EPA's Proposed New Source Performance Standards to Control Greenhouse Gas Emissions From Electric Utility-Generating Units

by Arnold W. Reitze Jr.

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The U.S. Environmental Protection Agency (EPA), on April 13, 2012, promulgated proposed new source performance standards (NSPS) to limit carbon dioxide (CO_2) emissions from new electric-generating units (EGUs) greater than 25 megawatt electric (MWe) located in the continental United States.[1] The standards are based on the emissions produced by a natural gas combined-cycle (NGCC) facility. EPA does not expect any coal-fired EGU to meet this standard without utilizing carbon capture and storage (CCS) technology to prevent 50% or more of the CO_2 emissions from being released to the atmosphere.

This proposed rule is the latest effort by EPA to deal with a dilemma created by the U.S. Supreme Court when, in April 2007, the Court held that greenhouse gases (GHGs) were air pollutants under the Clean Air Act (CAA).[2] In the United States, about 84% of the GHG emissions are CO_2, and electric power plants accounted for about 40% of the CO_2 emissions in 2010.[3] One hundred facilities reported emissions greater than seven million metric tons of carbon dioxide equivalent (CO_{2e}), and 96 of these facilities were electric power plants.[4] This is the reason that CO_2 is the primary target for control. For more than 40 years, EPA has implemented the CAA to reduce air pollution by requiring improved combustion of fossil fuel or by requiring the use of equipment that would capture air pollutants prior to their release to the atmosphere. CO_2 emissions, however, are different from the other pollutants that are regulated by the CAA. CO_2 emissions are an integral part of the chemistry of combustion and cannot be prevented from formation. Moreover, no commercially demonstrated, cost-effective, post-combustion technology exists to prevent their release, which is a prerequisite for any technology used to develop NSPS pursuant to the CAA's §111. NSPS are to be established for new and modified sources in various industrial categories based on the capability of available technology,[5] after considering costs, non-air quality health and environmental impacts, and energy requirements.[6] There is no emission threshold for triggering the applicability of NSPS; therefore, almost all changes to existing facilities potentially can trigger NSPS applicability. The CAA directs the Administrator to review and, if appropriate, revise NSPS at least every eight years.[7] Environmentalists seek to have GHG requirements included in revised NSPS, but industry advocates and their congressional supporters resist these efforts. Now that CO_2 is a regulated pollutant under the CAA,[8] it is difficult for the Agency to avoid adding CO_2 requirements to NSPS as they are revised. Nevertheless, EPA's commitment to imposing GHG standards in revised NSPS was ambiguous until March 2012.

EPA did not regulate CO_2 in its NSPS for petroleum refineries, which resulted in lawsuits being filed by environmental groups that were consolidated in the U.S. Court of Appeals for the District of Columbia (D.C.) Cir-

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1. U.S. EPA, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22392 (Apr. 13, 2012).
2. Massachusetts v. EPA, 549 U.S. 497, 37 ELR 20075 (2007). 42 U.S.C. §§7401-7671q, ELR Stat. CAA §§101-618.
3. U.S. EPA, *2012 U.S. Greenhouse Gas Inventory Report, Executive Summary* ES-5 (Apr. 2012).
4. Andrew Childers & Avery Fellow, *Power Plants Accounted for 72 Percent of Greenhouse Gases Reported in 2010*, 43 Env't Rep. (BNA) 80 (Jan.13, 2012).
5. CAA §111, 42 U.S.C. §7411.
6. CAA §111(a), 42 U.S.C. §7411(a).
7. CAA §111(b)(1)(B), 42 U.S.C. §7411(b)(1)(B).
8. U.S. EPA, *Endangerment and Cause or Contributing Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496 (Dec. 15, 2009); U.S. EPA, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 75 Fed. Reg. 25524 (May 7, 2010) (codified at 40 C.F.R. pts. 85, 86, 600).

cuit.[9] Subsequently, EPA agreed to issue a proposed rule by December 10, 2011, and a final rule by November 10, 2012.[10] The rule is to impose standards of performance for GHGs at refineries, and EPA will issue emissions guidelines for existing refineries pursuant to CAA §111(d).[11] In November 2011, EPA announced it would miss the deadline and asked for additional time to comply.[12]

EPA promulgated NSPS and national emission standards for hazardous air pollutants (NESHAPs) for the Portland cement industry, on September 9, 2010, without GHG standards.[13] The regulations were challenged in the D.C. Circuit by industry and environmentalists, which resulted in the court upholding the NSPS, but remanding the NESHAP rule.[14] The court held that EPA's decision to collect additional data before it proposes GHG NSPS standards means that there is no final Agency action to be reviewed.[15]

In June 2011, EPA promulgated a final rule amending the NSPS for stationary diesel engines, but the rule does not include GHG emission limits.[16] On October 14, 2011, EPA proposed an NSPS review for nitric acid plants.[17] EPA discussed the possibility of regulating the GHG nitrous oxide (N_2O), but did not propose standards. The Agency, however, is encouraging the control of nitrogen oxide (NO_x), which also controls N_2O.[18]

On April 18, 2012, EPA released NSPS and NESHAPs for the oil and natural gas sector.[19] This final rule is applicable to the production phase of the natural gas and oil industry and the related storage and processing. It is aimed primarily at reducing by nearly 95% the volatile organic compounds (VOCs) released from natural gas wells that are hydraulically fractured. The production and processing of natural gas is responsible for nearly 40% of U.S. emissions of methane, a GHG 20 times as potent as CO_2.[20] Methane emission reductions are expected to be a co-benefit of reducing VOC emissions from new and modified wells.

The most significant effort by EPA to use NSPS to control GHG emissions is its 2012 proposal to impose CO_2 limits for EGUs, which is the subject of this Article. EPA published NSPS for criteria pollutant emissions from most EGUs on February 27, 2006, but it did not regulate GHG emissions.[21] Two groups of petitioners, states and environmental organizations, petitioned for judicial review of this rule in the D.C. Circuit, contending, among other things, that the rule should be required to have standards of performance established for GHG emissions from EGUs.[22] The portions of the state and environmental petitioners' petitions for review of the 2006 Final Rule that related to GHG emissions were severed from other petitions for review of that rule, and were pending before the D.C. Circuit[23] when the Supreme Court decided *Massachusetts v. EPA*.[24] After the Supreme Court's decision that GHGs were air pollutants, the Agency made the required finding that GHGs endanger public health and welfare.[25] The D.C. Circuit, in response to a motion from EPA, remanded the 2006 Final Rule for further consideration of the issues related to GHGs. Subsequently, the state and environmental petitioners and EPA negotiated a proposed settlement agreement that set deadlines for EPA to propose and take final action on: (1) a rule under CAA §111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 C.F.R. Part 60, subpart Da; and (2) a rule under CAA §111(d) that includes emission guidelines for GHGs from existing EGUs that would have been subject to 40 C.F.R. Part 60, subpart Da, if they were new sources.

On December 30, 2010, EPA announced a settlement agreement establishing a schedule that would require NSPS for fossil fuel power plants to be proposed by July 26, 2011, and a final rule to be promulgated by May 26, 2012.[26] After receiving several extensions,[27] on April 16, 2012, EPA promulgated its long-awaited proposed NSPS for EGUs.[28] The

9. American Petroleum Institute et al. v. EPA, No. 08-1277 (D.C. Cir. Dec. 23, 2010).
10. *Id.*
11. *Id.*
12. Andrew Childers, *EPA Seeks More Time to Propose Limits on Greenhouse Gases From Refineries*, 42 Env't Rep. (BNA) 2626 (Nov. 25, 2011).
13. U.S. EPA, *National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants*, 75 Fed. Reg. 54969 (Sept. 9, 2010).
14. Portland Cement Association v. EPA, 665 F.3d 177, 42 ELR 20358 (D.C. Cir. Dec. 9, 2011).
15. *Id.* at 193.
16. U.S. EPA, *Standards of Performance for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines*, 76 Fed. Reg. 37953 (June 28, 2011).
17. U.S. EPA, *New Source Performance Standards Review for Nitric Acid Plants*, 76 Fed. Reg. 63878 (Oct. 14, 2011).
18. *Id.* at 63880.
19. U.S. EPA, *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, 77 Fed. Reg. (2012).
20. U.S. EPA, *Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry, Fact Sheet*, *available at* http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf.
21. U.S. EPA, *Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units*, 71 Fed. Reg. 9866 (Feb. 27, 2006) [hereinafter the 2006 Final Rule].
22. The petitioners were: (1) the states of California, Connecticut, Delaware, Maine, New Mexico, New York, Oregon, Rhode Island, Vermont, and Washington, the commonwealth of Massachusetts, the District of Columbia, and the city of New York (collectively State Petitioners); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF) (collectively Environmental Petitioners).
23. State of New York et al. v. EPA, No. 06-1322 (D.C. Cir.).
24. 549 U.S. 497 (2007).
25. U.S. EPA, *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air*, 74 Fed. Reg. 66495 (Dec. 15, 2009).
26. U.S. EPA, *Proposed Settlement Agreement, Clean Air Act Citizen Suit*, 75 Fed. Reg. 82392 (Dec. 30, 2010).
27. *States, Activists Agree to Another EPA Delay on Power Plant GHG Rules*, 28 Envtl. Pol'y Alert (Inside EPA) 23:37 (Nov. 16, 2011).
28. U.S. EPA, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22392 (Apr. 13, 2012). A covered EGU is any fossil fuel-fired combustion unit that supplies more than one-third of its potential annual electric output and more than 25 MWe to any utility power distribution system for sale, with

proposed rule limits the CO_2 emissions from new electric power plants to 1,000 pounds of CO_2 per megawatt hour (MWh) of electricity output.[29] This standard is similar to the standards being imposed by several West Coast states.[30] This rulemaking would, for the first time, regulate GHGs under CAA §111. In addition, the CAA appears to provide that regulation of GHGs under CAA §111 triggers the applicability of the prevention of significant deterioration (PSD) program.[31] However, EPA is including a provision in its proposed regulation that limits the number of covered sources by confirming that the Tailoring Rule thresholds continue to apply to the PSD program.[32] The Tailoring Rule was promulgated on June 3, 2010, to create threshold GHG emission limits for triggering PSD and operating permit requirements that are substantially higher than the CAA's statutory requirement.[33] The rule was the subject of oral arguments in the D.C. Circuit on February 29, 2012, and the court's decision, when it is issued, is likely to be relevant to EPA's interpretation of the CAA in creating the proposed NSPS for EGUs.[34]

The proposed regulation specifies that it will not apply to existing EGUs whose emissions increase due to the installation of pollution controls for conventional pollutants, although EPA is required to promulgate NSPS for existing facilities in order to comply with the settlement agreement of December 10, 2010.[35] Nevertheless, EPA's failure to regulate existing sources appears to be a violation of CAA §111(d)(1), which requires the issuance of performance standards for existing sources whenever "a standard of performance under this section would apply if such existing source were a new source. . . ."[36]

EPA also exempts transitional sources that are sources with complete construction permits at the time of the proposal if they commence construction within 12 months. These sources differ considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1,320 MWs; they will burn different fuels: conventional coal, waste coal, or petcoke; and they will use different technologies: circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), supercritical pulverized coal, or sub-critical pulverized coal.[37] About 15 projects are included in this exemption, but many of these coal-fired plants may not be built, because financing is difficult to obtain, the costs of complying with new regulations applicable to conventional pollutants is high, and it may be cost-effective to shift to using natural gas.[38] Plants that are likely to be built are those that are recipients of U.S. Department of Energy (DOE) loan guarantees or grants for installing CCS.[39] Any natural gas-fired EGUs that have received PSD permits but have not commenced construction by the date of this proposal should be able to meet the NSPS.

Because some of the proposed sources may have incurred substantial sunk costs and may have progressed in their preconstruction planning to the point where they are poised to commence construction, EPA believes the 1,000 lbs. CO_2/MWh standard would not be appropriate to impose at this late date.[40] The proposed NSPS exempts approximately 15 proposed EGUs that have received preconstruction permits if they agree to install CCS and commence construction

certain exceptions. Covered EGUs include electric utility-generating units (boilers), stationary combined-cycle combustion turbines and their associated heat-recovery steam generator (HRSG), and duct burners; and IGCC units, including their combustion turbines and associated HRSG. However, this rule dos not regulate stationary simple-cycle combustion turbines. 77 Fed. Reg. at 22405.

29. N_2O (and to a lesser extent, methane (CH_4)) may be emitted from fossil fuel-fired EGUs, especially from coal-fired circulating fluidized bed (CFB) combustors and from units with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems installed for NO_x control. However, EPA did not propose N_2O or CH_4 emission limits or an equivalent CO_2 emission limit because of the lack of data for EGUs. The proposed rule provides for compliance to be calculated using the sum of the emissions for all operating hours and dividing that value by the sum of the electrical energy output and the useful thermal energy output, where applicable, for combined heat and power (CHP) EUGs, over a rolling 12-month period. Under this proposal, no averaging or emissions trading among affected sources is to be allowed. 77 Fed. Reg. at 22404.

EPA, in establishing the level of stringency for the proposed NSPS, has taken into account emissions during startup and shutdown periods, and the proposed NSPS would apply at all times, including during startups and shutdowns. 77 Fed. Reg. at 22408. The proposed NSPS also will apply during malfunctions, but EPA is proposing to allow an affirmative defense to civil penalties for exceeding emission limits caused by malfunctions if the defendant meets the requirements for an affirmative defense as found in 40 C.F.R. §60.10042. The source must prove that it has met all of the elements set forth in 40 C.F.R. §60.10001. (*See* 40 C.F.R. §22.24). The affirmative defense is available only where the event that caused the excess emissions meets the definition of malfunction found in 40 C.F.R. §60.2. The requirements aim to ensure that the malfunction is corrected, emissions are minimized, and future malfunctions are prevented. 77 Fed. Reg. at 22408.

30. In California, Senate Bill 1368, enacted in September 2006, established a standard of 1,100 lbs. CO_2/MWh for new and existing baseload generation owned by or under long-term contract to publicly owned utilities. In Washington, Substitute Senate Bill 6001, which became law in May 2007, imposed an emission standard of 1,100 lbs. CO_2/MWh for baseload electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. In Oregon, Senate Bill 101, which became law in July 2009, mandated that facilities generating baseload electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lbs. CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for baseload electricity with out-of-state facilities that do not meet that standard. Natural gas- and petroleum distillate-fired facilities that are primarily used to serve peak demand or to integrate energy from renewable resources are exempted from the performance standard. 77 Fed. Reg. at 22414. This could potentially create another loophole.
31. CAA §169(1), 42 U.S.C. §7479(1).
32. 77 Fed. Reg. at 22428.
33. U.S. EPA, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 75 Fed. Reg. 31514 (June 3, 2010).
34. Coalition for Responsible Regulation v. EPA, No. 10-1092 (D.C. Cir. May 7, 2010); American Chemistry Council v. EPA, No. 10-1167 (D.C. Cir. July 6, 2010).
35. 77 Fed. Reg. at 22400.
36. 42 U.S.C. §7411(d)(1).
37. 77 Fed. Reg. at 22421.
38. 77 Fed. Reg. at 22422. Since 2009, only one coal-fired power plant has been constructed in the United States. It is Southern Company's Kemper County Project, which uses CCS that is funded by DOE. 77 Fed. Reg. at 22422. *See generally* Arnold W. Reitze Jr., *Federal Regulation of Coal-Fired Electric Power Plants to Reduce Greenhouse Gas Emissions*, 32 Utah Envtl. L. Rev. (2012).
39. 77 Fed. Reg. at 22422. Six projects have plans to install CCS. They are: The Texas Clean Energy Project in Texas, the Trailblazer Project in Texas; the Taylorville Project in Illinois; the Good Spring facility in Pennsylvania; the Power County Advanced Energy Center in Idaho; and the Cash Creek Generation Plant in Kentucky. The remaining nine plants, which are not planning to use CCS, are: Limestone 3; White Stallion and Coletto Creek in Texas; Holcomb 2 in Kansas; James De Young and Wolverine in Michigan; Washington County in Georgia; Bonanza in Utah; and Two Elk in Wyoming. *Id.*
40. 77 Fed. Reg. at 22422, 22424.

within 12 months after the promulgation of the proposed rule CO_2 emissions from the NSPS.[41] This exemption appears to violate CAA §111(a)(2) that imposes NSPS on sources that commence construction after the publication of a proposed regulation.[42] The issue of when a regulation is applicable previously has been raised concerning the new source review program,[43] but it is not clear that EPA has the authority to modify the CAA's specific provision that applies an NSPS to sources constructed after the date of a proposed NSPS. However, even with an exemption from the NSPS, these transitional sources will be constrained in their emissions of CO_2 by other requirements of the CAA, including the requirements EPA eventually promulgates under CAA §111(d) that will apply to existing sources.[44]

The CAA defines a new source to include modified sources.[45] A modification is defined as a physical change or change in operation that increases the amount of any air pollutant emitted or that results in the emission of any air pollutant not previously emitted.[46] EPA's regulations define an NSPS "modification" as a physical or operational change that increases a source's maximum achievable hourly rate of emissions.[47] Pollution control projects are not considered to be modifications,[48] and EPA believes most of the projects that existing EGUs undertake in the foreseeable future will be pollution control projects that are exempt from the definition of modification.[49] Therefore, EPA did not include requirements applicable to modifications in its proposed NSPS.[50] The failure to include modified sources in the proposed regulation would appear to be a violation of CAA §111(a)(2).[51] The failure to include modifications in the NSPS will affect the many power plants expected to trigger the new source review requirements when they seek to comply with the Cross-State Air Pollution Rule (CSAPR) or the maximum achievable control technology (MACT) air toxics rule for coal-fired power plants.[52] EPA, by regulation, also imposes standards on reconstructed sources, which are sources that replace components to the extent that the capital costs of the new equipment or components exceed 50% of the cost of a completely new facility.[53] However, in the proposed GHG regulations, there is no provision for the regulation of reconstructed sources.[54] This would appear to be a violation of EPA's regulations.

An emission standard of 1,000 lbs. of CO_2 per MWh of electricity produced can be achieved by an electric power plant using NGCC technology. Such a facility uses the exhaust gas from the combustion turbine of approximately 1,000 degrees Fahrenheit to produce high-temperature steam that drives a separate turbine. Combustion turbines have peak performance efficiencies in the mid-30% range, and steam turbines can be used to produce electricity at an efficiency in the upper 30% range. The combined efficiency of a combined cycle plant using natural gas is approximately 59%.[55] Thus, NGCC facilities should be able to meet the NSPS without CCS.[56] EPA believes that almost all combined cycle gas turbines built in the United States in the past five years can meet the CO_2 standard.[57] EPA, however, exempts simple-cycle turbines, because they are used less often and are usually used to meet peak demand, not base or intermediate load requirements.[58] This exemption is another potential loophole, because it does not limit the hours of operation per year, and simple-cycle turbines could become a significant source of air pollutants if their use expands to serve as backup generation for renewable energy facilities.

To obtain an MWh of electricity and remain within EPA's NSPS mandate will require a coal-fired electric power plant to have a thermal efficiency of 69.37%.[59] This is well above the efficiency of even the most efficient coal-fired power plants.[60] For new coal-burning electric power plants,

41. EPA defines "commenced construction" at 40 C.F.R. §60.2.
42. 42 U.S.C. §7411(a)(2).
43. When EPA promulgated its regulatory interpretation concerning the pollutants covered by the CAA on April 2, 2010, it refined its interpretation of 40 C.F.R. §52.21(b)(50) and the parallel provision in 40 C.F.R. §51.166(b)(49) to establish that PSD permitting requirements apply to a newly regulated pollutant at the time a regulatory requirement to control emissions of that pollutant "takes effect" (rather than upon promulgation or the legal effective date of the regulation). U.S. EPA, *Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting Programs: Final Rule*, 75 Fed. Reg. 17003 (Apr. 2, 2010).This was the approach adopted in the rule for mobile sources that required compliance through vehicular certification before introducing any model-year 2012 into commerce. U.S. EPA & the U.S. Department of Transportation, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 75 Fed. Reg. 25523 (May 7, 2010). EPA concluded PSD program requirements and other stationary source requirements apply to GHGs upon the date that the tailpipe standards for the 2012 model-year light-duty vehicles (LDV) take effect, which EPA ruled is January 2, 2011.
44. 77 Fed. Reg. 22425.
45. CAA §111(a)(2), 42 U.S.C. §7411(a)(2).
46. CAA §111(a)(4), 42 U.S.C. §7411(a)(4).
47. 40 C.F.R. §60.14(a) & (b).
48. 40 C.F.R. §§60.2, 60.14(e)(5).
49. 77 Fed. Reg. at 22421.
50. 77 Fed. Reg. at 22400, 22421.
51. 42 U.S.C. §7411(a)(2).
52. Dawn Reeves, *Industry Warns EPA Cannot Exempt Modified Utilities From Climate NSPS*, 23 Clean Air Rep. (Inside EPA) 8:11 (Apr. 12, 2012).
53. 40 C.F.R. §60.15.
54. 77 Fed. Reg. at 22428.
55. This is based on 35% turbine efficiency plus .37 (efficiency of the steam cycle) times .65 (the percentage of heat remaining in the exhaust), which produces an overall efficiency of 59%.
56. Natural gas is approximately 90% CH_4 and 5% C_2H_6. One hundred pounds of gaseous fuel contains 67.75 pounds of carbon (85 x 12/16 + 5 x 24/30), which after combustion produce 248 pounds of CO_2 (67.75 x 44/12). Methane, the principal component of natural gas, has a British thermal unit (Btu) value that ranges from 23,879 to 21,520 per pound. Using a mid-range value of 22,700 Btu means that an MWh, which is equivalent to 3.413 million Btu, is the energy equivalent of 150 pounds of natural gas that when burned will produce 372 pounds of CO_2. A facility could combust 403 pounds of natural gas per MWh and stay within EPA's 1,000 pound per MWh limit for CO_2. Thus, a natural gas facility would need a thermal efficiency of about 37% to meet the proposed rule's requirement (150/403 = 37.2%).
57. 77 Fed. Reg. at 22396, 22398.
58. 77 Fed. Reg. at 22398.
59. 3.413/4.92.
60. An MWh is equal to 3.413 million Btu of energy. Babcock & Wilcox Company, Steam Its Generation and Use, app. 10-A10 (37th ed. 1960). One hundred pounds of a mid-range Ohio coal has a Btu value of 1.482 million Btu; it contains 82.2 pounds of carbon that will react with atmosphere oxygen to produce 301 pounds of CO_2. Babcock & Wilcox, at 2-9. Therefore, 332 pounds of coal is the maximum amount of coal that can be burned to produce one MWh of electricity and remain within EPA's CO_2 limit. This amount of coal has 4.92 million Btu.

conventional technology is pulverized coal boilers, because they can be used to generate electricity at the lowest cost of any fossil fuel-based technology.[61] A typical subcritical pulverized coal-fired power plant has an efficiency of about 37%.[62] State-of-the-art coal-fired plants, which utilize supercritical steam technology, without cogeneration, have an efficiency of about 42%, regardless of whether they are pulverized coal, pressurized fluidized bed combustion, or IGCC facilities.[63] Ultra-supercritical pulverized coal power plants that use two reheat cycles are estimated to achieve 48% efficiency.[64] Because coal-fired power plants cannot meet the 1,000 lbs. CO_2/MWh emission standard without CCS technology, EPA is proposing a program to encourage CCS. New coal-, coal refuse-, oil-, petroleum coke-fired, and IGCC EGUs could meet the NSPS by using CCS technology, although this will result in substantially higher construction costs than is incurred to build an NGCC facility and therefore is unlikely to occur.[65]

EPA expects the costs of utilizing CCS will decrease as technology improves and utilization increases. The Agency is proposing a 30-year averaging compliance option that would be available for coal, petroleum coke-fired sources, and IGCC plants that employ CCS.[66] For the first 10 years of operation, these sources would be required to comply with a 12-month annual average CO_2 emission limit based on the best demonstrated performance of a coal-fired facility without CCS.[67] EPA determined an emission limit of 1,800 lbs. CO_2/MWh (gross) is achievable by modern coal-fired facilities using supercritical steam and by IGCC facilities. EPA claims there are a dozen bituminous-fired and two subbituminous-fired EGUs that have demonstrated the proposed annual standard is achievable. The Agency also concluded that if coal-drying technology is utilized, the annual standard is achievable by EGUs burning a variety of coal types, including lignites.[68] The best performing subbituminous-fired EGU has maintained a 12-month emissions rate of 1,730 lbs. CO_2/MWh. A new EGU using a similar design could burn upgraded lignite and be in compliance with the proposed annual standard.[69]

No later than the 11th year from the effective date of the rule, the facility would be required to meet a reduced emission limit of no more than 600 lbs. CO_2/MWh (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year averaging period. Over the 30-year time period, the weighted average CO_2 emissions rate from the facility would be equivalent to the proposed standard of performance of 1,000 lb CO_2/MWh.[70] After 30 years, the source would be required to continue to meet the 12-month annual average 1,000 lbs. CO_2/MWh emission limit.[71] The 30-year averaging compliance option allows power companies to build a coal-fired power plant in the near term and install CCS at a later time when costs are expected to be lower.[72] The proposed rule requires sources to retain records to demonstrate compliance with the emission limits for at least 30 years following the date of initial startup of the affected EGU.[73] Trading among affected sources will be allowed for those using the 30-year averaging compliance option.[74] The 30-year averaging period will allow sources to benefit from the experience that will be gained from commercial-scale CCS demonstration projects funded by DOE.[75] Moreover, sources installing and operating CCS will have time to overcome startup problems and delays caused by the need for infrastructure development, e.g., pipeline construction for CO_2 transport.[76] It also allows time for sources to comply with state laws that have mandatory CCS requirements for new coal-fired electric power plants.[77] EPA's optimistic view of the potential use of CCS, however, seems premature. It is based primarily on six demonstration projects to be funded with $3.4 billion provided by the American Recovery and

61. G.T. Bielawski et al., *How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants*, U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium (Aug. 20-23, 2001), *available at* http://www.babcock.com/library/pdf/BR-1715.pdf.
62. Albert J. Bennett, *Progress of the Weston Unit 4 Supercritical Project in Wisconsin* 4 (Babcock & Wilcox Nov. 2006).
63. Bielawski et al., *supra* note 61. A plant can achieve 42% efficiency without a combined cycle or cogeneration through high temperature operation (1085° Fahrenheit (F)) using superheated steam at 3,775 pounds per square inch gage with a reheat to 1085° F. However, the exhaust steam from the high-pressure turbine subsequently can be utilized in a low-pressure turbine or it can be used as process steam, which is usually at temperatures below 400° F in order to increase efficiency. Bennett, *supra* note 62.
64. Bennett, *supra* note 62, at 4.
65. *See generally* Arnold W. Reitze Jr., *Federal Control of Geological Carbon Sequestration*, 41 ELR 10796 (Sept. 2011).
66. 77 Fed. Reg. at 22414.
67. 77 Fed. Reg. at 22417.
68. 77 Fed. Reg. at 22417, 22420.
69. 77 Fed. Reg. at 22420.
70. 77 Fed. Reg. at 22418.
71. *Id.*
72. 77 Fed. Reg. at 22407.
73. 77 Fed. Reg. at 22410. EPA is proposing that a CO_2 mass rate continuous emissions monitoring system (CEMS) and the associated automatic data acquisition and handling system must be installed and operated in accordance with the requirements in 40 C.F.R. Part 75. Owners/operators of a new unit are to conduct an initial performance test to demonstrate compliance with the CO_2 emission limits beginning in the calendar month following initial certification of the CO_2 and flow rate monitoring CEMS. Compliance with the applicable average CO_2 mass emissions rate (lbs./MWh) must be calculated as a 12-month rolling average, updated monthly, using the reported hourly CO_2 average concentration and flow rate values from the certified CEMS data collected for the previous month's process operating days, along with generation data tracked by the facility for the unit. EPA proposes that compliance with the emissions limit must be calculated by dividing the sum of the hourly CO_2 mass emissions values by the sum of the useful energy output produced for each calendar month period and that the 12-month rolling average must be updated as the average of the previous 12 months' calculations. 77 Fed. Reg. at 22409.
74. 77 Fed. Reg. at 22406.
75. 77 Fed. Reg. at 22414.
76. *Id.*
77. Several states have recently established requirements that new coal-fired EGUs must implement CCS, and a number of projects with CCS have been approved and/or are under construction. In May 2007, Montana's House Bill 25 enacted a CO_2 emissions performance standard for electric generating units in the state requiring new electric generating units primarily fueled by coal to use CCS for a minimum of 50% of the CO_2 produced by the facility. On January 12, 2009, Illinois Senate Bill 1987, the Clean Coal Portfolio Standard Law, was enacted that requires CCS for new power plants that use coal as their primary feedstock. From 2009-2015, new coal-fueled power plants must capture and store 50% of the carbon emissions; from 2016-2017, 70% must be captured and stored; and after 2017, 90% must be captured and stored. 77 Fed. Reg. at 22416.

Reinvestment Act.[78] None of these projects have progressed far enough to prove the technology will be cost-effective.[79] Indeed, there is every reason to believe the cost of CCS will make it very difficult to achieve its acceptance by utilities.[80] Moreover, the parasitic loss associated with CCS is estimated by DOE to be 30% for post-combustion capture.[81] This will make it more difficult (and perhaps impossible) to meet the 1,000 lbs. per MWh standard, because the standard applies to the power sent to the grid, but the CO_2 released from the power used internally in operating the facility has the effect of increasing the stringency of the standard. EPA's reliance on CCS is based on technology improvements that are to flow from DOE funding, but the CCS program is targeted for funding cuts that could hinder the development of this technology.[82]

EPA proposed NSPS creates a new subpart TTTT in 40 C.F.R. Part 60 that will regulate GHG emissions from all fossil fuel-fired EGUs.[83] This includes electric utility steam-generating units and IGCC units currently regulated in subpart Da and NGCC units currently regulated in subpart KKKK.[84] The proposed GHG rule does not affect the Part 60, Da, and KKKK regulations concerning conventional pollutants, nor does it affect the regulation of simple-cycle turbines under the KKKK category.[85]

If natural gas and coal-fueled units can be merged into a single category for the purposes of determining the appropriate technology for GHG control, could EPA take the next step and create a natural gas, coal, and wind power category with a zero emission rate for CO_2?[86] EPA justifies its combined NSPS categories on the basis that the industry generally is not building coal-fired power plants and is not expected to do so for the foreseeable future, because of lower electricity demand and competitive natural gas prices that is expected to lead utilities to rely on natural gas facilities to meet new demand for electricity.[87] On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant.[88] Moreover, state renewable portfolio standards (RPS), federal incentives for electric generation from renewable energy sources, and loan guarantees for new nuclear power plants discourage investments in coal-fired electric power plants. Thus, natural gas-fired power plants, renewable energy, and nuclear power are predicted to be the technologies used to meet new electricity demand over the coming years.[89] Whether industry decisions based on market conditions can be used to expand EPA's legal authority will eventually need to be decided by the courts.

EPA's NSPS must reflect "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."[90] After evaluating available technology, EPA usually creates a numerical emissions limit, based on the emission produced from using the best demonstrated technology (BDT). Generally, EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.

To determine BDT for EGUs, EPA evaluated natural gas-fired and coal-fired generation technologies, including supercritical and ultra-supercritical coal-fired boilers. Coal-fired units have CO_2 emissions of approximately 1,800 lbs./MWh and have the lowest costs of the conventional electricity-generating technologies.[91] EPA also considered new IGCC facilities, which can have similar CO_2 emissions but cost more than ultra-supercritical coal-fired units. Natural gas-fired boilers have CO_2 emissions of approximately 1,350 lbs./MWh, but NGCC is less expensive and more efficient, and thus the more widely used technology.[92] EPA believes NGCC is the best system of emission reduction, because it produces less pollution than coal, costs less than new coal-fired EGUs, and has fewer nonair quality health and environmental impacts.[93] EPA believes that, for economic reasons, new coal- or petcoke-fired EGUs will not be built in the foreseeable future, although the Agency is proposing that coal-fired plants may be constructed if CCS is used.[94] EPA defends the use of technology that is yet to be commercially viable based on the CAA's legislative history,[95] but its position appears to be a clear violation of the CAA, which requires the technology to be

78. Ari Natter, *Carbon Capture Demonstration Projects on Track to Meet 2016 Goal, DOE Says*, 43 Env't Rep. (BNA) 816 (Mar. 30, 2012).
79. Avery Fellow & Andrew Childers, *EPA Power Plant Rules Sharpen Debate Over Commercial Viability of Carbon Capture*, 43 Env't Rep. (BNA) 811 (Mar. 30, 2012).
80. *See generally* Reitze, *supra* note 65.
81. National Energy Technology Laboratory, *DOE/NETL Carbon Dioxide Capture and Storage Roadmap* 24 (Dec. 2010).
82. Dawn Reeves, *EPA Reliance on CCS in Utility NSPS Queried Following DOE Funding Cuts*, 23 Clean Air Rep. (Inside EPA) 9:11 (Apr. 26, 2012).
83. 77 Fed. Reg. at 22398.
84. EPA's rationale for combining coal-fired and natural gas-generating facilities for the purposes of controlling CO_2 emissions is based on the following reasoning: (1) fossil fuel-fired boilers, combined-cycle natural gas units, and IGCC units serve the same basic function, generating baseload or intermediate load power; (2) the proposed standards can be met by different types of units in the category (NGCC units or coal-fired units with CCS); and (3) it is consistent with industry trends of building new facilities using NGCC units or coal-fired units with CCS supported by federal funding. Moreover, EPA's analysis suggests that constructing a new unit that meets a limit of 1,000 lbs. CO_2/MWh instead of an advanced coal-fired unit without CCS would likely produce net social benefits. Separate source categories would be unlikely to generate substantial private cost savings, but would create the risk of significantly higher GHG emissions and other air pollutants from some new units, resulting in higher social costs. 77 Fed. Reg. at 22398.
85. *Id.*
86. EPA has previously combined one type of baseload and intermediate load combined-cycle unit (IGCC, previously covered under subpart GG) with Da units for the purposes of setting a standard [40 C.F.R. §60.41Da(b), Feb. 28, 2005].
87. 77 Fed. Reg. at 22399.
88. *Id.*
89. 77 Fed. Reg. at 22413.
90. CAA §111(a)(1), 42 U.S.C. §7411(a)(1).
91. 77 Fed. Reg. at 22417.
92. 77 Fed. Reg. at 22417-18.
93. 77 Fed. Reg. at 22418.
94. *Id.*
95. 77 Fed. Reg. at 22419.

"adequately demonstrated."[96] In addition, the D.C. Circuit has been explicit that in setting a CAA §111 standard of performance, EPA may make reasonable projections of what technology will be available to the regulated industry in the future.[97] EPA believes it may reasonably project the path of technological development, which supports treating CCS as a compliance alternative.[98]

By combining coal-fired and natural gas-fired units into one NSPS, EPA has essentially mandated that new EGUs use natural gas as the fuel, unless they are willing to gamble on the use of coal with the costly and commercially unproven CCS technology. The extent to which EPA can force an applicant to use a particular technology is not clear. The issue has been the subject of legal articles and court decisions involving the PSD program.[99] To obtain a PSD preconstruction permit, the CAA requires an analysis of alternatives and available control technology, and installation of the best available control technology (BACT).[100] For example, EPA's Environmental Appeals Board (EAB) ruled that the Agency could not require the use of low-sulfur coal at Peabody Energy's Prairie State proposed facility in Illinois because it would redefine the basic design of a mine-mouth facility that would burn high-sulfur Illinois coal.[101] Subsequently, in *Sierra Club v. EPA*,[102] the U.S. Court of Appeals for the Seventh Circuit ruled that EPA does not have to consider whether the applicant should use low-sulfur coal as a pollution control technology, because such a requirement would require significant modifications of the plant. These cases support the principle that a PSD program's BACT review cannot be used to require a redesign of a proposed facility. This issue has also arisen concerning whether IGCC technology can be mandated by the government as a pollution control technology within the meaning of BACT, or is IGCC a different electric power-generating technology that cannot be imposed by a permitting authority?[103]

It has been argued that IGCC is BACT, even though it is a different production process and is not an "end-of-stack" control. This position is supported by the language of CAA §169(3), which includes different production processes, fuel cleaning, and innovative fuel-combustion processes as BACT options.[104] EPA's position appears to be that §165(a)(2) requires alternative sources to be considered at an early stage in the permitting process, but once a technology is selected, §165(a)(4) requires air pollution control requirements to be based on controls that are appropriate for that technology. IGCC is considered by EPA to be a technology for generating electricity; it is not an air pollution control technology.[105] This position, however, is contrary to a 2009 case involving the Utah Division of Air Quality and the Utah Air Quality Board's approval order for the Sevier Power Company to construct a coal-fired, CFB power plant. The Sierra Club appealed to the Utah Supreme Court that held IGCC technology is a control technology that should be evaluated as part of a BACT review.[106] The Court concluded that requiring IGCC technology to be considered would not require Sevier Power to redefine the design of its proposed facility. Consideration of IGCC "does not compel its adoption; instead it only requires the Power Company to subject IGCC to the five-step, top down analysis used to determine the best available technology." The Court set aside the Division's decision and remanded the case. Among the requirements to be met by the Division is that it must conduct a BACT analysis that considers IGCC as an available control strategy.[107] These cases impose restrictions on EPA from substituting its choice of the appropriate technology for a project proposed by an applicant. If IGCC, which is a coal-fueled technology, may not by mandated, it is difficult to comprehend how EPA can essentially require natural gas to be used to fuel new fossil-fueled electric generation facilities. Moreover, under the definition of BACT found in the PSD program, emissions under BACT cannot exceed the emissions allowed under an NSPS.[108] EPA now appears to be attempting to avoid the limitations on defining BACT that have developed through case law by creating a proposed NSPS that will be the floor for defining BACT for EGUs.

In November 17, 2010, EPA issued PSD and Title V Permitting Guidance for Greenhouse Gases, and in March 2011, it replaced the guidance with a modified version.[109] The guidance continues to reflect the use of EPA's five-step, "top-down" BACT process, but addresses the process for determining BACT for GHGs. Because there is no "add-on" technology for controlling GHGs, the guidance stresses

96. CAA §111(a)(1), 42 U.S.C. §7411(a)(1).
97. Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 3 ELR 20642 (D.C. Cir. 1973).
98. 77 Fed. Reg. at 22419.
99. *See, e.g.*, Gregory B. Foote, *Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review*, 34 ELR 10642 (July 2004).
100. CAA §§165(a)(2) & (4), 42 U.S.C. §§7475(a)(2) & (4).
101. In re Prairie State Generating Co., PSD Appeal No. 05-05. 13 E.A.D. 1 (Aug. 24, 2006).
102. 499 F.3d 653, 37 ELR 20226 (7th Cir. 2007).
103. In addition, it is not clear that IGCC meets CAA §111's requirement that it is adequately demonstrated? In the IGCC process, coal of any quality is fed to a gasifier where it is partly oxidized by steam under pressure. By reducing oxygen in the gasifier, carbon in fuel is converted to gas that is a mixture of hydrogen (H_2) and carbon monoxide (CO) (syngas), which can be used to produce electricity. In 2006, there were more than 100 commercial IGCC plants worldwide, but only about a dozen generate electricity. *See* U.S. DOE, National Energy Technology Laboratory. The United States has four operating IGCC plants at full-scale operation. Only two are electric power-generating facilities, which use gasification technology to produce synthetic gas to fuel a gas turbine.
104. 42 U.S.C. §7479(3).
105. EPA's 1990 draft guidance indicated that it was not the Agency's general policy to redefine an applicant's design for a facility for purposes of considering what is available technology. *See* U.S. EPA, New Source Review Workshop Manual, Draft 1990, 88, In the Energy Policy Act, Pub. L. No. 109-58, §402 (2005). The U.S. Congress stated that it was taking no position as to whether IGCC was adequately demonstrated for purposes of CAA §111 or whether it is achievable for the purposes of CAA §§169 or 171. EPA's Stephen D. Page, however, in a letter of December 23, 2005, stated that IGCC is not BACT, because it involves the basic design of a proposed source. *See* Steven D. Page, EPA Letter on Use of Integrated Gasification Combined Cycle Technology as BACT, 36 Env't Rep. (BNA) 2666 (Dec. 23, 2005).
106. Utah Chapter of the Sierra Club v. Utah Air Quality Board, 226 P.3d 719 (2009).
107. *Id.* at 733.
108. CAA §169(3), 42 U.S.C. §7479(3).
109. *Available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

the importance of energy-efficiency improvements for new or modified sources in order to burn less fuel.[110] The guidance is ambiguous on what technologies must be considered.

> The permitting authority should take a "hard look" at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emission reductions without disrupting an applicant's basic business purpose for the proposed facility. In doing so, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.[111]

The guidance appears to give the permitting authority little useful assistance beyond the existing case law, although it does indicate that the safe course of action is to at least consider a range of options in the first step of the BACT analysis. The guidance does indicate that to require the use of natural gas for an applicant seeking to build a coal-fired power plant would, in most cases, be a fundamental redefinition of the project.[112] However, the guidance goes on to express approval for the permitting authority to exercise broad discretion in considering clean fuels or innovative technologies.[113] EPA subsequently discusses whether CCS technology is BACT. The Agency indicates that CCS should be included in Step 1 of the top-down BACT analysis, but it can be eliminated in step 2 if there is uncertainty that it will work in the situation undergoing review or if it is technically infeasible to use CCS. EPA believes CCS is a promising technology, but indicates that logistical hurdles and the lack of demonstrated availability will probably result in dismissing CCS after a BACT analysis. EPA's GHG guidance appears to be inconsistent with its proposed GHG regulation.

The United States has an estimated 239-year supply of coal at present levels of combustion.[114] However, much of this coal many never be burned in the United States, because its combustion results in emissions of conventional air pollutants that has led to increasingly stringent pollution control requirements. Relatively low prices for natural gas also discourage building new coal-fired power plants.[115] Moreover, the nascent development of GHG regulation is another reason for electric utilities to reduce their dependence on coal. These factors are encouraging a shift to using natural gas as the preferred fossil fuel to produce electric power.[116] However, existing coal-fired power plants are important sources of conventional pollutant emissions, as well as GHGs. The proposed NSPS for EGUs ignores the serious sources of air pollution to focus on plants that are unlikely to be constructed.

EPA analyzes the impacts of its proposed NSPS with surprising candor, which indicates the Agency does not expect significant changes in industry practices because of the proposed GHG NSPS for EGUs. "EPA believes that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of this proposal. . . ."[117] The Agency does not believe that "any new coal-fired EGUs without CCS will be built in the absence of this proposal."[118] "Accordingly, the EPA believes that this proposed rule is not likely to produce changes in emissions of greenhouse gases or other pollutants although it does encourage the current trend towards cleaner generation."[119] EPA also believes the "proposed rule is not anticipated to have a notable effect on the supply, distribution, or use of energy." Because EPA does not believe that new coal-fired EGUs without CCS will be built, "this proposed rule will have no notable compliance costs associated with it."[120] "EPA does not anticipate this proposed rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2020."[121] EPA goes on to say, "this rulemaking eliminates uncertainty about the status of coal and may well enhance the prospects for new coal-fired generation and the deployment of CCS, and thereby promote energy diversity."[122] The available evidence appears to contradict this statement.[123]

EPA concludes the preamble of its proposed NSPS rule with a request for comments that includes a list of issues for which EPA seeks information.[124] Thus, the final regulation may include significant changes. This regulation, if finalized in way that is consistent with the proposed regulation, should be expected to be subject to litigation by the coal and the fossil-fueled electric power industry, as well as a target for many members of the U.S. Congress. Challenges to the regulation can also be anticipated from environmental organizations. Challenges to the regulation will likely be based on EPA's proposal being arguably inconsistent with the CAA, as well as being inconsistent with EPA's prior regulations and case law. Thus, the battle will continue.

110. *Id.* at 21.
111. *Id.* at 26.
112. *Id.* at 27.
113. *Id.* at 28.
114. U.S. Energy Information Administration, *Coal Explained*, *at* http://205.254.135.7/energyexplained/index.cfm?page=coal_reserves (last visited Apr. 17, 2012).
115. Bobby McMahon, *EPA Air Rules, Gas Prices Further Weaken Prospects for New Coal Power*, 29 Envtl. Pol'y Alert 3:24 (Feb. 8, 2012).
116. *See generally* Arnold W. Reitze Jr., *Federal Regulation of Coal-Fired Electric Power Plants to Reduce Green House Gas Emissions*, 32 Utah Envtl. L. Rev. (pending 2012); Arnold W. Reitze Jr., *The Intersection of Climate Change and the Clean Air Act*, 43 Ariz. St. L.J. 901(2011); Arnold W. Reitze Jr., *Electric Power in a Carbon Constrained World*, 34 Wm. & Mary Envtl. L. & Pol'y Rev. 821 (2010); Arnold W. Reitze Jr., *Federal Control of Carbon Dioxide Emissions: What Are the Options?*, 36 B.C. Envtl. Aff. L. Rev. 1 (2009).
117. 77 Fed. Reg. at 22430.
118. *Id.*
119. *Id.*
120. *Id.*
121. *Id.*
122. *Id.*
123. *See generally* Arnold W. Reitze Jr., *Federal Control of Geological Carbon Sequestration,* 41 ELR 10796 (Sept. 2011).
124. 77 Fed. Reg. at 22431.