GAO-01-854T, Statement of Jim Wells, Dir., Nat'l Res. & Env't (June 12, 2001) ("Wells Test.") at 4-5.

[34] The five facilities are Taylorville Energy Center, Trailblazer Energy Center, Good Spring, Power County Advanced Energy Center, and Cash Creek Generation Plant.

[35] EPA, Technical Support Document: Effect of EPAct2005 on BSER for New Fossil Fuel-fired Boilers and IGCCs at 13 (Jan. 8, 2014), *available at* http://www2.epa.gov/sites/production/files/2014-01/documents/2013_proposed_cps_for_new_power_plants_tsd.pdf.

other shred of supporting evidence, it is permitted to rely on CCPI-funded projects to show that a control technology is adequately demonstrated under Section 111(b).

This contorted interpretation of the EPAct is *clearly* contrary to the statute and to Congressional intent as described above and places virtually no limit on the EPA's ability to rely on CCPI-funded projects. Indeed, that is the case here. Despite attempts to marginalize the importance of the CCPI-funded projects, the EPA is ultimately forced to acknowledge that it relied "prominently" on the Kemper County Energy Facility, TCEP, and HECA projects to establish that pre-combustion capture of CO_2 is technically feasible. Technical Support Document at 20. Without these CCPI-funded projects, the EPA is left to rely on a handful of small-scale pilot studies, projects that have not begun operations, miscellaneous sources that do not produce electricity, and a few studies that do not support CCS. In light of the uncertainty in completing proposed projects, scaling up demonstration projects, and transferring technology to new source categories, these projects are wholly insufficient to show that CCS is adequately demonstrated. Thus, it is clear that the EPA's references to CCPI-funded projects do not merely "corroborate an otherwise supported determination." NODA at 10. Instead, the projects form the central foundation of the EPA's determination that CCS is adequately demonstrated. It is contrary to the plain meaning and intent of the EPAct for the EPA to place such a degree of reliance on projects that receive CCPI funding.

5. The EPA Does Not Address Challenges Associated with Geologic Storage of CO_2.

a. The EPA Fails to Support Its Conclusion that Captured CO_2 Can Be Sold for EOR.

The EPA offers virtually no support in the proposed rule for its assumption that coal-fired EGUs installing CCS technology will have access to UIC Class II EOR[36] wells or UIC Class VI geologic storage wells. *See* 79 Fed. Reg. at 1,482 ("[F]or the immediate future, virtually all of the CO_2 captured at EGUs will be injected underground for long-term geologic sequestration at sites where enhanced oil recovery is also occurring."). While the EPA includes an extensive technical discussion of EOR, *id.* at 1,473-74, it offers no analysis of the projected growth of EOR or the potential demand for anthropogenic CO_2 captured from coal-fired EGUs. In fact, there are very few active EOR wells clustered in a few geographic areas,[37] and, as explained above, states evaluating CCS in PSD BACT analyses frequently reject it due to a lack of viable geologic storage options. In light of this past experience, it is arbitrary and capricious for the EPA to assume that EOR opportunities will be available without conducting a more thorough market analysis.

The EPA's assumptions in the proposed rule are also contrary to the EPA's contemporaneous determinations in PSD permitting decisions where the Agency has refused to assume that new stationary sources would be able to sell captured CO_2 to nearby EOR wells. EPA, Response to Public Comments, Celanese Clean Lake Plant (Dec. 12, 2013) at 23 ("Just

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[36] While the EPA uses the term "EOR," "ER" may be a more appropriate term as it encompasses both enhanced oil and gas recovery.

[37] http://energy.gov/fe/science-innovation/oil-gas/enhanced-oil-recovery.

because a company can recover CO_2 does not mean they have a contractual customer or partner willing to purchase the CO_2. The commenter first assumes that Denbury Resources would purchase Celanese's captured CO_2 emissions, but there is no evidence that this is the case."); *see also* EPA, Response to Public Comments, ExxonMobil Chemical Company Baytown Olefins Plant (Nov. 25, 2013) at 11 (same). The EPA offers no rational basis for taking these fundamentally inconsistent positions. *See Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 57.

Further, even where EOR may be technically available, the EPA is proposing a regulatory structure that will discourage the use of captured CO_2 in comparison to the naturally occurring CO_2 that is currently used for EOR. First, the proposed rule would require any well operator injecting captured CO_2—including EOR well operators—to comply with the GHG reporting requirements under Subpart RR (40 C.F.R. § 98.440, *et seq.*). *See* 79 Fed. Reg. at 1,483. As a result, EOR well operators who could otherwise report under Subpart UU (40 C.F.R. § 98.470, *et seq.*) would be subject to more onerous reporting requirements, including the adoption of a monitoring, reporting, and verification ("MRV") plan that requires the EPA's approval, oversight, and potential revisions over time. *See* 40 C.F.R. § 98.448. EOR well operators may seek to avoid MRV requirements for a number of reasons. As an initial matter, the lack of accepted standards for approval of MRV plans creates uncertainty. Further, operational changes—such as the drilling of a new injection well—may require the EPA's approval of a revised MRV. EOR is an adaptive process that frequently involves well reconfigurations that could require MRV revisions. Finally, reporting under Subpart RR could be construed as an admission of intent to conduct geologic storage, creating a risk that a well operator could become subject to more onerous permitting requirements under Class VI of the UIC program. *See* 40 C.F.R. § 144.19(a).

Second, the injection of captured CO_2 from a coal-fired EGU could subject an EOR well to regulation under the Resource Conservation and Recovery Act ("RCRA"). In a recent rulemaking, the EPA determined that a CO_2 stream injected into a UIC Class VI well is a "solid waste" under RCRA and conditionally exempted captured CO_2 streams that are injected into Class VI wells. 79 Fed. Reg. 350 (Jan. 3, 2014). In contrast, the EPA stated "CO_2 … used for its intended purpose as it is injected into a UIC Class II well for the purpose of [EOR] … would not generally be a waste management activity." *Id.* at 355. However, the EOR "safe harbor" provision does not appear to include "CO_2 streams," the term of art the EPA uses to define captured, anthropogenic CO_2. Thus, an EOR operator that uses captured CO_2 from a coal-fired EGU may risk losing the RCRA safe harbor otherwise available to EOR activities. In the absence of the EOR safe harbor, a well operator who is unsuccessful in convincing the EPA that its EOR operations are not "waste management activities" would become subject to RCRA regulations for solid waste disposal, including additional permitting obligations, potential regulation as a RCRA hazardous waste (depending on testing results) and potential RCRA liability through government enforcement actions or citizen's suits. Further, to the extent that EOR activities using captured, anthropogenic CO_2 are considered a form of waste management, any incidental leakage of CO_2 from the reservoir could result in potential RCRA liability and enforcement actions.

Third, in the EPA's draft guidance on transitioning from UIC Class II to Class VI permits ("*Class II to Class VI Guidance*"), the EPA asserts that it can unilaterally require a Class II operator to obtain a Class VI permit if it determines that the well's primary purpose changes from EOR to geologic storage. Among the factors the EPA may consider in making that determination is the "source and properties of the injected carbon dioxide." 40 C.F.R.

§ 144.19(b)(8). A shift from Class II to Class VI will not only result in more onerous permit obligations, but could also raise legal issues for well operators whose contracts do not explicitly permit injection for the purpose of long-term storage.

b. There Is No Basis in the Record to Conclude That Non-EOR CO_2 Storage Will Be Available.

In addition to its unfounded assumptions regarding availability of EOR markets, the EPA asserts without justification that non-EOR geologic storage is a viable option for coal-fired EGUs. *See* 79 Fed. Reg. at 1,472. As an initial matter, the EPA's claim that geologic storage "is technically feasible and available," *id.*, lacks record support. The EPA fails to include any discussion of commercial geologic storage facilities, and merely references in passing the existence of four foreign sequestration projects. *See id.* n.201. The EPA provides no data or analysis regarding these facilities and fails to acknowledge that at least one has been suspended due to concerns over vertical leakage. [38] In the absence of some detail regarding operations and reliability, these facilities do not support the EPA's conclusion. Further, the EPA acknowledges "the need to continue to advance the understanding of various aspects of the technology, including, but not limited to, site selection and characterization, CO_2 plume tracking, and monitoring." *Id.* The uncertain and emerging nature of geologic storage is confirmed by recent government studies seeking to better understand options for long-term geologic storage. *See, e.g.*, NETL, United States 2012 Carbon Utilization and Storage Atlas (4th ed.) ("Carbon Atlas") at 11, 16; NETL/DOE Roadmap at 15. It is arbitrary and capricious to assert that such an emerging technology is "technically feasible and available" in the absence of any evidence of successful commercial implementation.

The EPA also lacks record support for its assertion that geologic storage capacity "is widespread and available throughout the U.S. and Canada," and typically available within 50 miles of existing power plant locations. 79 Fed. Reg. at 1,472-73. However, it is arbitrary and capricious for the EPA to simply rely on the potential availability of suitable formations, such as those included in the Carbon Atlas and U.S. Geologic Survey review. *See* 79 Fed. Reg. at 1,473. As the EPA acknowledges, such reviews of potentially suitable formations cannot establish actual availability because "each potential geologic sequestration site must undergo appropriate site characterization to ensure that the site can safely and securely store CO_2." 79 Fed. Reg. at 1,473. In fact, site-specific availability may be difficult to establish. For example, the IEPA's analysis of geologic storage for the Taylorville Energy Center demonstrates that extensive feasibility and cost studies are required to determine whether a potential site is actually suitable for long-term carbon storage.[39] This is further underscored by the detailed permitting requirements included in the EPA's UIC Class VI regulations. *See* 40 C.F.R. § 146.82-84. In addition, many theoretically available reservoirs are shale formations that may be used for oil and gas development,[40] and it not clear whether geologic storage is compatible with oil and gas

[38] *See* MIT, Carbon Capture & Sequestration Technologies: In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project, *available at* https://sequestration.mit.edu/tools/projects/in_salah.html (last visited April 2, 2014).

[39] IEPA, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application for the Taylorville Energy Center in Taylorville, Illinois at 116-123.

[40] T.R. Elliot and M.A. Celia, Potential Restrictions for CO_2 Sequestration Sites Due to Shale and Tight Gas Production, *Environ. Sci. Technol.*, 2012, 46(7), pp. 4223-4227.

development practices such as hydraulic fracturing, which are essential to the development of domestic natural gas reserves.

c. The EPA Ignores Legal and Logistical Uncertainty Related to Geologic Storage.

The EPA's claims regarding the availability of geologic storage are also arbitrary and capricious because they ignore significant legal and logistical barriers to geologic storage. The EPA's conclusion that "there are no insurmountable technological, legal, institutional, regulatory, or other barriers" to CCS, 78 Fed. Reg. at 1,471, is focused solely on federal regulations under the UIC program, GHG Reporting Rule, and RCRA. In contrast, the EPA's GHG Guidance took a broader view, and identified legal and logistical barriers including "obtaining contacts for offsite land acquisition (including the availability of the land), the need for funding (including for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage." GHG Guidance at 36. These concerns have been borne out in practice. For example, the EPA rejected CCS as BACT for the Palmdale Hybrid Power Plant in part because "[i]t is not clear that the applicant could obtain the necessary" rights of way, which are "usually limited to 'public utilities.'"[41] IEPA reached a similar conclusion in evaluating CCS for the Taylorville Energy Center:

> [C]onsiderable uncertainty exists with respect to a number of requisite conditions for CCS here, including access to an existing pipeline and a suitable geologic reservoir over the life of the plant, sequestration field land and subsurface rights acquisition, development of a site for secure long-term storage, proven geology favorable for long-term storage, and other uncertainties about the long-term ability of the Mt. Simon formation to sequester CO_2 …[42]

Many aspects of geologic storage will ultimately be subject to state law, providing additional sources of uncertainty and unpredictability due to a lack of established law and differences between jurisdictions. For example, carbon dioxide pipelines are subject to state law, and, because of this, negotiating rights of way for CO_2 pipelines will be a complicated and expensive process, particularly if a state determines that CO_2 pipeline operators are not entitled to employ eminent domain to acquire rights of way. Rights of way over federal lands would be further complicated by NEPA. And storage of carbon is no more certain, as questions regarding ownership of underground pore space, long-term liability, and insurance remain unresolved. *See* Task Force Report at 67-75. Storage on federal land will raise additional questions regarding rent and reporting obligations under Subpart RR. While these critical issues are largely outside of the EPA's jurisdiction and control, it is nevertheless arbitrary and capricious for the EPA to simply ignore them when assessing whether geologic storage is currently available.

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[41] EPA, Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Plant (Oct. 2011) at 37.

[42] IEPA, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application for the Taylorville Energy Center in Taylorville, Illinois at 114.

d. It Is Unlawful for the EPA to Prohibit Coal-Fired EGUs in Areas That Lack Geologic Storage Options.

The EPA acknowledges in the proposed rule that requiring geologic storage of captured CO_2 will act as a *de facto* prohibition on new coal-fired EGUs in certain parts of the country. *See* 79 Fed. Reg. at 1,466-67. The EPA cannot justify this unlawful *de facto* ban by pointing to the legislative history of the NSPS program.

First, the need for uniform national standards does not apply to GHGs. Nationally applicable NSPS were intended "to prevent pollution havens—caused by some states seeking competitive advantage by limiting their pollution control requirements—and to assure that areas that had good air quality would be able to maintain good air quality even after new industrial sources located there…." *Id.* at 1,466. However, GHGs are global pollutants and do not pose localized threats like criteria pollutants. In fact, applying a national standard based on CCS would have the effect of creating the exact type of localized competitive advantages that Congress sought to avoid when it enacted the NSPS program, as only regions with geologic storage could construct coal-fired EGUs. Second, the fact that industrial facilities can be prohibited from being constructed in certain areas under Section 110's attainment provisions is irrelevant here. In addition to the fact that GHGs do not produce localized air impacts, there are no national ambient air quality standards for GHGs that could be used to invoke Section 110. Thus, the legislative history of the Clean Air Act does not support the EPA's decision.

Likewise, the EPA's reliance on case law is unavailing. The EPA relies on the "basic demand" theory, under which it claims it can ban new coal-fired EGUs under Section 111 as long as basic demand for electricity can be met through other sources. 79 Fed. Reg. at 1,481. *Int'l Harvester Co. v. EPA*, 478 F.2d 615 (D.C. Cir. 1973) does not support the EPA's position. In *Int'l Harvester*, the court affirmed the EPA's decision not to extend the deadline for Title II emissions standards after concluding that petitioners failed to demonstrate that the necessary control technology was not available. *Id.* at 624-26. Here, in contrast, the EPA proposes a rule that requires a technology—geologic storage—that is not, and never will be, available in some parts of the country. Further, in *Int'l Harvester*, the requirement to apply the "basic demand" theory was mandated by the statute, *id.* at 640; no such statutory mandate applies under Section 111.

The EPA's reliance on *NRDC v. EPA*, 489 F3d 1364 (D.C. Cir. 2007) is equally unavailing. *NRDC* involved a claim under Section 112 that certain control technology, while technically available, was too expensive. *Id.* at 1375-76. In addition to the fact that the Section 112, maximum achievable control technology ("MACT") is much more stringent that the Section 111 BSER standard, geologic storage faces significant technological, geological, and legal challenges, not merely economic challenges associated with implementing a control technology. In sum, the EPA fails to provide any relevant and applicable support for its assertion that it can impose a nationally applicable standard that simply cannot be met by certain portions of the country.

6. The EPA Overstates the Technology-Forcing Nature of the NSPS Provisions.

The EPA's selection of CCS as BSER is unduly reliant on the technology-forcing nature of Section 111. The EPA asserts that it must "consider[] whether the system promotes the implementation and further development of technology." 79 Fed. Reg. at 1,434. Nothing in Section 111 or the EPA's implementing regulations mandates such an approach. Instead, the EPA relies on *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), a case decided under far different facts. In *Sierra Club*, the EPA set an emission limit for sulfur dioxide that would accommodate development of dry scrubbing technology, *id.* at 340-41, but the court upheld the standard because it was also achievable by commonly used control technologies including wet scrubbing and coal washing, *id.* at 348, 356. Here, in contrast, there are no other alternatives to CCS—let alone commonly used alternatives—that can meet the proposed emissions limits. In fact, the EPA refused to even consider alternatives that are technically feasible today based on the conclusion that "they do not provide meaningful reductions in CO_2 emissions from new sources." 79 Fed. Reg. at 1,435. The EPA's rejection of energy efficiency technologies because they fail to promote "CO_2 pollution-reduction technology from power plants," *id.* at 1,435, is particularly problematic as the EPA has previously concluded in the BACT guidance that these technologies are themselves pollution-reduction technologies. GHG Guidance at 21.

Instead, what becomes clear in the proposed rule is that the alternative control technologies are dismissed by the EPA because they do not promote the development of CCS. 79 Fed. Reg. at 1,435. This approach is arbitrary, capricious, and unlawful for several reasons.

First, the EPA's approach is circular; no pollution-reduction technology other than CCS can promote the development of CCS. Second, Section 111 does not authorize the EPA to mandate the use of a control technology such as CCS in order to develop that technology. The EPA acknowledges that CCS is, at best, nearing the demonstration stage. CCS is not adequately demonstrated now, and the EPA cannot use the NSPS regulations to force such an outcome. Third, the Clean Air Act prohibits the EPA from using the NSPS program to mandate the development and deployment of a single technology such as CCS. *See* CAA § 111(b)(5) ("Nothing in this section shall be construed to …authorize the Administrator to require[] any new or modified source to install and operate any particular technological system of continuous emission reduction ….").

Further, the EPA's intent to use the standard of performance to develop CCS is likely to backfire. As described above, CCS is an emerging technology that will require significant continued development along several technological and legal fronts. However, because the proposed standard will result in a de facto ban on new coal-fired EGUs, it will have the effect of stalling rather than promoting the development of CCS technology.

7. The Record Does Not Support the EPA's Finding That the Costs of CCS are Reasonable.

a. CCS Cannot Be "Accommodated by the Industry."

The administrative record clearly refutes the EPA's claim that the costs of CCS "can be accommodated by the industry." 79 Fed. Reg. at 1,475. To date, government grants, loan guarantees, and subsidies play a significant role in the financing for every CCS project cited in the rule. The EPA argues that it can ignore the role that these subsidies play in assessing whether CCS costs are reasonable because all types of electricity generation receive some type of subsidy. *Id.* at 1,478. This is arbitrary and capricious. First, the EPA's own standard for reasonableness—whether costs "can be accommodated by the industry"—includes no provision for including costs that are accommodated by governments rather than industry.

Second, the Clean Air Act does not permit the EPA to offset costs by relying on general subsidies available to an industry. Under Section 111, the EPA must "tak[e] into account the costs of achieving such reduction" (*i.e.* the standard of performance), not the net costs (after accounting for subsidies) of constructing and operating the stationary source. *See* 42 CAA § 111(a)(1). Thus subsidies, such as the Price-Anderson Act subsidies, domestic oil and gas subsidies, coal development subsidies, and renewable subsidies cited by the EPA, are irrelevant because they have nothing to do with constructing and operating pollution-reduction technology.

Third, accounting for subsidies in cost calculations is inconsistent with the EPA's past practice of excluding such subsidies. In previous assessments of CCS, the EPA has unfailingly taken the position that the future application of CCS subsidies is speculative and should not be considered when assessing the economic viability of CCS. For example, the EPA recently declined to consider Section Q45 tax credits for carbon sequestration when rejecting CCS in a PSD BACT analysis because "the long-term uncertainty, speculativeness, and over-complexity of these considerations would make it advisable to exclude them from consideration in the BACT analysis."[43] In other permitting decisions, the EPA has refused to assume, in the absence of a confirmed government commitment, that government grants or cost-sharing arrangements would be obtained for CCS projects.[44] This is also consistent with the EPA's position in the NSR Manual, which states that income tax considerations should not be considered a part of economic costs.[45] The EPA cannot reverse this policy judgment without providing a reasoned basis for doing so. *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 57.

In the absence of any evidence that a CCS unit has been constructed without government assistance, there is no factual basis to show that CCS actually "can be accommodated by the industry." This position is further supported by the role that costs have played in the rejection of CCS in BACT analysis and the failure of CCS projects because of economic reasons. *See supra* Section III.C.1.a, b.

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[43] EPA, Response to Public Comments, ExxonMobil Chemical Company Baytown Olefins Plant at 11.

[44] EPA, Response to Public Comments, Celanese Clean Lake Plant at 5, 23.

[45] Draft, New Source Review Workshop Manual (Oct. 1990) at App'x B.11.

b. It Is Arbitrary, Capricious, and Unlawful for the EPA to Rely on a Levelized Cost of Electricity to Justify CCS.

The EPA's attempt to justify the proposed standard by comparing the levelized cost of electricity from new coal-fired power plants with and without CCS is arbitrary, capricious, and unlawful. Because of the serious defects in the EPA's levelized cost analysis, the Agency has no basis for using the analysis to justify the proposed rule.

First, the EPA's assertions regarding the additional costs of "partial" CCS are contradicted by the very sources on which the EPA relies. The EPA asserts in the proposed rule that partial CCS will increase the costs of a pulverized coal boiler by approximately 20% (from $92/MWh to $110 MWh). 79 Fed. Reg. at 1476, Tbl. 6. However, the NETL studies from which the EPA claims the levelized cost estimates were derived do not support that conclusion. In a 2011 study cited by EPA, NETL estimates that a 850% "partial" capture scenario (reducing CO_2 emissions to 1,055 CO_2/MWh) would increase costs by 43.3%.[46] The other two NETL studies contain no reference to partial CCS or its costs. Thus, the only evidence from NETL suggests that the costs of partial CCS would be more than twice as high as the EPA's estimate of $18/MWh. In the absence of any supporting evidence to contradict the NETL study, the EPA's cost estimate for partial CCS is arbitrary and capricious.

Second, the EPA lacks any real-world data on which to base its cost estimates. As the Associations have explained, there are no commercial-scale coal-fired EGUs employing CCS anywhere in the world. As a result, the EPA has no factual basis for projecting levelized cost of electricity estimates. Further, it would be arbitrary and capricious to rely on estimates generated from facilities currently under construction because of the well-documented cost overruns occurring at virtually all of those facilities. Finally, the EPA's decision to propose "partial" CCS creates even more cost-estimate challenges, as the facilities under construction intend to capture higher proportions of CO2. The EPA offers no basis for projecting the costs of partial CCS from cost estimates for full CSS. Thus, from a factual standpoint, there is simply no basis for the EPA's conclusion that CCS will add $18/MWh to the cost of a coal-fired EGU. *See* 79 Fed. Reg. at 1478.

Third, the EPA exacerbated its cost-estimate problems by relying on a series of faulty assumptions to reduce the cost of partial CCS by an additional 38%. The EPA begins its analysis with an unsupported conclusion that the costs of CCS will be $29/MWh. RIA at 5-51. EPA then deducts a portion of that cost based on the assumption that EGUs employing CCS technology will sell their captured CO_2 for EOR. As the Associations explained, *supra* Section III.C.5, this is factually incorrect and inconsistent with the EPA's position in PSD BACT determinations[47] and the GHG Guidance[48] that a facility could not count on the availability of EOR when assessing the feasibility of CCS technology. The EPA offers no rational basis for reversing the Agency's

[46] Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, DOE/NETL, 2011.1498, Exh. 5-11 (May 2011).

[47] EPA Region 6, Response to Public Comments, ExxonMobil Chemical Company, Baytown Olefins Plant, Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, PSD-TX-102982-GHG (Nov. 25, 2013) at 11; *see also* EPA, Response to Public Comments, Celanese Clean Lake Plant at 23.

[48] GHG Guidance at H-2.

prior position that there is no guarantee at the time of planning or even construction that EOR will be available to offset a portion of the costs of CCS technology. The EPA then reduces the estimated costs of partial CCS further by employing a 5% deduction based on the social cost of carbon ("SCC"). As the Associations explained in prior comments, the SCC analysis is subject to numerous flaws[49] and, as a result, should not be utilized in projecting the levelized cost of electricity. Finally, the EPA reduces costs by an additional 3% based on the assumption that partial CCS will reduce emissions of other pollutants. However, the 2011 NETL study showed that emissions of nitrogen oxide, particulate matter, and mercury will increase on a pound per megawatt hour basis if CCS is installed.[50] Likewise, in the PSD permit decisions, the EPA has concluded that CCS will increase emissions of conventional pollutants.[51] For these reasons, it is arbitrary, capricious, and inconsistent with the administrative record for the EPA to rely on EOR-related cost reductions when comparing the levelized costs of electricity.

Fourth, the EPA seeks to reduce the levelized costs of electricity for partial CCS by using projected "Nth-of-a-kind" or "NOAK" costs when there is currently no "first-of-a-kind" ("FOAK") example of a commercial-scale coal-fired EGU applying any form of CCS. *See* 79 Fed. Reg. at 1476, Tbl. 6. The EPA attempts to justify the lower NOAK costs because of "the 'learning by doing' and risk reduction benefits that result from serial deployment as well as from continuing research, development and demonstration." *Id.* But, in the absence of an established technology, it is arbitrary and capricious for the EPA to ignore "the unique cost premiums associated with FOAK plants that must demonstrate emerging technologies and iteratively improve upon initial plant designs." *Id.* Thus, rather than estimating the costs that could be incurred by a facility seeking to install CCS as of January 8, 2014—the day the NSPS became effective upon publication of the proposal—the EPA is relying on projected costs at some undisclosed future time when the Agency believes that CCS will be an established, mature technology. *See Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-392 (D.C. Cir. 1973) ("Since the standards here put into effect will control new plants immediately, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed."). It is arbitrary, capricious, and unlawful for the EPA to rely on such long-term cost projections when the Agency will have an opportunity to reconsider those costs at the next statutory review period.

Fifth, the EPA offers no rational basis for reversing its prior conclusions in the GHG Guidance and in comments on PSD permitting decisions that CCS is prohibitively expensive. *See, e.g.*, GHG Guidance at 42 ("At present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls."). In the absence of a transparent and reasoned analysis that justifies a reversal of the EPA's prior position regarding the costs of CCS, it is arbitrary and

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[49] Comments of American Petroleum Institute, *et al.* on Technical Support Document entitled Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866." Docket No. OMB-OMB-2013-0007-0100 (Feb. 26, 2014).

[50] Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, DOE/NETL, 2011.1498, Exh. 5-11 (May 2011).

[51] EPA Region 6, Response to Public Comments, ExxonMobil Chemical Company, Baytown Olefins Plant, Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, PSD-TX-102982-GHG (Nov. 25, 2013) at 25.

capricious for the EPA to conclude that the levelized costs of electricity for partial CCS are reasonable. *See Jicarilla*, 613 F.3d at 1119.

8. The EPA's Reliance on Subjective, Unverifiable Data Is Arbitrary, Capricious, and Unlawful.

The EPA cannot obtain objective, verifiable data regarding the use of CCS technology because, as explained above, there are no commercial-scale coal-fired EGUs in operation today that employ CCS. Instead, the EPA attempts to rely on the subjective and unverified reports from project developers regarding facilities that in most cases are far from completion. Because these reports are based on the subjective representations of project developers, the public cannot verify their accuracy. For example, it is impossible for the Associations to verify whether the FutureGen2.0 project "is in advanced stages of planning" as the EPA suggests. *See* 79 Fed. Reg. at 1,475. A review of the project simply reveals that it has not yet commenced construction or obtained the permits necessary to do so. Likewise, the Associations have been unable to independently verify the EPA's claims that the SaskPower Boundary Dam project is 75% complete and has already begun performance testing.

It is a violation of Section 307(d) of the Clean Air Act to require the public to sift through news articles, project webpages, and Securities and Exchange Commission filings to verify the EPA's representations in the proposed rule. Further, the history of delays, cancellations, and cost overruns for CCS projects demonstrates that the progress reports and cost estimates provided by project developers are unreliable and often proved incorrect over time. For all of these reasons, it is arbitrary, capricious, and unlawful for the EPA to base the standard of performance on these unreliable and unverifiable sources.

D. The EPA Should Exclude Simple Cycle Turbines in the Final Rule.

Consistent with its initial proposal in 2012, the EPA should exclude simple cycle turbines from the proposed rule. The EPA's inclusion of simple cycle turbines is based on a misconception regarding their role in power generation, will subject them to an uncertain *post hoc* applicability test, and will reduce overall flexibility in electricity generation. However, if the EPA declines to exclude simple cycle turbines, it must create a separate subcategory with separate emissions limits.

1. The EPA Misunderstands and Misstates the Role of Simple Cycle Turbines in Electricity Generation.

It is clear from the proposed rule that the EPA misunderstands the role of simple cycle turbines in electricity generation. Simple cycle turbines lack the efficiency of combined cycle turbines for producing baseload power and cannot compete in that space. Instead, they serve a fundamentally different role in providing peaking power.

The EPA suggests that "combined cycle facilities" must "startup, shutdown, cycle, and operate at part-load more frequently" to compensate for the increased use of intermittent renewable energy. 79 Fed. Reg. at 1,486. This is the role played by simple cycle turbines. Simple cycle turbines have the flexibility to provide gap-filling auxiliary power because they can cold-start quickly, scale through loads, and start and stop several times per day. In contrast, combined cycle turbines are less flexible in operating at partial loads and cannot cold-start quickly in response to changing demand. In fact, at lower loads, combined cycle turbines cannot engage the heat recovery steam generator needed to operate as a combined cycle turbine.

Unlike combined cycle turbines that are designed for baseload power, simple cycle turbines are used to provide peaking power. As a result, they have unpredictable hours of operation and rarely operate at full load. Increasingly, simple cycle turbines are utilized to compensate for highly variable and often intermittent generation from baseload solar and wind facilities caused by fluctuating cloud cover and wind speeds, respectively. The importance of simple cycle turbines will increase as the expansion of intermittent renewable energy sources increases variability in baseload electricity generation. Thus, the EPA's apparent fear that simple cycle turbines will replace combined cycle turbines for baseload power generation is unfounded. *See* 79 Fed. Reg. at 1,459.

2. If the EPA Regulates Simple Cycle Turbines, It Must Create a Separate Subcategory.

If the EPA declines to exclude simple cycle turbines from these regulations, it must create a separate subcategory with a separate emissions limitation that accurately reflects the emissions limits that simple cycle turbines can achieve. First, the EPA underestimates the risk that simple cycle turbines may have to operate more frequently in the future as peaking needs increase. The EPA's historical data showing that less than 1% of simple cycle turbines would trigger the proposed rule's applicability criteria, 79 Fed. Reg. at 1,459, fail to account for the increased reliance on simple cycle turbines that will be caused by the expansion of renewable electricity generation and the retirement of coal and nuclear facilities.[52] Even if NGCC units replace retiring coal and nuclear facilities, there will be increased grid variability until the transition is complete. And variability will remain high in states that are increasing their reliance on renewable energy through renewable portfolio standards. Thus, as the sources used to provide baseload energy continue to change, the EPA must ensure that simple cycle turbines are capable of providing necessary peaking power support, even if usage exceeds the proposed applicability levels.

Second, in any event, there is no rational basis for imposing the same emissions limits on simple cycle and NGCC facilities. Because baseload and peaking power generation are fundamentally different processes, it is arbitrary and capricious for the EPA to lump them together and assert that "virtually all new sources in this category are using NGCC technology." 79 Fed. Reg. at 1,485. The EPA's proposal to establish NGCC as BSER for all stationary combustion turbines fails to account for the fact that simple cycle turbines cannot achieve the same emissions limitations as more efficient NGCC turbines because they operate at lower, less efficient loads and cannot use a heat recovery steam generator. Peaking plants simply cannot use combined cycle technology to limit emissions and, thus, should not be subject to the stringent emissions limits applicable to baseload NGCC generation. For the same reason, the EPA should not base the standard for simple cycle turbines on the EIA Advanced Energy Outlook 2013 Report that allegedly finds that "advanced simple cycle combustion turbines have *a baseload rating* CO_2 emission rate of 1,150 lbs CO_2/MWh…." *Id.* (emphasis added). Because simple cycle

[52] *See* EIA, Annual Energy Outlook 2014, Early Release Overview at 2-3, 8, 11, 14-15, *available at*, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf.

turbines do not provide baseload power, even the most efficient turbines will be unable to meet the 1,150 lbs CO_2/MWh limit that the EPA suggests is achievable. Simple cycle turbines, however, are not used for baseload generation, providing further evidence that the EPA fails to understand the difference between the two types of turbines.[53] Due to these differences, a separate, achievable emissions limit must be applied to simple cycle turbines.

Third, applicability of the standard of performance must be based solely on a source's intended purpose at the time of construction. The EPA proposes an applicability threshold based on actual emissions data over a three-year period. While this may be appropriate for baseload power plants that are intended to operate at or near capacity at all time, it creates significant uncertainty for facilities utilized for peaking power and whose hours of operation can fluctuate wildly. Regardless of the intent of the owners and operators at the time of construction, such facilities could trigger the applicability criteria and become subject to the standard of performance more than three years after construction is complete. If the proposed rule is finalized, and simple cycle plants are subject to the NSPS emission limitations based on the current utilization provisions, owners and operators could face an impossible position. In the event that hours of operation increase, facilities may have to choose between shutting down and risking grid reliability and contractual and regulatory liability, or continuing to operate and risk being subject to three years or more of NSPS violations. Instead of the proposed *post hoc* standard, the EPA should base applicability on a source's intended purpose and expected operating criteria at the time of construction. This will give owners and operators the certainty needed to allow investments in simple cycle turbines as necessary to provide peaking power.

E. The EPA Should Exclude Industrial Combined Heat and Power Units from the NSPS.

Combined heat and power ("CHP") offers significant environmental benefits. As the EPA has noted elsewhere, CHP systems capture and utilize "heat that would otherwise be wasted from the production of electricity," meaning that they "require less fuel than equivalent separate heat and power systems to produce the same amount of electricity."[54] CHP units promote grid reliability through distributed generation and can reduce CO_2 emissions significantly in comparison to independent steam generation with conventional boilers and electricity generation by conventional EGUs. In recognition of these benefits, the U.S. Department of Energy has adopted a number of initiatives to promote industrial distributed energy in the United States, and the Administration has set a national goal of increasing CHP deployment by 40 gigawatts (50%) by 2020.

[53] Establishing different regulations for NGCC and simple cycle turbines is also critical for the BACT process. The EPA must make clear in the final rule that the NGCC standard does not constitute the BACT Floor for simple cycle turbines. Failing to do so will effectively ban new simple cycle turbines, as they simply cannot achieve the same emission levels as NGCC facilities.

[54] EPA, Combined Heat and Power Partnership, Environmental Benefits, *available at*, http://www.epa.gov/chp/basic/environmental.html

1. The EPA Should Exempt Industrial CHP Facilities from the Proposed Standards of Performance.

In light of these environmental benefits and the Administration's clear support for industrial efficiency, the EPA should exempt entirely industrial CHP units that produce both useful thermal and electrical energy at the point of use and whose primary purpose is to deliver a continuous supply of thermal energy to its host. First, such an exemption will promote adoption of efficient, reliable, and low-emission distributed generation. Second, because industrial CHP units are customized to accommodate source-specific needs, they rarely provide the same balance of thermal energy and electricity production, and these balances may shift over any given time period. As a result, calculation of thermal energy equivalence (conversion to kWh) is extremely challenging for reporting and enforcement purposes. Regulation is further complicated by the use of third party-owned CHP units at adjacent industrial facilities. 79 Fed. Reg. at 1,460. Third, the EPA failed to assess whether industrial CHP units were actually capable of meeting the proposed standards. Rather than providing real-world data, the EPA responded to an OMB inquiry with a hypothetical example of a CHP facility that may not represent real-world conditions.[55] Thus, at a minimum, the EPA should exclude industrial CHP units from Section 111 until it can determine how CHP units could calculate their GHG emissions under real-world conditions and how the proposed emission limitation would impact those units.

2. Alternatively, the EPA Should Provide an Exception for CHP Facilities Whose Primary Purpose Is Not to Produce Electricity for Sale in the Retail Market.

In the event that the EPA decides that an exemption for all CHP units is not warranted, the Associations believe that, at a minimum, the EPA should provide an exception for CHP units whose primary purpose is something other than the production of electricity for sale in the retail market. CHP facilities are used throughout the manufacturing and oil and gas sectors as an efficient means of providing thermal energy and, to a lesser degree, electric energy for internal facility operations. These facilities are typically designed to maximize thermal energy output. In contrast, the supply of electric output to a utility power generation system is limited to residual electric power that cannot be used by the facility. While sale of excess electric output to the grid is an energy-efficient and cost-effective means of addressing excess electric output, the production of such electricity is not the primary purpose of the CHP unit.

Given the fundamental difference between such non-utility facilities and EGUs that are designed specifically for the purpose of supplying electricity to a utility power generation system for the purpose of selling it in the wholesale market, industrial CHP units located at manufacturing or oil and gas facilities should be excluded from the proposed NSPS if the EPA declines to adopt a broader exemption for CHP facilities generally. The EPA should recognize that these facilities are not fossil fired EGUs and exclude them from the subcategories to which the proposed rule applies. To provide greater certainty for facilities, the Associations urge the EPA to adopt a quantitative test that ensures that industrial CHP units used for manufacturing or

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[55] EPA, Summary of Interagency Comments on U.S. Environmental Protection Agency's Notice of Proposed Rulemaking "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (RIN 2060-AQ91), EPA-HQ-OAR-2013-0495-0045 (Aug. 2, 2013) at 5.

oil and gas facilities are excluded from fossil fuel-fired EGU subcategories. The Associations believe that the EPA could employ a variety of methods to exclude from this rulemaking industrial CHP units that are associated with manufacturing or oil and gas facilities whose primary purpose is not to sell electricity in the wholesale market:

- The EPA could exclude any CHP facility that supplies less than two thirds of its net combined thermal and electric output to a utility power generation distribution system or to a utility steam system distribution system on an annual MMBtu basis. Such an applicability standard would ensure that the primary purpose of the CHP unit is to support internal operations at the host facility and not to supply electricity to the grid. Additionally, the EPA could double the capacity and "potential energy output" threshold for CHP units to reflect the fact that CHP units produce thermal energy as well as electricity and the primary purpose is not for sales to a utility power distribution system.

- In recognition of the reduced fuel usage and GHG emissions reduction benefits of CHP facilities in comparison to separate electricity and thermal energy units, the EPA could exclude CHP units that simultaneously produce power and heat and, at the time the unit is placed into service, have an energy savings of 10% or more when compared to units that produce heat and power separately.

- The EPA could provide an exception for manufacturing and oil and gas CHP facilities by using Standard Industrial Classification ("SIC") or other codes to distinguish between the EGUs that are subject to the NSPS and manufacturing and oil and gas facilities that are excluded from it.

- In recognition that industrial CHP units are primarily focused on producing thermal energy, the EPA could exclude CHP units that have total thermal energy production that approaches or exceeds the unit's electricity production.

- The EPA could exclude industrial CHP units by fuel type. For example, the EPA could exempt all industrial CHP unit that are fired predominantly with biomass, are fired with gaseous fuels (i.e., pipeline, natural, field, and refinery fuel bases).

While this is not intended to be an exhaustive list, it provides a number of options, which could be used individually or concurrently, for the EPA to recognize the fundamental difference between commercial EGUs and CHP units operated by the manufacturing and oil and gas industries and provide certainty that the manufacturing and oil and gas industries' CHP units will not be subject to the NSPS for EGUs. Such an approach will promote the EPA's ultimate goal of reducing GHG emissions and encouraging the construction of new energy-efficient CHP units.

3. If the EPA Decides to Regulate CHP Emissions, It Must Do So in a Manner That Accurately Reflects the Unique Nature of This Power Source.

If, despite the comments raised above, the EPA chooses to regulate CHP units, the EPA must make adjustments to the proposed rule to more accurately reflect the real-world operations at CHP facilities. First, the EPA should reconsider its decision to count only 75% of useful thermal output toward gross energy output. *See* 79 Fed. Reg. at 1505. The EPA appears to recognize that this may be incorrect and seeks comment on the appropriateness of crediting "a range of two-thirds to three-fourths" of the useful thermal output in the final rule. 79 Fed. Reg. at 1448. We do not believe that any discount is appropriate. The 75% multiplier disregards the Administration's efforts to promote CHP, ignores some of the benefits of these systems, and is inconsistent with Agency precedent. CHP's chief benefit is its ability to produce *both* thermal and electric output from a single fuel source. By discounting one of these outputs, the proposed rule understates the value and GHG reduction benefits of these systems. Notably, the 2006 NSPS for Stationary Combustion Turbines awarded a full (100%) thermal credit.[56] Several states have similarly awarded a 100% thermal credit.[57] The EPA is aware of this precedent. In fact, the Proposed Stationary Combustion Turbine Rule favorably cited Texas' permit-by-rule regulation, which gives facilities 100% credit for steam generation thermal output.[58] Accordingly, the EPA should credit 100% of the thermal output from CHP units. Second, the Associations agree that a discount for avoided electricity losses through transmission and distribution is warranted. However, as a practical matter, average national transmission and distribution losses are closer to 7%.[59] Thus, if the EPA includes CHP in the final rule, the Associations urge EPA to increase the discount factor from 5% to 7%.

F. The EPA's Proposal to Exclude Modified and Reconstructed Sources Creates Significant Uncertainty for Existing Utilities.

The EPA recognizes the risks and harm that would result from applying the proposed rule to modified and reconstructed sources. However, the EPA's attempt to exempt such sources may fail, resulting in the very harm that the EPA attempts to avoid.

The EPA's proposal to exempt reconstructed and modified EGUs from the proposed standard, 79 Fed. Reg. at 1,446, departs from the text of the CAA and the EPA's NSPS regulations. Section 111(a)(2) defines a "new source" to include modified sources, and the EPA regulations make NSPS applicable to modified and reconstructed sources. *See* 40 C.F.R. §§ 60.1(a), (b), 61.15(a). The EPA offers no defensible explanation of why the Clean Air Act and the EPA's own regulations will not subject modified and reconstructed sources to the proposed

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[56] *See* New Source Performance Standard (NSPS) for Stationary Combustion Turbines (40 CFR Part 60, Subpart KKKK) (crediting 100% of thermal output); New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da) (crediting 75 percent of thermal output from CHP systems).

[57] *See* U.S. EPA, CHP Partnership, Feb. 2013, "Accounting for CHP in Output-Based Regulations," at 7-9 (citing California's multi-pollutant regulations and Texas permit-by-rule and standard permitting program) (http://www.epa.gov/chp/documents/accounting.pdf).

[58] 70 Fed. Reg. 8314, at 8318 (Feb. 18, 2005).

[59] U.S. Energy Information Administration, Frequently Asked Questions: How much electricity is lost in transmission and distribution in the United States? (reporting "about 7%") (http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3); *see also* U.S. Energy Information Administration, DOE/EIA-0348(01)/2, Jan 27, 2012, State Electricity Profiles 2012 (Table 10: "Supply and Disposition of Electricity, 2000 and 2004 through 2010 (Million Kilowatthours)") (http://205.254.135.7/electricity/state/pdf/sep2010.pdf; Table 10) (line losses calculated as ["estimated losses" divided by "total disposition" minus "direct use"]*100 or [261,990/ (4,170,143-134,554)]*100 = 6.49%)].

standards. Nor does the EPA's apparent intent to issue different regulations for modified and reconstructed sources resolve this issue.[60] Unless and until such alternative standards are issued, there is a risk that modified and reconstructed sources will be required to comply with the proposed standards for new EGUs, resulting in significant harm to existing sources.[61] In addition, even if the proposed standard of performance is not directly applicable to modified and reconstructed sources, PSD permit writers may still apply CCS as BACT if the modification or reconstruction activities trigger PSD applicability thresholds. *See* GHG Guidance at G-1 (NSPS from other source categories may be "a useful starting point" for BACT analyses).

Further, it is not clear that the EPA's proposal as written will actually exempt modified and reconstructed sources. Proposed section 60.46Da states that facilities are subject to the GHG NSPS if construction commences after the date of publication in the Federal Register. But the EPA's definition of "commenced" applies to modified sources. 40 C.F.R. § 60.2. The EPA does not propose to alter this separate definition or otherwise exempt modified and reconstructed sources. Thus, if a legal challenge were to arise, a court might determine that modified and reconstructed sources *are* covered by the GHG NSPS based on the manner by which the EPA has drafted the rule. Thus, if the EPA moves forward with the rulemaking, it must incorporate the exemption directly into subparts Da and KKKK (or, alternatively, TTTT).

As stated above, the Associations believe the EPA should decline to regulate any fossil fuel EGUs under Section 111 at this time. However, if the EPA continues, the proposed exemption for modified and reconstructed sources will add regulatory uncertainty and harm and could invite legal challenges. Until the uncertainty is resolved, EGU owners and operators may not be willing to perform any modifications or reconstructions of their units out of fear that they will be subject to the proposed standard. Thus, to provide adequate notice to interested parties, the EPA should withdraw the proposed rule and proceed, if at all, via ANPR.

G. The EPA's Failure to Complete a Full Cost-Benefit Analysis and Economic Impact Analysis for the Proposed Standard Is Arbitrary, Capricious, and Unlawful.

Through reliance on a series of inappropriate assumptions, the EPA asserts that the cost differential between electricity generation via natural gas and coal will dictate that only natural gas units will be constructed until well after the next NSPS review cycle is complete. In the absence of any new coal-fired EGU capacity, the EPA concludes that the proposal will have no costs or benefits, 79 Fed. Reg. at 1,433; RIA at 5-1, and declines to conduct full cost-benefit and economic impact analyses. The EPA's approach is arbitrary, capricious and unlawful.

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[60] The EPA was directed by the President to issue final standards for modified and reconstructed sources by June 1, 2015. *Presidential Memorandum – Power Sector Carbon Pollution Standards* (June 25, 2013). Further, the EPA submitted a proposed NSPS for GHG emissions from modified and existing sources to the Office of Office of Information and Regulatory Affairs ("OIRA") on April 21, 2014.

[61] As an example, under the proposed rule, there would be considerable uncertainty for a facility considering whether to convert a simple cycle combustion turbine into a combined cycle facility. In particular, it is unclear how the proposed rule would apply to facilities that would also incorporate duct firing as part of the conversion process. Despite its benefits, adding duct firing will have the effect of increasing the short-term CO_2 emissions rate and could trigger NSPS obligations under Section 111(b), despite the many benefits that the inclusion of duct firing would offer.

The EPA's assumption that no new sources will be impacted by the NSPS proposal is incorrect. In a NERA report (attached to these comments), NERA evaluated the likelihood that new coal-fired EGUs would be built under a variety of future development scenarios developed by the U.S. Energy Information Administration ("EIA") for its *Annual Energy Outlook*.[62] Based on these scenarios, NERA concludes that economic conditions in one or more regions in the United States likely would make some number of new coal-fired builds without CCS a preferred economic choice in the near future, over other alternatives, including natural gas builds." NERA at 1. Specifically, under each EIA scenario, NERA found that some coal-fired EGUs would be built in the absence of the proposed rule. Under one scenario, with a planning and construction period of six to eleven years, facilities could decide in the near term whether to add additional coal-fired EGU capacity absent the NSPS' restrictions. And those projects could commence even sooner, depending on other changes to current market conditions. Thus, contrary to the EPA's assertions, new coal-fired EGUs will remain a viable option in the absence of the proposed rule. As a result, the EPA's failure to conduct a complete cost-benefit analysis for the proposed rule is arbitrary, capricious, and unlawful.

Rather than addressing the real-world costs and benefits of requiring coal-fired EGUs to install CCS, the EPA prepared several models which allegedly show that coal-fired EGUs will not be cost-effective. RIA at 5-22 - 34. But the EPA must evaluate the costs and benefits of the emission control technology it has proposed, not the costs and benefits of fuel switching. Rather than assessing the costs and benefits of the CCS programs in the planning or construction phases, the EPA only completes a cursory analysis of the costs and benefits of partial CCS by relying on preexisting RIAs, *id.* at 5-36 - 42,[63] and a NETL cost assumption model, *id.* at 5-50 - 51. But even the EPA's cursory analysis shows that the costs of requiring CCS are likely to exceed the benefits. *Id.* at 5-51.

The EPA's deficient analysis underestimates the likely consequences of the EPA's proposal and violates the Clean Air Act. For example, Section 317 of the Act requires an economic impact analysis for "any new source standard of performance under section [111] of this title." CAA § 317(a)(1). The EPA fails to even mention Section 317 in the proposed rule or RIA. The economic impact analysis must be "as extensive as practicable," *id.*, and the EPA's superficial treatment of economic impacts is insufficient and fails to account for the short- and long-term impacts of the de facto ban on coal. Likewise, under Executive Order 13563, the EPA must "take into account the benefits and costs, both quantitative and qualitative," and "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs …." As explained above, the proposed rule will have a direct effect on the development of new coal-fired EGUs. A proper economic impact analysis that complies with Section 317 of the Clean Air Act

[62] NERA, AEO 2014 Demonstrates a Substantial Probability that New Coal-Fired Generators will be Economical in the Absence of NSPS (May 9, 2014) (Attachment A).

[63] In the RIA, the EPA discusses the social cost of carbon estimates ("SCC Estimates") from an Interagency Working Group's May 2013 Technical Support Document. The Agency uses the SCC Estimates in certain hypothetical examples . RIA at 5-35 – 52. The Associations object to the EPA's use of and reference to the SCC Estimates for all of the reasons outlined in the comments filed by the Associations in response to the Office of Management and Budget's request for comments on the "Technical Support Document entitled Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866." *See* Comments filed by The American Petroleum Institute and others, Docket No. OMB-OMB-2013-0007-0100 (Feb. 26, 2014).

and Executive Order 13563 would undoubtedly rebut the EPA's "no cost" conclusion and demonstrate the arbitrariness of the EPA's analysis.

IV. THE PROPOSED NSPS RULE IS NOT COMPATIBLE WITH THE TAILORING RULE THRESHOLDS.

To the extent that the EPA's Tailoring Rule and interpretations of the Clean Air Act's PSD provisions survive judicial review,[64] the Associations are concerned that finalizing the proposed regulations could undermine the Tailoring Rule's emissions thresholds and trigger PSD permitting requirements for all source of GHGs (or for CO_2 specifically) at much lower statutory levels (the "NSPS trigger issue").[65] Title V permitting requirements may be triggered for the same reason. Therefore, the Associations urge the EPA to avoid unnecessary uncertainty by withdrawing the proposed rule and resolving the NSPS trigger issue before proceeding with any regulation of GHGs under Section 111.

To clarify its intent not to disturb the Tailoring Rule's applicability thresholds, the EPA proposes to include language in the NSPS regulations that explains the EPA's interpretation of the PSD and Title V regulations adopted in the Tailoring Rule. *See* proposed 40 C.F.R. § 60.46Da(j); 79 Fed. Reg. at 1,487. But clarifying the EPA's intent may be insufficient to overcome the plain meaning of the PSD regulations. The NSPS trigger issue stems from the EPA's definition of "regulated NSR pollutant," which includes four distinct categories:

> (i) Any pollutant for which a national ambient air quality standard has been promulgated and any pollutant identified under this paragraph (b)(49)(i) as a constituent or precursor to such pollutant . . . .;
>
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;
>
> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; [and]

[64] The Associations' challenge to Tailoring Rule and interpretations of Clean Air Act's PSD provisions is currently pending before the Supreme Court. *Utility Air Resources Group, et al. v. EPA*, S. Ct. No. 12-1146 and consolidated cases. The Associations do not hereby waive any arguments made in rulemaking comments or legal challenges to the Tailoring Rule and the EPA's related statutory interpretations. *See, e.g.*, Briefing in *Utility Air Resources Group, et al. v. EPA*, S. Ct. No. 12-1146 and consolidated cases; *Coalition for Responsible Regulation, Inc. v. U.S. EPA*, No. 10-1073 and consolidated cases (D.C. Cir.) and in *American Chem. Council v. EPA*, No. 10-1167 and consolidated cases (D.C. Cir.); *see also* National Association of Manufacturers, et al., Petition to Reconsider, Rescind, and/or Revise EPA's Prevention of Significant Deterioration Regulation (July 6, 2010) ("Petition"); American Chemistry Council, Petition to Reconsider, Rescind, and/or Revise EPA's Prevention of Significant Deterioration Regulations: 40 C.F.R. Sections 51.166 and 52.21 (July 6, 2010); Comments of Air Permitting Forum, et al., Docket ID No. EPA-HQ-OAR-2009-0517-5181 (Dec. 28, 2009) (Tailoring Rule); Comments of American Chemistry Council, Docket ID No. EPA-HQ-OAR-2009-0517-5181 (Dec. 28, 2009) (Tailoring Rule); Comments on EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability, Limitations and GHG Synthetic Minor Limitations (April 20, 2012).

[65] The Associations refer to this phenomenon as the "NSPS trigger issue."

> (iv) Any pollutant that otherwise is subject to regulation under the Act as defined in paragraph (b)(48) of this section.

40 C.F.R. § 51.166(b)(49). The EPA then defines "major stationary source" as a source that emits, or has the potential to emit, 100 or 250 tons per year of a regulated NSR pollutant (depending on the type of source). *Id.* § 51.166(b)(1)(i). The Tailoring Rule adjusted the statutory thresholds for GHG emissions by modifying the definition of "subject to regulation" in the fourth category. *See, e.g., id.* § 51.166(b)(48). But this adjustment to the emissions thresholds did not alter the separate triggering effect of Section 111. *See id.* § 51.166(b)(49)(ii).[66] The NSPS trigger issue is also complicated by the fact that the Tailoring Rule applicability thresholds apply to the pollutant GHGs, *see id.* (b)(48)(i), while the EPA proposes to regulate a different pollutant, carbon dioxide, in the NSPS, *see, e.g.*, proposed 40 C.F.R. § 60.40Da ("Standards for carbon dioxide (CO_2)").[67]

The EPA's proposal to include an interpretive gloss on the Tailoring Rule in the NSPS regulations may be insufficient to solve the problem because an agency's interpretation of its regulations is only entitled to deference if "the language of the regulation is ambiguous." *Christensen v. Harris County*, 529 U.S. 576, 588 (2000). It will be difficult for the EPA to argue that the Tailoring Rule's adjustment of the PSD applicability thresholds is ambiguous because the Agency has already acknowledged that "[t]he Tailoring Rule, *on the face of its regulatory provisions*, incorporated the revised thresholds it promulgated into only the fourth prong . . . and not the NSPS trigger in the second prong." 79 Fed. Reg. at 1,488 (emphasis added). Thus, despite the EPA's assertions to the contrary, the PSD regulations appear clear on their face.

The EPA's proposed corrective provisions, *see* proposed 40 C.F.R. §§ 60.46Da(j), 60.5515(b), may also be insufficient because they are located in the NSPS regulations, not the PSD regulations themselves. It would be simpler, and more likely to survive judicial scrutiny, if the EPA were to modify the PSD and Title V regulations, for example, by adding "other than GHGs" after "any pollutant" in 40 C.F.R. § 52.21(b)(50)(ii).[68] In addition to clarifying the scope of the NSPS trigger, this approach would obviate the need to add corrective language in each successive NSPS that imposes standards of performance for GHGs.

Further, the EPA fails to address how the NSPS trigger issue may apply under the EPA - approved PSD programs administered by states and other jurisdictions. While the EPA's proposed fix may apply in PSD-delegated states such as Illinois, its interpretive gloss may not literally apply to state and local provisions with different regulatory text. The EPA must address the fact that these jurisdictions may need to take additional steps to correct the NSPS trigger issue. At a minimum, states that mirrored the EPA's approach in their own state regulations will require a similar interpretive fix as what the EPA has proposed here. But for states that followed a statutorily-required rulemaking process, the process is more challenging, as the state would need to follow its own rulemaking procedures to adopt the EPA's proposed corrections and then

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[66] As explained below, the precise nature of the problem may vary in states and other jurisdictions with EPA-approved PSD programs, but this merely complicates any potential solution offered by the EPA.

[67] In contrast, the proposed regulations for NGCC EGUs clearly state that the pollutants regulated under that subpart include GHGs. *See* proposed 60.4315(a).

[68] Similar changes would be needed for part 166.

obtain the EPA's approval of a state implementation plan ("SIP") revision. This process can be time consuming, and the NSPS trigger issue may apply until the state adopts regulations and obtains the EPA's approval of a revised SIP.

The EPA's suggestion that it can "propose a rule that is comparable to the SIP PSD Narrowing Rule" for any state that informs the EPA that it must revise its SIP, 79 Fed. Reg. at 1,488, is also unlikely to succeed. The PSD Narrowing Rule[69] does not address the NSPS trigger issue and would, thus, be an ineffective option for ensuring that state regulations applying PSD requirements below Tailoring Rule thresholds are not federally enforceable. And, in any event, such an approach would not resolve state law compliance issues. For example, although Colorado is subject to the PSD Narrowing Rule, the rule does not limit the scope of Colorado's *state law* (and associated state enforcement provisions), which apparently will require GHG permitting at 100/250 tpy thresholds if GHGs are regulated under Section 111. Like the Associations, states are concerned that they may not have sufficient time to amend their rules to address the NSPS trigger issue.[70]

For all of these reasons, it is imperative that the EPA resolve the NSPS trigger issue before regulating GHGs under Section 111.[71] While the Associations do not believe that the EPA should proceed with the NSPS GHG rule, if the EPA chooses to do so it must first address the root cause of the NSPS trigger issue in the PSD and Title V regulations and the uncertainty posed by state regulations. To do so, the EPA must first issue an ANPR so it can collect the necessary information from jurisdictions with EPA-approved PSD programs to ensure that the Tailoring Rule thresholds will remain in place if GHGs are regulated under Section 111. Given the costs that the NSPS trigger issue could impose, the EPA must proceed cautiously and remove all uncertainty before issuing any final regulations.

V. ADDITIONAL COMMENTS ON THE EPA'S PROPOSED RULE IF EPA PROCEEDS WITH THIS RULEMAKING.

A. If the EPA Proceeds with This Rulemaking, It Must Include a Multi-Year Compliance Option.

If the EPA proceeds to issue final standards of performance for coal-fired EGUs, the Associations support the EPA's proposals to build flexibility into the standards. As an initial matter, the Associations believe that a 12-month compliance period is necessary to account for the predictable variations in EGU efficiency and emissions rates over the course of each year. *See* 79 Fed. Reg. at 1,481. A shorter compliance period would effectively reduce the emissions limitations by requiring facilities to ensure that they can achieve compliance even during the least efficient operating periods. However, the Associations do not support the EPA's proposal for a rolling compliance period with compliance determinations required each month, *id.* at 1502-03,

[69] Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans, 75 Fed. Reg. 82,536 (Dec. 30, 2010).

[70] Letter and Comments from William C. Allison, V, Director, Air Pollution Division, Colorado Department of Public Health and Environment to U.S. EPA, Docket No. EPA-HQ-OAR-2009-0517-19277, at 4-5 (Apr. 20, 2012).

[71] The Associations agree with the EPA that PSD and Title V requirements cannot be triggered until the EPA issues final regulations.

as a calendar-year-based compliance period will reduce the burden on regulated entities while providing sufficient emissions information to the facility and to the EPA.

The Associations also support an alternative 84-month compliance period. *Id.* at 1,482. Such an approach adds additional flexibility by allowing facilities to compensate for unexpected, short-term challenges. However, there is no reason for the EPA to require a lower emissions limit for this compliance period. Facilities should not be punished for using long-term emissions reductions to compensate for short-term emissions excursions. Thus, the Associations support an emissions limit that is the same as—or as close as possible to—the limit for the 12-month compliance period.

B. The Associations Support the EPA's BSER Analysis for NGCC Turbines.

The Associations support the EPA's proposed standard of performance for NGCC turbines, which is appropriately based on technology that is currently used in commercial NGCC operations and accounts for critical factors such as cost, emissions profile, and potential adverse effects on the structure of the electric power sector. 79 Fed. Reg. at 1,485; *see also id.* at 1,486 (90% of facilities constructed in past 5 years can meet the proposed standard). The Associations also support the EPA's decision to consider real-world emissions data and to propose a separate subcategory and standard of performance for NGCC units with heat input rates less than or equal to 850 MMBtu/h. By focusing on actual emissions from commercial-scale facilities, the EPA has ensured that proposed standards are based on adequately demonstrated technology, and has not required adoption of technology that has not been implemented at a commercial scale *See id.* at 1,485 (rejecting CCS after identifying "only one demonstration project" employing CCS technology).

C. The Associations Agree That an Affirmative Defense for Malfunctions Is Warranted.

The Associations agree that an affirmative defense should be available if a malfunction causes a facility to exceed applicable emissions limits. As defined in the proposed rule, 79 Fed. Reg. at 1,449, malfunctions are not "reasonably foreseeable" and should not form the basis of liability for the operator who has taken reasonable precautions to prevent the malfunction and responded appropriately. However, to the extent that advanced reporting of malfunctions is required, the Associations believe that the EPA should provide an opportunity for declaratory judgment so that facilities can resolve uncertainty without waiting for a regulator or citizen to bring an enforcement action.

The D.C. Circuit's recent decision in *Natural Resources Defense Council v. EPA*, Case No. 10-1371, D.C. Cir., Slip Op., Apr. 18, 2014, does not change this analysis. That decision occurred just three weeks ago, and at this time the parties have not yet had an opportunity to decide whether to seek further review. Further, the scope of the court's decision is unclear, and the court recognized that affirmative defenses may be appropriate in other contexts. *Id.* at 18, n.2 (citing EPA's approval of an affirmative defense provision in a state implementation plan in *Luminant Generation Co. v. EPA*, 714 F.3d 841 (5th Cir. 2013)). Thus, the Associations do not believe that the EPA is bound by any judicial precedent that would prohibit it from including in a final rule an affirmative defense for malfunctions.

D. The EPA's Subpart TTTT Provisions Must Separately Define "Coal" and "Petroleum Coke" Because They Are Different Substances.

Despite being a solid fossil fuel, petroleum coke is fundamentally different from coal because it is produced from oil and can be used in a number of applications besides energy production. The Associations are concerned that the EPA fails to recognize this distinction by including petroleum coke within the definition of "coal" under the proposed Subpart TTTT provisions. *See* proposed 40 C.F.R. § 60.5580 ("Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, *and petroleum coke*. …" (emphasis added)). This differs from the EPA's past practice of distinguishing between coal and petroleum coke. *See* 40 C.F.R. § 60.41 (providing separate definitions for "coal" and "petroleum coke"); *see also* 78 Fed. Reg. 71,904 (distinguishing between "coal" and "petroleum coke" under Subpart Y of the Greenhouse Gas Reporting Program). If the EPA regulates GHG emissions under Subpart TTTT, it should adopt the definitions that currently apply to EGUs under Subpart Da:

> *Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17) and coal refuse. …
>
> …
>
> *Petroleum coke*, also known as "petcoke," means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum coke* is typically derived from oil refinery coker units or other cracking processes.

40 C.F.R. § 60.41.

E. The Proposed NSPS Should Apply to Individual Units, Not to Facilities.

The EPA must clarify inconsistent language in the proposed rule regarding the applicability of the standards of performance. At times, the EPA applies the standards at the facility level. *See* 79 Fed. Reg. at 1,459 ("In today's rulemaking, we propose that standards of performance apply to a facility …."); proposed 40 C.F.R. § 60.46Da(a) ("Your affected facility is subject to this section if construction commenced after [DATE OF PUBLICATION IN THE FEDERAL REGISTER], and the affected facility meets the conditions specified in paragraphs (a)(1) and (a)(2) of this section …."). But the proposed regulations under Subparts KKKK and TTTT would apply only to individual units. *See* Proposed 40 C.F.R. §§ 60.4305(c) ("For purposes of regulation, of greenhouse gases, the applicable provisions of this subpart affect your stationary source turbine if it meets the applicability conditions in paragraphs (c)(1) and (c)(5) …."); 60.5508 ("This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER]."). This difference is critically important to existing facilities that may add new EGU capacity. In light of the EPA's position that these standards should not apply to existing sources, the Associations urge the EPA to clarify—in the preamble and the regulatory text—that applicability criteria are applied on a unit-by-unit basis. Thus, any new capacity would be subject to the proposed standards, while existing units would be regulated, if at all, under Section 111(d). The Associations believe that this approach is preferable to one where such facilities would presumably be regulated as modified sources under Section 111(b).

F. The EPA Must Correct Discrepancies Between Subparts Da and TTTT.

While the proposed alternative subpart TTTT is not intended to differ substantively from the proposed standards under Subpart Da, the Associations have noted several discrepancies between the proposals that would produce materially different regulatory obligations. The EPA must correct these discrepancies and provide an opportunity for public comment on the revised provisions.

For example, as described above, the EPA appears to propose facility-level regulation of coal-fired EGUs under Subpart Da, but unit-level regulation under Subpart TTTT. *See* Proposed 40 C.F.R. §§ 60.46Da(a); 60.5508. Likewise, contrary to the EPA's intent, it appears that the operative language for an affirmative defense for malfunctions was only included in Subpart TTTT. *See* Proposed 40 C.F.R. § 60.5530. There are no changes in subpart Da to incorporate the affirmative defense. *See* 40 C.F.R. § 60.48Da(s). As currently written, that section's affirmative defense provision only applies to 40 C.F.R. §§ 60.42Da (particulate matter), 60.43Da (sulfur dioxides), 60.44Da (nitrogen oxides), and 60.45Da (alternative standards for nitrogen oxides and carbon monoxide). In light of these significant (although apparently unintentional) discrepancies, we urge the EPA to ensure that any final regulations are fully consistent with the EPA's intent as expressed in the preamble.

VI. THE EPA SHOULD NOT EXPAND THE PROPOSED NSPS RULE TO ENCOMPASS EXISTING SOURCES.

Although the proposed rule is limited to new sources, it is abundantly clear that the EPA views this rulemaking as a necessary prerequisite to regulating existing sources under Section 111(d). In the memorandum to the EPA that accompanied the Climate Action Plan, President Obama directed the EPA to propose standards, regulations, or guidelines for existing power plants by June 1, 2014, and to finalize them by June 1, 2015. *See Presidential Memorandum – Power Sector Carbon Pollution Standards*. Likewise, the EPA asserts that "the proposed rule will serve as a necessary predicate for the regulation of existing sources within this source category under CAA Section 111(d)." 79 Fed. Reg. at 1,496. However, regardless of the EPA's actions under Section 111(b), the Agency should not propose to regulate GHG emissions from existing sources now or in the future because it lacks both the legal authority to regulate GHG emissions from existing sources that are already subject to a Clean Air Act Section 112 National Emissions Standard for Hazardous Air Pollutants ("NESHAP") and the policy justification to expand the reach of energy and fuel regulation to existing sources.

A. The Plain Language of Section 111(d) Prohibits the EPA from Establishing NSPS for Source Categories Regulated Under Section 112.

First, as a legal matter, the literal interpretation of the Clean Air Act prohibits the EPA from regulating emissions from a source category under Section 111(d) if that source category is already regulated under Section 112. Section 111(d) provides:

> (1) The Administrator 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* (i) for which air quality criteria have not been issued or *which is not* included on a list published under section 7408(a) or *emitted from a source category which is regulated under 7412* but (ii) to which a standard of performance would apply ….

Section 111(d) (emphasis added). The plain, literal interpretation of Section 111(d) prohibits NSPS for existing sources for any air pollutant emitted from any source category that is regulated under Section 112. In *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527 (2011), the Supreme Court reinforced the plain language of Section 111(d) that focuses on whether a source category is regulated under Section 112. The Court noted an exception to the EPA's authority to regulate existing sources under Section 111: "EPA may not employ § 7411(d) if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§ 7408-7410, or the hazardous air pollutants' program, § 7412. See § 7411(d)(1)." *Id.* at 2537 & n.7. Thus, the EPA cannot regulate any pollutant under Section 111(d)—whether a HAP or non-HAP pollutant—if the source category is regulated under Section 112.

Likewise, the EPA recognized, in the preamble to the proposed Clean Air Mercury Rule, that the plain language of Section 111(d) would prevent the EPA from regulating pollutants from sources regulated under Section 112. In the preamble, the EPA addressed two provisions of the 1990 Clean Air Act Amendments that it alleged were in conflict:

> A literal reading of the House amendment, as contained in the Statutes at Large, is that a standard of performance under CAA cannot be established for any air pollutant that is emitted from a source category regulated under section 112. Under this reading, the EPA could not regulate, under CAA section 111(d), HAP and non-HAP emissions that are emitted from a source category regulated under section 112. A literal reading of the Senate amendment is that a standard of performance under section 111(d) cannot be established for any HAP that is listed in section 112(b)(1), regardless of what categories of sources of that pollutant are regulated under section 112. The House and Senate amendments conflict in that they provide different standards as to the scope of the EPA's authority to regulate under section 111(d).

69 Fed. Reg. 4651, 4685 (Jan. 30, 2004).[72] But, the EPA is entirely incorrect because these two provisions can read consistently with each other if the EPA excludes from Section 111(d) *both* source categories covered by a NESHAP *and* hazardous air pollutants listed in Section 112(d). In contrast, the EPA's proposed interpretation was an attempted compromise that "does not give full effect to the House's language." *Id.* However, the EPA cannot unlawfully dismiss the plain language of Section 111(d).

A core principle of statutory construction is that an agency must adopt a statute's literal, plain meaning.[73] Indeed, this forms the basis of Step One of *Chevron*. *Chevron*, 467 U.S. at 842-43. Here, because Congress' intent is clear and prohibits the EPA from regulating under Section 111(d) any existing source that is also subject to regulation under Section 112, the Clean Air Act amendments do not authorize EPA to ignore the statutory text and adopt any interpretation it sees fit. When, as here, two amendments include different language, they must be harmonized in a manner that gives full effect to both. *Watt v. Alaska*, 451 U.S. 259, 267 (1981). Read together, the House and Senate amendments are complementary, restricting the EPA's authority under Section 111(d) in different ways. The House amendment would prohibit the EPA from regulating any pollutant—whether HAP or non-HAP—from a source regulated under Section 112, while the Senate amendment would prohibit the EPA from regulating any HAP listed in Section 112. Each can be given full effect without harm to the other.

But even if Section 111(d) were considered ambiguous, the EPA's interpretation expressed in the Clean Air Mercury Rule should not be given any weight. First, this outcome is not controlling here because the Clean Air Mercury Rule was vacated in *State of New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). Thus, the EPA's approach in the Clean Air Mercury Rule proposal is void *ab initio*. *See Action on Smoking and Health v. Civil Aeronautics Board*, 713 F.2d 795 (D.C. Cir. 1983).

Second, the EPA's adoption of the interpretation included in the Clean Air Mercury Rule would constitute a reversal of the EPA's past practice under Section 111(d), and the EPA has not provided a "legitimate reason" for doing so. *See Independent Petroleum Association of America v. Babbitt*, 92 F.3d 1248, 1258 (D.C. Cir. 1996). With two exceptions, no Section 112 source categories are subject to regulation under Section 111(d).[74] Given the clear and straightforward meaning of the statute, there is simply no authority for the EPA to change course and regulate these source categories under Section 111(d).

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[72] By way of further background, the EPA also described the unusual history of Section 111(d) in that Federal Register notice. In short, Congress apparently enacted two different amendments to Section 111(d), House and Senate versions, in 1990. The Statutes at Large contain a hybrid section that includes the text of both in alternative parenthetical clauses, but the U.S. Code version only contains the House amendment.

[73] *See, e.g.*, Yule Kim, Congressional Research Service, CRS Report for Congress: Statutory Interpretation: General Principles and Recent Trends 39 (updated Aug. 31, 2008).

[74] For the two exceptions—pulp manufacturing facilities and municipal solid waste landfills—the 111(d) NSPS preceded the Section 112 MACT for that source category. The EPA published Section 111(d) guidelines in March 1979, after it established NSPS for new Kraft Paper Mills. *See* 40 C.F.R. § 60, Subpart BB; the EPA, Kraft Pulping: Control of TRS Emissions from Existing Mills (Mar. 1979). The EPA did not establish a Section 112 NESHAP for this category until 1998. 63 Fed. Reg. 18503 (Apr. 15, 1998). Likewise, the EPA issued the 111(d) NSPS for municipal solid waste landfills in 1999, 64 Fed. Reg. 60,689 (Nov. 8, 1999), more than three years before it established a Section 112 NESHAP for the source category, 66 Fed. Reg. 2,227 (Jan. 16, 2003).

Third, an interpretation that prohibits the EPA from regulating under Section 111(d) existing sources that are also subject to Section 112 NESHAPs is the only "permissible construction of the statute" under Step Two of *Chevron*. *Chevron*, 467 U.S. at 837. As noted above, the House and Senate amendments to Section 111(d) can be fully reconciled by prohibiting the EPA from regulating any emissions from a source category regulated under Section 112 and any HAP emitted from any source. This construction gives full meaning to the House amendment. As a result, any other interpretation that fails to give it full meaning will not withstand judicial scrutiny.

Thus, there is no legal basis for the EPA to avoid the plain, unambiguous language of Section 111(d), which prohibits it from adopting NSPS standards for existing source categories that are already regulated under Section 112. Because the EPA has already regulated the proposed source category, 77 Fed. Reg. at 9,304, it is prohibited from regulating existing EGU sources under Section 111(d).

B. Policy Considerations also Require Adoption of the Plain Language of Section 111(d).

Even if the EPA retains some discretion with respect to interpreting Section 111(d), the Agency is compelled to avoid regulation of GHG emissions from existing sources for policy reasons. Regulating GHGs from existing sources is fundamentally different than regulating GHGs from new sources and from regulating other pollutants from existing sources. The EPA must avoid adding regulatory burdens before it considers the full costs of the regulations, as well as the benefits that might accrue.

First, the regulation of existing sources already subject to Section 112 would add an additional layer of regulatory complexity to industries that can ill afford it. The NSPS program was not intended to provide the EPA with authority over the fuel mix and energy efficiency of existing sources, yet this is likely the only means by which emissions reductions can be realized at existing sources. Further, retrofitting technologies will likely be much more costly than technologies for new sources because initial construction decisions were made without anticipating that the EPA might subsequently regulate them. For example, an existing coal-fired EGU may lack access to natural gas alternatives due to geographical constraints. As a result, Section 111(d) would not provide a cost-effective or efficient means of reducing GHG emissions.

Second, Section 111(d) is a state-driven program, which will create a patchwork of independent and potentially inconsistent rules for existing sources. This system will have significant economic impacts because energy is a fungible commodity that can be marketed across state lines. While new sources may be able to prepare for specific state requirements before they come online, existing sources would be unable to do so, potentially threatening their economic viability and disrupting energy infrastructure, transmission, and reliability. In addition, inconsistent regulatory approaches would create competitive advantages and disadvantages for existing sources, depending on how states choose to implement the NSPS.

Third, by regulating existing fossil fuel EGUs under Section 111(d), the EPA creates a risk of particularly adverse impacts for other trade-exposed sectors. Most of the manufacturing sectors subject to Section 112—including those of the Associations' members—are trade exposed. These facilities operate with very small margins and face stiff competition from nations where there are often no GHG controls. Imposing NSPS GHG regulations for these sources could create perverse effects by encouraging overseas leakage of emissions. Barring NSPS for existing sources would help alleviate some of the burdens of the U.S. regulatory system on trade-exposed industries, reduce the risk of overseas emissions leakage, and help ensure that these sources remain competitive in the global marketplace. In contrast, even the threat of potential future regulation of existing sources will create significant uncertainty. The EPA should clarify now that existing sources subject to Section 112 will not be regulated under Section 111(d).

Fourth, for sources already regulated under Section 112, compliance with NESHAP standards is already onerous and costly, and Congress did not intend that existing sources should be subject to additional regulatory burdens beyond those applied by MACT controls. Subjecting the same source to regulation under both Sections 111(d) and 112 would result in duplicative and burdensome regulations and would be contrary to Congress' intent to regulate existing sources primarily under Sections 108 and 112.

Finally, applying Section 111(d) to the new source category would unreasonably burden state permitting agencies, given the large number of existing sources. Because Section 111(d) is implemented primarily by the states, those agencies would have to address all covered sources within their jurisdiction. But state permitting agencies are already struggling under the administrative burdens of existing federal GHG permitting programs and lack the capacity to implement additional, complex permitting programs such as a Section 111(d) NSPS. *See* 77 Fed. Reg. 14,226, 14,237 (Mar. 8, 2012). As the EPA recognized in the proposed GHG Tailoring Rule Step 3, the Agency should avoid adding to the burdens on state permitting agencies until the agencies develop the capacity to address the existing permitting requirements imposed by federal law.

VII. THE EPA SHOULD NOT EXPAND GHG NSPS TO OTHER SOURCE CATEGORIES.

The EPA has indicated that it is considering GHG new source performance standards for other source categories. For a number of reasons, the Associations believe that even if the EPA were to finalize NSPS for EGUs, it should not proceed with additional GHG standards of performance for other source categories.

As an initial matter, there is no legal obligation to do so. The NSPS Settlement Agreement for Petroleum Refineries ("Refinery Settlement Agreement"),[75] for example, is crystal clear.[76] It does not impose any legal requirements to impose a GHG NSPS for petroleum refineries, Refinery Settlement Agreement at ¶ 9,[77] nor does it "limit or modify the discretion

[75] *Available at* http://www2.epa.gov/sites/production/files/2013-09/documents/refineryghgsettlement.pdf.

[76] The Refinery Settlement Agreement was entered in response to lawsuits by several states and environmental petitioners challenging EPA's 2008 NSPS for petroleum refineries and alleging that the EPA should have included standards of performance for GHG emissions. *Id.* at 1.

[77] While the parties identified dates by which EPA would propose and finalize NSPS for GHG emissions from refineries, *id.* ¶¶ 2, 3, the agreement explained that "the dates stated in Paragraphs 2 and 3 shall be construed to represent only the parties' attempt to compromise claims in litigation, and not to represent agreement that any particular schedule for further agency action is reasonable or otherwise required by law," *id.* ¶ 9.

accorded the EPA," *id.* at ¶ 11. Beyond the lack of legal obligation, the EPA should exercise that discretion to not propose GHG standards of performance for other source categories for all of the reasons set forth below.

There are fundamental and overarching distinctions between EGUs and other source categories in the manufacturing sector that warrant a fundamentally different approach to EGUs and all other sectors. GHG emissions from individual manufacturing source categories are at least an order of magnitude lower than those from EGUs, fundamentally altering the cost-benefit and endangerment equations. If the EPA's rudimentary cost-benefit analysis in this proposal is to be taken at face value, one could conclude that the proposed rule here would have no cost and no benefit. While the Associations disagree with this conclusion, it would clearly not be an appropriate conclusion in other contexts. Other source categories are impacted by a much broader range of factors, such as industry economics, geography, federal and state incentives, transportation networks, ownership structures, foreign competitors, profit margins, and customer bases. All of these must be considered, necessitating a fundamentally different approach than that for EGUs.

Regulating GHG emissions from the manufacturing sector is neither prudent nor necessary. Many industries have already taken aggressive, voluntary action to reduce GHG emissions through energy efficiency initiatives—the only available option to reduce GHG emissions from most manufacturing source categories. Aside from raw materials, energy use is the single largest cost to many manufacturing operations. A commitment to identify and implement cost-effective energy efficiency initiatives has been a primary driver of the continued competitiveness of domestic manufacturing. Unlike with EGUs, the domestic manufacturing sector faces heightened global competition. Thus, manufacturers already understand that reducing expenditures on energy usage in the manufacturing process is of the utmost importance. Given industry's own interest and significant investment in improving energy efficiency, it is unlikely that there are significant cost-effective opportunities that have not already been exploited by manufacturers on a voluntary basis.

Expanding GHG NSPS to other source categories will compound the stifling effect of regulatory overreach on the manufacturing sector. The manufacturing sector will already be impacted from the widespread consequences of such regulations on the EGUs which include less abundant and diverse energy sources, and higher energy costs. New compliance costs associated with GHG NSPS for the manufacturing sector will only compound these impacts. The regulations will have the immediate effect of diverting resources away from long-term investments on improving energy efficiency in order to pay for higher immediate compliance costs and higher energy prices. The ripple effect will extend to the entire value chain, with negative and far reaching economic consequences with little benefit to the environment

New source performance standards are an especially inefficient way to impose GHG emission reductions due to their one-size-fits-all application. Complex manufacturing sectors create products through varied and differing processes. Each source category and, in turn, each facility within a source category, is unique in its design, process, feedstock, and products. In fact, a fundamental justification for the EPA's proposed rule here—to urge the development and deployment of CCS—is even more inappropriate in other contexts than it is for EGUs. Manufacturers have less fuel flexibility in this regard than the power sector. They may not be able to burn certain fuels due to their locations (such as oil-burning island refineries without access to natural gas or with space limitations) or their manufacturing requirements. The application of CCS to any manufacturing facility should be considered on a case-by-case basis, if considered at all.

Global competition also complicates the imposition of uniform standards of performance. Many manufacturing sectors, unlike EGUs, are trade exposed and face stiff competition from overseas competitors. New regulations with significant compliance costs that fail to account for trade exposure will simply result in significant and irreversible job losses without reducing global GHG emissions. To the extent that overseas facilities operate in less regulated conditions, global GHG emissions will actually increase. This is why Congressional proposals to regulate GHG emissions have generally provided for protections to domestic industries that are trade exposed. Executive Order 13563 embodies similar principles, requiring regulations to promote economic growth, competitiveness and job creation by achieving regulatory ends through the least burdensome means. 76 Fed. Reg. 3,821. Given existing PSD regulation and the significant potential costs to the manufacturing sector, including reduced international competitiveness, leakage through trade, and job losses, the EPA should not proceed with additional GHG standards of performance.

Should the EPA decide to consider GHG NSPS for other sectors—over the strong objections of the Associations—it should first proceed with an ANPR that provides significant lead time for the Agency to solicit views and comments from all impacted stakeholders and make a source-category specific endangerment determination for GHG emissions. This would avoid surprise by triggering regulatory obligations on the industry and allow the EPA enough time to understand the complex and varied energy requirements and manufacturing processes involved for various source categories prior to such rules having an unannounced impact. An ANPR would also obviate the need to create dubious legal fictions, such as the "transitional source" category and claims that modified and reconstructed sources are not "new sources" under Section 111. As discussed above, a "sleight of hand" offered to mitigate the costs of a rulemaking only promotes uncertainty, prolongs the regulatory process through litigation, and discourages economic development.

VIII. THE ASSOCIATIONS' MEMBERS WILL BE HARMED BY THE PROPOSED NSPS RULE.

A. The Proposed NSPS Will Constitute a *De Facto* Ban on New Coal-Fired EGUs.

Despite the EPA's unsubstantiated assertion that the proposed rule will have no costs, the proposed standards will significantly harm the Associations' members and the energy and manufacturing sectors as a whole. As explained above, the proposed standards of performance will constitute a *de facto* ban on the development of new coal-fired electric generating capacity because CCS cannot be implemented at a commercial scale. Prior EPA rules, such as the Mercury Air Transport Rule, have already had a significant effect on existing coal-fired EGUs, with more than 60 gigawatts of capacity scheduled to retire by 2020.[78] As the EPA acknowledges, without the proposed rule, a portion would likely be replaced by new coal-fired EGUs. *See* 79 Fed. Reg. at 1,443. This position is further supported by NERA's analysis, which found a "substantial probability" that economic conditions will, in the near term, favor coal-fired EGUs in some parts of the country. NERA at 1.

Eliminating the possibility of new coal-fired EGUs will have a significant detrimental effect on the Associations' members who generate both coal- and petcoke-fired energy and plan to do so in the future and are part of the supply chain for coal and petcoke. Thus, the new rule will reduce options for creating new capacity, as well as demand for coal and petcoke, harming everyone in the supply chain for each product. The increased costs and decreased reliability also will harm the Associations' members who must rely upon efficient, cost effective, and reliable electricity in their operations. Further, the impact of the rule will be felt almost immediately, as EGUs make long-term, strategic decisions regarding future generating capacity. NERA at 1 ("Given the six- to eleven-year lead time necessary for approval and construction of a new coal-fired generator, there is a substantial likelihood that the proposed NSPS will have a near-term impact on the utilities directly regulated by EPA's proposed NSPS in deciding whether, and through what means, to construct additional generating capacity.").

Further, eliminating coal-fired EGUs will reduce fuel diversity for baseload energy, creating an increased risk to grid stability and price volatility. While NGCC turbines are expanding, coal, hydroelectric, and nuclear power markets are contracting due in part to regulatory pressure. The shift away from a diverse baseload power portfolio and toward an ever-increasing reliance on a narrow set of energy sources creates significant risks. Changes in market conditions for energy commodities including natural gas, coal, and petcoke raise significant risks. While the Associations have a strong interest in the production of low-cost natural gas, a balanced portfolio is essential to protect against price volatility and changing market conditions. A *de facto* ban on new coal-fired EGUs would diminish that flexibility. Because many of the Associations' members are large retail electricity consumers, they would be directly impacted by service disruptions or price increases. Even defensive, preparatory measures to guard against grid instability would require expenditure of valuable resources.

The EPA cannot simply ignore all of these impacts by suggesting that market forces alone are dictating a shift from coal to natural gas. The EPA acknowledges that even in these market conditions, coal-fired EGUs serve important functions for reliability and fuel diversity, and will remain viable even under current price spreads. Thus, the EPA is wrong that it is the current cost difference between coal and natural gas that will preclude their future use; instead, the dearth of future coal facilities will arise from the inability of coal-fired EGUs, under any circumstance, to achieve the proposed standard. The EPA cannot hide behind market forces in an attempt to ignore the costs that the proposed rule will impose on the Associations' members.

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[78] Energy Information Administration, *AEO2014 projects more coal-fired power plants by 2016 than have been scheduled* (Feb. 14, 2014), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=15031 (last visited February 19, 2014).

B. The EPA's Inclusion of Simple Cycle Turbines Will Exacerbate Harm to the Associations' Members.

The risk of electricity disruption and price volatility will be increased by the EPA's proposed regulation of simple cycle turbines that are designed to provide peaking power. Unlike baseload NGCC turbines, simple cycle turbines are designed to respond quickly to changing conditions and ensure a consistent, stable supply of electricity despite short-term fluctuations in supply and demand. While the EPA properly excluded simple cycle turbines in the 2012 proposal because of their different purpose and operations, 77 Fed. Reg. at 22,398, the EPA has now reversed course and proposed to regulate them in the same manner as NGCC turbines if they supply more than one third of their potential electric output to the grid over a three-year period.

These changes will infuse more uncertainty into the electricity sector. Regardless of their intended use, simple cycle turbines must respond to fluctuating weather, abnormal power usage, increased reliance on intermittent renewable energy, and unexpected outages from other generators, all of which is beyond their control. Thus, while there is a risk that a simple cycle turbine could exceed the applicability threshold, neither the operator nor its customers would know until after the 3-year compliance period has ended. To mitigate that risk, operators may add emissions controls proactively, subjecting customers to potentially unnecessary costs. Alternatively, they may seek to curtail production as they approach the applicability threshold, exacerbating grid instability. In either case, the increased uncertainty for simple cycle turbines will have ripple effects that harm retail consumers.

C. Application of The NSPS for PSD Permits Will Harm the Associations' Members.

The Associations' members will also be harmed by the application of NSPS emissions limits in PSD permitting decisions. As explained above, the NSPS and PSD programs are closely related, and NSPS standards serve as "BACT floors" for applicable sources. CAA § 169(3). As a result, a final NSPS standard will set the floor for a BACT analysis for any new coal-fired EGU. However, there is also a risk that CCS will be applied as BACT in other permitting decisions for modified coal-fired EGUs. As the EPA explains in the proposed rule:

> In cases where a NSPS is proposed, the NSPS will not be controlling for BACT purposes since it is not a final action and the proposed standard may change, but the record of the proposed standard (including any significant public comments on EPA's evaluation) should be weighed when considering available control strategies and achievable emission levels for BACT determinations made that are completed before a final standard is set by EPA.

79 Fed. Reg. at 1,489 (quoting GHG Guidance); *see also* GHG Guidance at G-1 (NSPS from other source categories may be "a useful starting point" for BACT analyses). Thus, despite the EPA's assertion that the NSPS is not applicable to modified and reconstructed sources, 79 Fed. Reg. at 1.489, the EPA will permit (if not encourage) permit writers to consider the NSPS when making BACT determinations. Thus, while CCS has been consistently rejected in BACT analyses to date, permit writers may rely on the NSPS to determine that CCS is now feasible for PSD permits. Further, it is possible that one or more permit writers would require CCS for other

source categories—including those operated by the Associations' members. Thus, the Associations' members would be harmed by the establishment of a standard that would collaterally and negatively affect the PSD permitting process.

D. The Proposed Rule Is a Necessary Step in the EPA's Plan to Regulate Existing Sources Under Section 111(d).

Finally, the Associations' members will be harmed by a final GHG NSPS because it is a necessary legal step in the EPA's plan to regulate GHG emissions from existing sources under Section 111(d). Section 111(d)(1) states that "[t]he Administrator shall prescribe regulations" that require States to submit plans providing NSPS "for any existing source . . . to which a standard of performance would apply if such a[n] existing source were a new source." While the EPA is legally barred from regulating GHG emissions from fossil-fuel fired EGUs under Section 111(d), *see supra* Section VI, the EPA interprets Section 111(d) to require regulation of existing sources once an NSPS under Section 111(b) is final. *See* 79 Fed. Reg. at 1,462 n.128 (asserting that "CO_2 standards . . . are *required* to be established for existing sources pursuant to CAA Section 111(d)" (emphasis added)). In fact, the EPA has already agreed to "propose and take final action on (1) a rule under CAA Section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da; and (2) a rule under CAA Section 111(d) that includes emissions guidelines for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources." *Id.* at 1,444. In addition, the President has directed the EPA to finalize a GHG NSPS for existing sources by June 1, 2015. *Presidential Memorandum – Power Sector Carbon Pollution Standards*.

Regardless of whether market forces prevent any new coal-fired EGUs from being constructed, there is no question that the regulation of GHG emissions from existing coal-fired EGUs will have a significant impact on those facilities, producers and transporters of coal and petcoke, and retail electricity consumers. And those effects are directly attributable to this rulemaking because it is a legal prerequisite for the regulation of existing sources under Section 111(d). In fact, the EPA acknowledges that the GHG benefits from this rulemaking will come from existing sources, not the new sources directly regulated under Section 111(b). *Compare* 79 Fed. Reg. at 1,496 (regulation of existing sources under Section 111(d) "will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against project climate change impacts and risks"), *with id.* at 1,433 (regulation of new solid fuel-fired EGUs "will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022"). Thus, if the EPA seeks credit for future GHG emissions reductions from existing sources, it cannot ignore the costs and other harms that those emissions reductions will cause for the Associations' members.

E. The Proposed Rule Would Increase the Title V Permitting Fees Paid by the Associations' Members.

Finally, the Associations' members will be harmed because, for the first time, GHG emissions will be used to increase the minimum fee requirements that applicants must pay under Title V. Presumptive minimum fees are calculated based on the mass of "regulated pollutants" that are emitted from a site. *See* 40 C.F.R. § 70.2. However, the definition of "regulated pollutant (for presumptive fee calculation)" is narrow and does not include any of the GHG regulations that the EPA has issued to date. 79 Fed. Reg. at 1491 ("Neither the Light Duty Vehicle Rule nor the Tailoring Rule made any changes that would cause GHGs to meet the definition of 'regulated air pollutant,' or related fee definitions in the title V regulations. The EPA has promulgated no other standards that would trigger fee requirements for GHGs in title V programs."). Thus, even for those facilities that are currently subject to Title V as a result of their GHG emissions, there is no increase in the minimum fee requirements to account for the increased permitting obligations that were triggered by the EPA's interpretation of the PSD and Title V provisions and then adjusted by the Tailoring Rule.

In this proposed rule, however, the EPA has offered two alternative approaches to calculating the minimum fee requirement that propose to impose new costs on any facility subject to Title V permit requirements as a result of GHG regulations under PSD or NSPS. Under each proposal, the EPA exempts GHG emissions from the definition of "regulated pollutant" and then applies an alternative standard to increase Title V permitting fees. Under the first proposal, the EPA would adjust the minimum fee based on the type of GHG permitting process required (i.e. a completeness determination, a request to modify a permit, or a permit renewable) and the prevailing labor costs in the region where the stationary source is located. *See* proposed 40 C.F.R. §§ 70.9, 71.9. Under the second proposal, the EPA would apply a 7% surcharge on the minimum fee requirements for other regulated pollutants as a proxy for the agency's cost in implementing GHG emissions limitations. 79 Fed. Reg. 1494.

Under both proposals, it is clear that the EPA would require for the first time that additional fees must be paid by permit applicants to ensure that a state's permitting agency has sufficient resources to process the Title V permit applications. By imposing these additional fee requirements, the proposed rule would harm the Associations' members who are subject to regulation under Title V, but who have not been required to pay permitting fees based on those emissions. In sum, under either scenario, the proposed rule would harm the Associations because their members are subject to regulations under the Tailoring Rule and will be required to pay additional permitting fees as a result of the EPA's proposed rule.

CONCLUSION

The proposed NSPS GHG rule is arbitrary, capricious, and unlawful for the reasons set forth above. The EPA should immediately withdraw the proposed rule. Should the EPA wish to consider regulating GHGs under the NSPS program, it should first issue an ANPR in order to foster an open, unbiased dialogue with all affected and interested parties, without the threat of imminent applicability of the rule.

The undersigned Associations appreciate the opportunity to comment on this proposal.

American Chemistry Council

American Forest & Paper Association

American Fuel & Petrochemical Manufacturers

American Iron and Steel Institute

American Petroleum Institute

American Wood Council

Brick Industry Association

Corn Refiners Association

Council of Industrial Boiler Owners

National Association of Manufacturers

National Oilseed Processors Association

Portland Cement Association

The Fertilizer Institute

U.S. Chamber of Commerce

ATTACHMENT A

NERA
ECONOMIC CONSULTING

AEO 2014 Demonstrates a Substantial Probability that New Coal-Fired Generators will be Economical in the Absence of NSPS

Prepared for:

National Association of Manufacturers and
U.S. Chamber of Commerce

Final Report

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I. INTRODUCTION

On September 20, 2013, U.S. EPA released an updated new source performance standard (NSPS) for carbon dioxide emissions from new fossil-fired electric generators. EPA determined that based on "existing and anticipated economic conditions" that there would be few (if any) new coal-fired generators built and thus the costs of this proposed rule would be "negligible."[1]

Both public empirical data and statistical theory show that there is a substantial probability that, in one or more regions in the United States in the next decade (or sooner), new coal-fired builds will be a preferred economic choice over other alternatives including natural gas-fired builds. Given the six- to eleven-year lead time necessary for approval and construction of a new coal-fired generator, there is a substantial likelihood that the proposed NSPS will have a near-term impact on the utilities directly regulated by EPA's proposed NSPS in deciding whether, and through what means, to construct additional generating capacity. Accordingly, EPA's adoption of a rule preventing the choice of new coal-fired builds would cause economic harm to the utilities that must forego building new coal-fired generators that otherwise would be built or that must build new capacity with increased costs imposed by the proposed NSPS. That impact, in turn, would cause harm to electricity consumers served by the generators in question, and would cause harm to workers and suppliers of equipment specific to coal-fired generation.

While new baseload additions today are almost exclusively natural gas-fired combined cycle (partly because of the proposed NSPS), there is a substantial likelihood that new coal-fired builds without carbon capture and storage (CCS) would have a role in the absence of the proposed NSPS. This conclusion is supported by the U.S. government's most prominent long-term energy forecast, the Energy Information Administration's (EIA's) *Annual Energy Outlook* (*AEO*).

As part of this forecast, the EIA projects electric capacity additions (and retirements) based upon certain underlying assumptions and economics of the specific scenarios being evaluated. Even under the *AEO 2014* Reference Case forecast, which projects outward a plentiful natural gas supply, EIA forecasts a role for new coal-fired builds without CCS. Likewise, under the *AEO 2014* Low Oil and Gas Resource forecast, there is an even greater role for new coal-fired builds without CCS. Further, *AEO 2014*'s forecasts (in both the *AEO 2014* Reference and Low Oil and Gas Resource cases) add 3 percentage points to the cost of capital for new coal-fired generators. The *AEO 2014* forecasts assume this penalty for new coal-fired generators (but not other types of new generators). This assumption skews investment decisions in the *AEO 2014* forecasts. One *AEO 2014* case, EIA's No GHG Concern case, properly removes this assumption. In that scenario, EIA forecasts an increase in the number of new coal-fired builds (relative to the *AEO 2014* Reference case) and accelerated construction of such new coal-fired builds. If the No GHG Concern case included natural gas supply assumptions more consistent with the *AEO 2014* Low

[1] *Federal Register*, Vol. 79, No. 5, January 8, 2014. The updated NSPS was released in September 2013, but not published in the *Federal Register* until January 2014.

Oil and Gas Resource case, then the forecasted quantity of new coal-fired builds would be increased further and the timing for those new coal-fired builds would be further accelerated.

Based upon our review of the *AEO 2014* forecasts, we conclude that new coal-fired builds without CCS would continue to have an important role within the electricity sector.[2] There are regions in the United States in which coal-fired capacity additions without CCS are chosen by the NEMS model (the model used by EIA in *AEO 2014*) because they can provide baseload electricity at a lower cost than any available alternative, including natural gas. Thus, an inability to choose new coal-fired builds without CCS will cause harm to the electricity generation industry and consumers of electricity who will face higher costs in those regions.

Indeed, there is a substantial likelihood that, in the absence of the proposed NSPS rule, one or more new coal-fired generators would begin construction in the next few years, as evidenced by the projects under development that EPA cited in its proposed rule. These projects in Michigan, Georgia, and Kansas have demonstrated a desire on the part of their respective developers to move forward with their development, if the proposed NSPS did not exist.

[2] We also conclude that given the high costs of CCS, new coal-fired generators <u>with</u> CCS would not be economical or, at a minimum, would be more costly than new coal-fired generators <u>without</u> CCS.

II. THERE IS A ROLE FOR NEW COAL-FIRED GENERATING CAPACITY WITHOUT CCS

The *AEO*, produced annually by the EIA, forecasts the future capacity mix within the electricity sector. Because of the uncertainties in how energy markets will develop and evolve, the EIA analyzes a number of different cases in each edition of its *AEO*. *AEO 2014* includes results for a number of different cases, which have varying applicability with respect to determining the impact of the proposed NSPS. The EIA utilizes the NEMS model for all of its AEO forecasts. The NEMS model represents existing generators and provides costs and characteristics for a suite of new fossil fuel and non-fossil fuel generators to meet increasing electricity demand or to replace retired capacity.

A. AEO 2014 Reference Case

The *AEO 2014* Reference case does not include the proposed NSPS for new fossil generators (nor do any other cases).[3]

Under the *AEO 2014* Reference case market conditions, the NEMS model finds new coal-fired builds to be economical in the future. In 2039 and 2040, there would be a combined 133 MW of new coal-fired generating capacity (without CCS) that comes online in the Texas Regional Entity.[4]

For the reasons discussed below, we do not believe that the *AEO 2014* Reference case is an appropriate case for evaluation of the proposed NSPS, however, because it includes a 3 percentage point addition to the cost of capital for new coal-fired generating capacity without CCS (and coal-to-liquids plants without CCS). We believe that removing this assumption would provide for a more impartial assessment of the economics of new coal-fired builds.

B. AEO 2014 No GHG Concern Case

As part of *AEO 2014*, EIA evaluated one case that does not include the 3 percentage point addition to the cost of capital for new coal-fired generating capacity without CCS. We believe that this case is the most appropriate starting point for evaluating the impact of the proposed NSPS. The *AEO 2014* No GHG Concern case modeled by EIA includes all of the assumptions from the *AEO 2014* Reference case, but removes the 3 percentage point addition to the cost of capital for new coal-fired generating capacity. EIA included this penalty beginning in *AEO*

[3] *Annual Energy Outlook 2014*, p. CP-14.

[4] There is an additional 330 MW of coal-fired capacity that comes online in 2017 and 2018, but we believe that this is coal-fired capacity with CCS, that is partially funded under the Clean Coal Power Initiative program, part of the ARRA of 2009. These additions appear to be added in all *AEO 2014* cases, but there is no evidence that such “unplanned” builds of coal-fired generators with CCS will be added, particularly in that time frame.

2009, but it is unreasonable to include this penalty as part of an evaluation of the impact of the proposed NSPS for new fossil generators.[5]

The inclusion of the 3 percentage point addition to the cost of capital coincided with a number of efforts to enact policies to put a price on carbon emissions. Since that time, the likelihood of the adoption of a cap-and-trade or a carbon tax program has declined dramatically. Thus, it is now quite <u>unlikely</u> that new fossil-fired generators would be faced with a national price on carbon in the foreseeable future from such programs. Further, EIA's approach puts an undue penalty on new coal-fired generators without placing any similar penalty on other new fossil-fired generators, like natural gas combined cycle generators, even though if there were to be a price on carbon, the costs on these units would also increase.

The 3 percentage point addition to the cost of capital imposes a significant cost on potential new coal-fired generators in the model (even though it is not a concrete or real cost that these units would be expected to face) and serves to distort the economics of new coal-fired generators relative to other technologies, especially new natural gas-fired generators.

The results for the *AEO 2014* No GHG Concern case show that coal-fired generators would be economical to build, with the first new units coming online starting in 2026, with additional coal-fired builds in each year through 2040 (the last year of the analysis), and cumulative economic new builds of almost 10.5 GW distributed across 10 different electricity market regions.

Table 1 contains the full list of new builds by region and online year. Elimination of the 3 percentage point addition to the cost of capital results in more new coal-fired builds and construction that occurs at earlier dates, as compared to the *AEO 2014* Reference case.

[5] "In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning. The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected." See "Levelized Cost and Levelized Cost of New Generation Resources in the Annual Energy Outlook 2014," available at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

Table 1: New Coal-Fired Generator Additions (Without CCS) in AEO 2014 No GHG Concern Case (MW)[6]

Region	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Texas Regional Entity		124	133		206	154	254	177	150	136	155	175	201	196		2,063
Florida Reliability Coordinating Council		114	132		97	139	180	156	120	145	129	146	146	149	131	1,783
SERC / Delta			99			68	69									236
SERC / Southeastern				118				72	86	104	101	104	104	102		791
SERC / Central	68		89	111	98	115	113	128	131		469	388	347	456	236	2,749
Virginia / Carolinas											81	109	100	111		400
Southwest Power Pool / South			65					66		71				77		280
WECC / Southwest						78	92	98	105		114	124	121	129		862
WECC / NW Power Pool		93			76	80	74	77	84		88	76	81	94	108	929
WECC / Rockies									71		77		90		130	368
Total All Regions	68	331	519	229	477	634	782	774	746	457	1,214	1,122	1,191	1,315	606	10,462

[6] AEO 2014, Total All Regions from Electric Generating Capacity Table; Regional numbers from Electric Generating Capacity by Electricity Market Module Region and Source. All data tables for AEO 2014 available at http://www.eia.gov/oiaf/aeo/tablebrowser/.

As mentioned above, the *AEO 2014* No GHG Concern case adopts the assumptions from the *AEO 2014* Reference case. The most important assumptions made by EIA for purposes of this analysis concern fossil fuel resources and production technology, which are primary drivers of both natural gas and coal prices, environmental regulations, and costs of new natural gas- and coal-fired generation.

C. AEO 2014 Low Oil and Gas Resource Case

Since the supply and cost of extracting shale gas throughout the United States cannot be known with certainty into the future, the EIA also considers a Low Oil and Gas Resource case in its *AEO 2014*. This case assumes lower estimated ultimate recovery (EUR) per shale gas and tight gas well. This Low Oil and Gas Resource case results in higher natural gas prices than in the *AEO 2014* Reference case. Like the *AEO 2014* Reference case, this case also includes the 3 percentage point addition to the cost of capital for new coal-fired generating capacity without CCS, which we feel is inappropriate. A review of the results of this case, however, provides information on how higher natural gas prices would affect the economics of new coal-fired builds relative to new natural gas-fired builds.

This scenario results in significantly more economical builds of new coal-fired generators (without CCS), as compared to the *AEO 2014* Reference Case. Under this scenario, beginning in 2031 and continuing through 2040, approximately 2.7 GW of new coal-fired builds (without CCS) would come online in six different electricity regions. These new builds are listed in Table 2 by region and online year.

Table 2: New Coal-Fired Generator Additions (Without CCS) in AEO 2014 Low Oil and Gas Resource Case (MW)[7]

Region	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**Total**
Texas Regional Entity	666	88	191	128	155	144	157		174	176	1,880
SERC / Delta	132										132
SERC / Central	90	83			66		70				309
Southwest Power Pool / South						77	73				150
WECC / NW Power Pool								152			152
WECC / Southwest										66	66
Total All Regions	888	171	191	128	221	221	300	152	174	243	2,689

D. Combined Findings from *AEO 2014* Cases

The *AEO 2014* Reference and Low Oil and Gas Resource cases demonstrate that new coal-fired builds are expected to be an economical baseload capacity option in the future. However, both of these cases contain the 3 percentage point addition to the cost of capital for new coal-fired generators (without CCS), which significantly limits the forecasts of new economical builds of coal-fired generators.

The *AEO 2014* No GHG Concern case demonstrates that removing the 3 percentage point addition to the cost of capital significantly affects the quantity and timing of new coal-fired builds. With the 3 percentage point addition, it would be economical for new coal-fired builds of 133 MW coming online in 2039 and 2040 (*AEO 2014* Reference case); without the 3 percentage point addition, there would be almost 10,500 MW of coal-fired builds coming online beginning in 2026 (*AEO 2014* No GHG Concern case).

A comparison of these EIA data confirms that imposition of regulatory burdens (such as NSPS) on the construction of new coal-fired generators would have a concrete impact on EIA's forecast of the number of such new coal-fired projects as well as the timing of those projects.

Further, if the natural gas supply were to be lower than that forecast in the *AEO 2014* Reference case (thereby resulting in higher natural gas prices), then it would likely be economical for new coal-fired builds to come online even earlier than 2026. For context, if we compare the Henry Hub natural gas prices in the *AEO 2014* Reference and Low Oil and Gas Resource cases, we see

[7] AEO 2014, Total All Regions from Electric Generating Capacity Table; Regional numbers from Electric Generating Capacity by Electricity Market Module Region and Source. All data tables for AEO 2014 available at http://www.eia.gov/oiaf/aeo/tablebrowser/.

that prices in the Low Oil and Gas Resource case are higher than those in the Reference case by $0.90/MMBtu (2012$) in 2020, and this difference increases to $1.64/MMBtu in 2025, with longer term differences approaching $3.00/MMBtu by 2040. Such an outlook would significantly raise the projected costs of new natural gas-fired combined cycle builds, thereby making new coal-fired builds relatively more economical. While we cannot precisely determine how much earlier we would expect to see new coal-fired generators if (1) natural gas prices were to be more like those in the *AEO 2014* Low Oil and Gas Resource case and (2) the 3 percentage point addition to the cost of capital was removed, we can state with confidence that we would see increases in new coal-fired builds (relative to the *AEO 2014* No GHG Concern case) and such new coal-fired builds would come online prior to 2026.

The new coal-fired builds by case are summarized in Table 3. If EIA had modeled the No GHG Concern case with the assumptions of the Low Oil and Gas Resource case, that forecast would have included more than the 10,462 MW of new coal-fired generator additions that were in the No GHG Concern case (with Reference case natural gas supply assumptions) and such new coal-fired builds would have begun coming online prior to 2026, when they first appeared in the No GHG Concern case (with Reference case natural gas supply assumptions).

Table 3: Summary of New Coal-Fired Generator Additions by AEO 2014 Case

Case	**Total "Unplanned" Coal-Fired Generator Additions (MW) (through 2040)**	**First Year Online of "Unplanned" Coal-Fired Generator Additions**
No GHG Concern	10,462	2026
Reference	133	2039
Low Oil and Gas Resource	2,689	2031
Low Oil and Gas Resource with No GHG Concern	*More than 10,462*	*Prior to 2026*

E. Expected Future Policy Measures Would Likely Lead to More Need For New Coal-Fired Builds

Other issues affecting the fuel mix and need for new generation capacity have to do with coal and nuclear retirements in the *AEO 2014* Reference case.

Since the *AEO 2014* Reference case includes only policies in effect at the time of its preparation,[8] *AEO 2014* does not include the retirements of additional coal units likely to be caused by upcoming policies such as coal combustion residuals, 316(b) cooling water rule, effluent guidelines, and tightening of ozone National Ambient Air Quality Standards (NAAQS).[9] Further, *AEO 2014* does not retire existing nuclear generators at the end of their 60-year life,

[8] With the exception of the 3 percentage point addition to the cost of capital for a new coal-fired power generator.

[9] EIA is limited to modeling existing policies in its Reference Case.

except in an Early Nuclear Retirement sensitivity case, which, as demonstrated by several recent license challenges and related retirements, is at least equally likely as their being granted licenses for another 20 years of operation.[10] Therefore the *AEO 2014* Reference case may likely underestimate the number of coal and nuclear unit retirements.

The potential for higher levels of coal and nuclear unit retirements are at least partially addressed in a case from *AEO 2014*, the Accelerated Nuclear and Coal Retirements case. As part of this case, nuclear generators retire at the end of their projected 60-year life and existing coal generators are presented with higher costs leading to greater coal retirements. By 2040, coal-fired and nuclear generation capacity is reduced by about 50 GW and 40 GW, respectively, with the bulk of this capacity being replaced by new natural gas combined cycle units (increase by more than 60 GW in 2040). The greater reliance on natural gas in the electricity sector leads to increased total demand for natural gas of about 1.25 quads in 2020 to more than 3 quads in 2040, which in turn leads to higher Henry Hub natural gas prices over time. If the natural gas-fired generation increases are higher than those in the *AEO 2014* Accelerated Nuclear and Coal Retirements case, then the Henry Hub price increases would likely be larger.

Taking into account future policies that would cause additional coal retirements and an equally valid set of assumptions on nuclear retirements leads to greater natural gas-fired generation and hence, natural gas demand being likely greater in the electricity sector. This greater demand would increase natural gas prices. Similarly, with less coal-fired generation there would be less demand for coal, which would be expected to lower delivered coal prices.[11] The combination of higher delivered natural gas prices and lower delivered coal prices would improve the relative economics of new coal-fired generators relative to new natural gas-fired generators.

F. EIA's Assumptions about Capital Life are Biased Against New Coal-Fired Builds

There are also other assumptions that underlie the analyses in *AEO 2014*, that lead to a systematic bias against new coal-fired generators (and similarly that benefit new natural gas-fired generation). EIA assumes that all generating technologies must recover their costs over a 30-year time horizon and this is reflected in each technology's capital charge rate. The assumed 30-year life is appropriate for natural gas combined cycle generators. However, when utilities evaluate generation technologies, they vary the cost recovery with the type of technology. EIA understands this point and states, "In reality, the cost recovery period and cost of capital can vary

[10] In *AEO 2009*, EIA retired nuclear units at the end of their 60-year operating life, but then starting with *AEO 2010*, such retirements were not included in their Reference case, but were evaluated in other cases.

[11] Coal prices would also likely decline if there were to be decreased coal demand. This cannot be evaluated with the *AEO 2014* Accelerated Nuclear and Coal Retirements case because the manner in which coal retirements were accelerated included an assumption about reduced coal mine productivity and increases in coal transportation costs. See "Implications of accelerated power plant retirements," U.S. EIA, available at http://www.eia.gov/forecasts/aeo/section_issues.cfm#power_plant.

by technology and project type."[12] In particular, a new coal-fired generator is typically evaluated over a 40-year period.[13] Assuming a 30-year life for new coal-fired generators forces their owners to recover all of their costs over a 30-year time horizon, rather than the more standard 40-year time horizon. For example, if a new coal-fired generator could not recover its costs over a 30-year time horizon, but could do so over a 32-year time horizon, it would not be built in *AEO 2014*, but would likely be built in reality. This systematic bias against longer-lived assets like new coal-fired generators and/or new nuclear generators leads to an understatement of the amount of new coal-fired generator builds.

If the differentiated cost recovery periods had been implemented in *AEO 2014*, then the forecasts would likely have seen new coal-fired generators built earlier in time and in greater quantities than are shown in the *AEO 2014* cases.

G. Timetable for New Coal-Fired Generators

To better understand the economic impact of the proposed NSPS, it is helpful to understand the timing of events that precede the construction and initial operations for a new coal-fired generator. EIA estimates the construction time for a new coal-fired generator to be four years, which does not include time for permitting. We reviewed the timetables for new coal-fired generators that have come online in the United States in 2012 and 2013 (see Table 4), and estimate that the total time once a developer decides to build a new coal-fired generator until that generator comes online is between six and eleven years.[14] Thus, if a developer were to decide today to build a new coal-fired generator, it could likely begin operating between 2020 and 2025 (both depending primarily on the timetable for permitting).

[12] See http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

[13] See for example Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 5.13, included as part of EPA's IPM Model documentation. Available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_8.pdf.

[14] As additional support for this timetable we present information on two of the potential new coal-fired generators that have yet to be constructed. The proposed new Holcomb plant in Kansas, initially sought a permit in 2006. It received a permit from the Kansas Department of Health and Environment in December 2010. That permit was invalidated in October 2013, and now Sunflower, the developer is continuing to evaluate its options almost eight years after it initially sought a permit. See http://www.holcombstation.com/2010/12/sunflower-receives-air-permit-for-holcomb-expansion-project/ and "Kansas Supreme Court Reverses Holcomb Coal Plant Air Permit," *Environment New Service*, October 2013, available at http://ens-newswire.com/2013/10/07/kansas-supreme-court-reverses-holcomb-coal-plant-air-permit/.

Also, the Washington County project in Georgia first sought permits in January 2008 from the Georgia Environmental Protection Department (EPD). In April 2010, it received final permits. In December 2010, a state court rejected the air permits for the plant. In November 2011, Georgia EPD re-issued the air quality permit. The plant is now in limbo due to the proposed NSPS (see Section II.J). See http://www.greenlaw.org/PlantWashington.

Table 4: Timing for Recently-Constructed Coal-Fired Generators

Plant Name	State	1st Mention	Final Air Permit Date	Began Construction	Online Date	Elapsed Time (1st Mention to Online)
Longview Power	WV	2002	Mar-04	Feb-09	Jan-12	10 years
Prairie State	IL	2001	Apr-05	Oct-07	Jun-12	11 years
Virginia City	VA	Jun-05	Jun-08	Jun-08	Jul-12	7 years
John W Turk	AR	Aug-06	Jan-10	Nov-08	Dec-12	6 years
Cliffside 6	NC	Jun-06	Feb-08	Jan-08	Dec-12	6 years
Sandy Creek	TX	2006	Jul-07	Apr-08	May-13	7 years
Edwardsport IGCC	IN	Sep-06	Jan-08	Mar-08	Jun-13	7 years

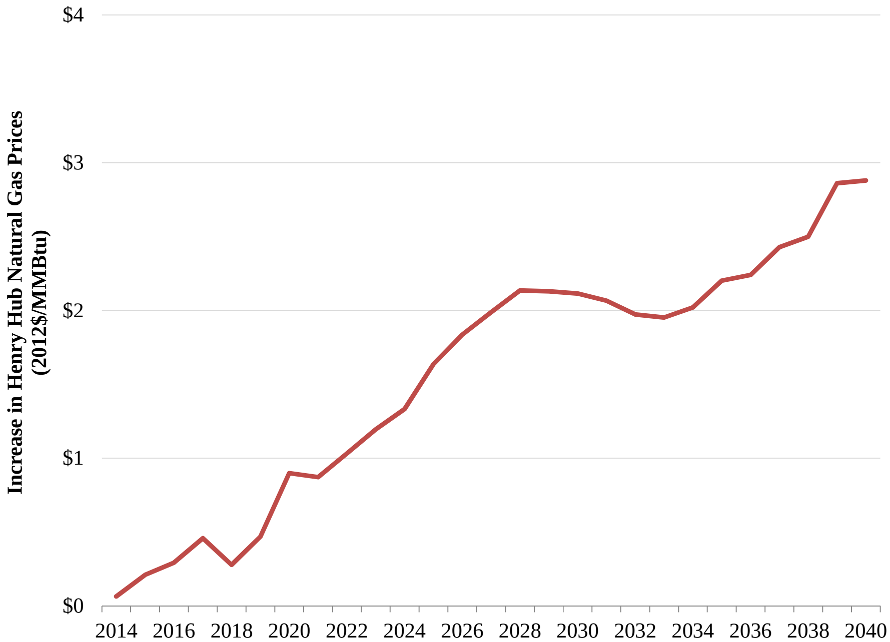
If a developer believed that the current natural gas market was likely to shift to higher natural gas prices in the near future (like those in the *AEO 2014* Low Oil and Gas Resource case), and it would be economically advantageous to build new coal-fired generators in certain regions, then the permitting process for a new coal-fired build would begin in the near future. Given the relatively long permitting and construction schedule for building new coal-fired generators, we would then expect to see such new builds come online between 2020 and 2025. Such timing is consistent with the modeling results from *AEO 2014* and the results that we would see if we were to apply some of the assumption changes described above.

In the *AEO 2014* No GHG Concern case, EIA projects new builds of coal-fired generators coming online in 2026, which means that planning and permitting activity would have to start within the next one to six years.

H. Different Natural Gas Price Forecasts Affect Capital Investment Decisions

There are a number of uncertainties about natural gas prices that are explored by EIA in *AEO 2014*. In the *AEO 2014* Low Oil and Gas Resource case, natural gas prices are significantly higher than in the Reference case (see Figure 1). Even in this case, shale gas production rises from 9.62 Tcf in 2015 to 12.54 Tcf in 2025. An even larger natural gas price variance arises from potential litigation and regulation scenarios.

Figure 1: Comparison of Henry Hub Natural Gas Prices in AEO 2014 – Low Oil and Gas Resource less Reference (2012$/MMBtu)



I. Utilities Perform Scenario Planning to Include Key Uncertainties

EIA assigns no probabilities to its different *AEO 2014* cases. Instead, each case represents the consequences that would appear in the market if the conditions assumed in constructing it were realized. To address the fact that there are a number of ways in which the market could develop, many utilities employ scenario analysis to design robust investment plans that take the reasonable range of developments or pathways into account.

The *AEO 2014* Low Oil and Gas Resource case is a very reasonable scenario for high natural gas prices and that scenario (or one like it) is likely to be used in such scenario planning exercises. Since this case leads to the conclusion that some number of new coal-fired generators would have lower levelized costs than new natural gas-fired generators, a utility using scenario analysis to develop an investment plan that is robust across all plausible scenarios would have a substantial likelihood of including new coal-fired generators in that plan.

Even if investment decisions are made on an expected value basis rather than by a determination of robust investment plans across scenarios, the diversity of probability assessments made by potential investors about future coal and natural gas prices makes it substantially likely that some investors would choose new coal-fired builds in the absence of the proposed NSPS. There is a diversity of opinions among potential investors in coal-fired power about the likelihood of specific sets of conditions that affect fuel prices, and therefore different decision makers will assign different probabilities to scenarios for high natural gas prices (or the spread between natural gas and coal prices). That diversity of probability assessments, and the number of unique events that would trigger high natural gas prices, makes it substantially likely that some decision makers will see the *AEO 2014* Low Oil and Gas Resource case as being sufficiently likely that they would include new coal-fired builds in their portfolio.

EPA admitted this in its RIA:

> *The RIA added, elsewhere, the following caveats: "It is important to note that this analysis is based on assumptions regarding the average national cost of generation at new facilities. As reported by the EIA [DOE's Energy Information Administration], there is expected to be significant spatial variation in the costs of new generation due to design differences, labor wage and productivity differences, location adjustments, among other potential differences. EPA acknowledges that there is some uncertainty around these estimates, and is unable to provide estimates for all variants. However, the results are expected to hold for the majority of situations. The analysis also does not explicitly consider new units designed to combust waste coal or petroleum coke (pet coke), which may be affected by this rule, but also may exhibit different local economics."*[15] (footnotes omitted)

J. Diverse Circumstances Make Choices in Favor of New Coal-Fired Builds Highly Likely

EIA projections of generating capacity additions necessarily rely on average economic conditions in each region because it is impossible to capture the unique situation of every individual investment decision in its, or any other, model. The mathematical result of this kind of averaging is to leave out generation choices that are very likely to occur in specific regions. That is, averaging consolidates a distribution of numbers into one average number. By excluding some of the variation and diversity (or the distribution of situations), the EIA (through *AEO 2014*) under-represents the circumstances in which coal-fired generation would be economically advantageous relative to natural gas. In other words, even if new natural gas-fired generators *on average* throughout the United States might be less costly than new coal-fired generators, that does not mean that in all instances the natural gas-fired generators would be less costly than coal-fired generators in all such regions. There is a substantial likelihood that new coal-fired generators will be preferred to new natural gas-fired generators in some instances over the next decade even if, *on average*, new natural gas-fired generators are projected to be less costly.

In the U.S. electrical system, there is a great deal of diversity across the country in region-specific conditions that affect the economics of new coal-fired generators versus new natural gas-fired generators. Based on EIA's forecasts, over the next 10 years, there likely will be at

[15] 19 EPA 2012 RIA, p. 5-1. Cited in "EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers," James E. McCarthy Specialist in Environmental Policy CRS September 30, 2013. See EPA 2012 RIA, p. 5-17.

least 100 GW of new generating units built, which would likely account for more than 200 individual power plants, of which at least 100 are likely to be baseload generators. With this number of independent investment decisions, application of probability theory shows that there is a substantial likelihood that new coal-fired builds will be preferred to natural gas-fired builds.

We see empirical evidence of this in the three examples given of current plans to build coal-fired generation (see following section), and EIA's modeling (in its No GHG Concern case) confirms that in every year starting in 2026 a new coal-fired generator would be brought online because it was found to be preferable to alternatives in the absence of the proposed NSPS.

K. There are Coal Plants Waiting to Be Built Today

As part of the proposed NSPS rule, EPA specifically cited three new coal-fired generation projects that may not be subject to the NSPS rulemaking. The three projects cited in the rule are:

- Wolverine EGU project in Rogers City, Michigan,
- Washington County project in Georgia, and
- Holcomb project in Kansas.[16]

At the time the proposed NSPS was released, these three projects were under development. The Wolverine project was cited as a "project presently under development that may be capable of 'commencing construction' for NSPS purposes."[17] The other two projects were also under development, and their respective developers "represented that the projects have commenced construction for NSPS purposes."[18]

Since the proposed NSPS was released, the Wolverine project has been cancelled. Wolverine cited the proposed NSPS as the reason for the cancellation, "It appeared to us that they were not going to allow a coal plant to be built. It's that simple."[19]

In April 2013, POWER4Georgians, the developer of the Washington Country project, signed a contract with IHI Corporation for the boiler for the new coal plant. Also, the Georgia Environmental Protection Division has issued the necessary permits for the plant.[20]

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[16] Source: EPA Proposed Rule, available at https://www.federalregister.gov/articles/2014/01/08/2013-28668/standards-of-performance-for-greenhouse-gas-emissions-from-new-stationary-sources-electric-utility.

[17] EPA Proposed Rule, Paragraph Citation 79 FR 1461.

[18] EPA Proposed Rule, Paragraph Citation 79 FR 1461.

[19] "Wolverine ends plant speculation in Rogers City," *The Alpena News*, December 17, 2013. Available at https://www.thealpenanews.com/page/content.detail/id/527862/Wolverine-ends-plant-speculation-in-Rogers-City.html?nav=5004.

The Holcomb project had its air permit invalidated by the Kansas Supreme Court in October 2013 due to failures of the Kansas Department of Health and Environment to include compliance with the latest Federal one-hour standards for nitrogen oxides and sulfur oxides. At the time, Sunflower, the project's developer said it was not intending to abandon the project.[21]

These three projects represent three separate examples of developers seeking to build new coal-fired generators (without CCS) today, even though the economic conditions that *AEO 2014* projects would not lead to any economic builds of new coal-fired generators today. These three projects are examples of how region-specific economic conditions and different market expectations by developers have led to an economic desire to build new coal-fired generators in the immediate future.

[20] See http://power4georgians.com/docs/P4G%20Release%20-%20Boiler%20Contracts%2004-13-13%20FINAL.pdf.

[21] "Kansas Supreme Court Reverses Holcomb Coal Plant Air Permit," *Environment News Service*, October 7, 2013. Available at http://ens-newswire.com/2013/10/07/kansas-supreme-court-reverses-holcomb-coal-plant-air-permit/.

III. CONCLUSIONS

Our review of *AEO 2014*, the U.S. government's long-term energy forecasts, shows that it is substantially likely that there will be an economic benefit to building new coal-fired generators (without CCS) and having them come online early in the next decade (2020 to 2025), with final decisions to move forward and build a new coal-fired generator needing to take place in the very near future (the next one to six years). If the proposed NSPS is finalized in its current form, these economic new builds of coal-fired generators would be prohibited (or, at a minimum, made more costly), which would cause economic harm to the utilities that would seek to build them, the ratepayers who would be forced to incur higher electricity rates, and all of the companies that would be important suppliers in building and maintaining the operations of the new coal-fired generators.

In the absence of this proposed rule, it appears substantially likely that one or more new coal-fired generators without CCS would begin permitting or construction in the next few years, as evidenced by the projects under development that EPA cited in its proposed rule. These projects in Michigan, Georgia, and Kansas have demonstrated a desire on the part of their respective developers to move forward with their development, if the proposed NSPS were to no longer exist.

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