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

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The United States has an estimated 239-year supply of coal at present levels of combustion.[1] However, much of this coal many never be burned in the U.S. 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 discourages building new coal-fired power plants.[2] Moreover, the nascent development of greenhouse gas (GHG) regulation is another reason for electric utilities to reduce their wean their operations from dependence on coal. These factors are encouraging a shift to using natural gas to produce electric power.[3]

EPA reports that power plants accounted for 72 percent of the greenhouse gases (GHGs) emitted in the U.S. in 2010; 100 facilities reported emissions greater than 7 million metric tons of carbon dioxide equivalent (CO_{2e}), and 96 of these facilities were electric power plants.[4] To control CO_2 emissions, on April 13, 2012, EPA promulgated new source performance standards (NSPS) to limit greenhouse gas (GHG) emissions from electric generating units (EGUs).[5] The standards are based on the emissions produced by a natural gas combined cycle (NGCC) facility. EPA does not expect any coal-fired EGU will be able to meet this standard without using carbon capture and storage (CCS) technology to prevent much of the CO_2 emissions from being released

[1] U.S. Energy Information Administration, *Coal Explained*, available at http://205.254.135.7/energyexplained/index.cfm?page=coal_reserves (last visited Apr. 17, 2012.

[2] Bobby McMahon, *EPA Air Rules, Gas Prices Further Weaken Prospects for New Coal Power*, 29 ENVTL. POL'Y ALERT 3:24 (Feb. 8, 2012).

[3] *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 ARIZONA STATE L. J. 901(2011); Arnold W. Reitze, Jr., *Electric Power in a Carbon Constrained World*, 34 WILLIAM & MARY ENVTL. L. & POL'Y Rev. 821 (2010); Arnold W. Reitze, Jr., *Federal Control of Carbon Dioxide Emissions: What are the Options?*, 36 BOS. COL. ENVTL. AFF. L. REV. 1 (2009).

[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] U.S. Envtl. Protection Agency, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22,392 (Apr. 13, 2012).

to the atmosphere. This new rule essentially bans the use of coal as a fuel for new electric power plants unless the facility utilizes CCS for approximately 50% of its CO_2 emissions. This proposed NSPS is the subject of this article.

The Clean Air Act's (CAA) section 111 provides for emission standards to be established for new and modified sources in various industrial categories based on the capability of available technology, [6] after considering costs, non-air quality health and environmental impacts, and energy requirements.[7] There is no emission threshold for triggering the applicability of NSPS therefore almost all changes to existing facilities potentially can trigger NSPS applicability. However, the absence of cost effective CO_2 emission control technology hampers the use of this section.

The CAA directs the Administrator to review and, if appropriate, revise new source performance standards ("NSPS") at least every eight years.[8] Environmentalists seek to have GHG requirements included in revised NSPS, but industry advocates and their Congressional supporters resist these efforts. But, now that CO_2 is a regulated pollutant under the CAA,[9] 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 D.C. Circuit.[10] Subsequently EPA agreed to issue a proposed rule by December 10, 2011 and a final rule by November 10, 2012. [11] 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).[12] In November 2011, EPA announced it would miss the deadline and asked for additional time to comply.[13]

EPA promulgated New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants for the Portland Cement Industry, on September 9, 2010, without GHG standards. [14] 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

[6] CAA § 111, 42 U.S.C. § 7411.
[7] CAA § 111(a), 42 U.S.C. § 7411(a).
[8] CAA § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B).
[9] U.S. Envtl. Protection Agency, *Endangerment and Cause or Contributing Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66,496 (Dec. 15, 2009); U.S. Envtl. Protection Agency, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule,* 75 Fed. Reg. 25,524, 25,524 (May 7, 2010) (codified at 40 C.F.R. pts. 85, 86, 600).
[10] American Petroleum Institute *et al* v. EPA, No. 08-1277 (D.C. Cir.).
[11] *Id.*
[12] *Id.*
[13] Andrew Childers, *EPA Seeks More Time to Propose Limits on Greenhouse Gases from Refineries*, 42 Env't Rep. (BNA) 2626 (Nov. 25, 2011).
[14] U.S. Envtl. Protection Agency, *National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 75 Fed. Reg. 54,969 (Sept. 9, 2010).

rule.[15] 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.[16]

In June 2011 EPA promulgated a final rule amending the NSPS for stationary diesel engines, but the rule does not include GHG emission limits.[17] On October 14, 2011, EPA proposed a NSPS review for Nitric Acid Plants.[18] 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 NO_x, which also controls N_2O.[19]

On April 18, 2012, EPA released NSPS and national standards for hazardous air pollutants for the oil and natural gas sector.[20] 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 percent the volatile organic compounds (VOCs) that released from natural gas wells that are hydraulically fractured. The production and processing of natural gas is responsible for nearly 40 percent of U.S. methane emissions, which are GHGs that are twenty times as potent as CO_2.[21] 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 has been the effort to impose controls on electric generating units (EGUs). On February 27, 2006, EPA published a final rule that revised the standards of performance for criteria pollutant emissions from most EGUs.[22] The 2006 Final Rule did not establish standards of performance for GHG emissions. Two groups of petitioners filed petitions for judicial review of this rule in the D.C. Circuit contending, among other things, that the rule was required to have standards of performance established for GHG emissions from EGUs.[23] 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

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[15] Portland Cement Association v. EPA, 665 F.3d 177 (D.C. Cir. Dec. 9, 2011).
[16] *Id.* at 193 .
[17] U.S. Envtl. Protection Agency, *Standards of Performance for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines*, 76 Fed. Reg. 37,953 (June 28, 2011).
[18] U.S. Envtl. Protection Agency, *New Source Performance Standards Review for Nitric Acid Plants*, 76 Fed. Reg. 63,878 (Oct. 14, 2011).
[19] *Id.* at 63,880.
[20] U.S. Envtl. Protection Agency, *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, 77 Fed. Reg. (2012).
[21] U.S. Envtl. Protection Agency, *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 (last visited Apr. 18, 2012).
[22] U.S. Envtl. Protection Agency, *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) (the "2006 Final Rule").
[23] The petitioners were (1) the States of New York, California, Connecticut, Delaware, Maine, New Mexico, 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'').

D.C. Circuit[24] when the U.S Supreme Court decided *Massachusetts v. EPA.*[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, to avoid further litigation, the state and environmental petitioners and the EPA negotiated a proposed settlement agreement that set deadlines for EPA 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 C.F.R. part 60, subpart Da; and (2) a rule under CAA section 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] EPA received several extensions,[27] but sent the proposed NSPS to the Office of Management and Budget on November 7, 2011.[28] On March 27, 2012, EPA announced its long awaited proposed new source performance standards (NSPS) to control greenhouse gas (GHG) emissions from electric generating units (EGUs), and the rule was promulgated in the Federal Register on April 16, 2012.[29] The proposed rule limits the CO_2 emissions from new electric power plants greater than 25 megawatt electric (MWe), located in the continental U.S., to 1000 pounds of CO_2 per megawatt hour (MWhr) of electricity output.[30] This standard is similar to the standards being imposed by several West Coast states.[31] This rulemaking would, for the first

[24] State of New York *et al*, v. EPA, No. 06–1322 (D.C. Cir.)

[25] 549 U.S. 497 (2007).

[26] U.S. Envtl. Protection Agency, *Proposed Settlement Agreement, Clean Air Act Citizen Suit,* 75 Fed. Reg. 82,392 (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] *EPA Climate Rule Under OMB Review Limits GHG Controls to New Utilities,* 22 CLEAN AIR REP. (Inside EPA) 23:23 (Nov. 10, 2011).

[29] U.S. Envtl. Protection Agency, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units,* 77 Fed. Reg. 22,392 (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 MW net- electrical output (MWe) to any utility power distribution system for sale, with certain exceptions. Covered EGUs include electric utility steam 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, for purposes of this rule, covered EGUs do not include stationary simple cycle combustion turbines. 77 Fed. Reg. at 22,405.

[30] Nitrous oxide (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 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 22,404.

[31] In California Senate Bill 1368, enacted in September 2006, limits long-term investments in baseload generation by regulations that establish a standard of 1,100 lb CO_2/MWhr for new and existing baseload generation owned by, or under long-term contract to publicly owned utilities, In Washington Substitute Senate Bill 6001, which

time, regulate GHGs under CAA section 111. In addition, the CAA appears to provide that regulation of GHGs under CAA section 111 triggers the applicability of the PSD program.[32] However, EPA is including a provision in its proposed regulation that limits the number of covered sources by confirming the Tailoring Rule thresholds continue to apply to the PSD program. [33] 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.[34] 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.[35]

The proposed NSPS would apply at all times, including during startups and shutdowns. EPA in establishing the level of stringency for the proposed NSPS has taken into account emissions during startup and shutdown periods.[36] 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.[37]

EPA is required to promulgate NSPS for existing facilities in order to comply with the settlement agreement of December 10, 2010, but 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.[38] It also will not apply to sources with complete construction permits at the time of the proposal if they commence construction within twelve months. These sources differ considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1320 MWs; they will burn different fuels: conventional coal, waste coal, or petcoke; and they will use different technologies: circulating fluidized bed (CFB), integrated gasification

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became law in May 2007 established statewide GHG emissions reduction goals, and imposed an emission standard of 1,100 lb CO_2/MWhr 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 lb CO_2/MWhr, 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 22,414.

[32] CAA § 169(1), 42 U.S.C. § 7479(1).

[33] 77 Fed. Reg. at 22,428.

[34] U.S. Envtl. Protection Agency, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 75 Fed. Reg. 31,514 (June 3, 2010).

[35] Coalition for Responsible Regulation v. EPA, D.C. Cir. No. 10-1092; American Chemistry Council v. EPA, D.C. Cir. No. 10-1167.

[36] 77 Fed. Reg. at 22,408.

[37] A defendant must meet 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 are to ensure that steps are taken to correct the malfunction, to minimize emissions, and to prevent future malfunctions. If the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA § 113(see also 40 C.F.R. § 22.77). 77 Fed. Reg. at 22,408.

[38] 77 Fed. Reg. at 22,400.

combined cycle (IGCC), supercritical pulverized coal, or sub-critical pulverized coal.[39] 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.[40] Plants that are likely to be built are those that are recipients of Department of Energy loan guarantees or grants for installing CCS.[41] Because some of the 15 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 lb CO_2/MWh standard would not be appropriate to impose at this late date.[42] Even without an applicable standard of performance, 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 section 111(d) that will apply to existing sources.[43] Nevertheless, EPA's failure to regulate existing sources appears to be a violation of CAA section 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…." [44]

The proposed NSPS limit emissions based on the megawatt-hours (MWhr) of electricity produced. A MWhr is equal to 3.413 million Btu of energy.[45] One hundred pounds of a mid-range Ohio coal has a Btu value of 1.482 million Btu;[46] it contains 82.2 pounds of carbon[47] that will react with atmosphere oxygen to produce 301 pounds of CO_2.[48] Therefore 332 pounds of coal is the maximum amount of coal that can be burned to produce one MWhr of electricity and remain within EPA's CO_2 limit. This amount of coal has 4.92 million Btu. To obtain a MWhr 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 percent.[49] This is well above the efficiency of even the most efficient coal-fired power plants

For new coal-burning electric power plants conventional technology is pulverized coal boilers because they can be used to generate electricity at the lowest cost of any fossil fuel-based

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[39] 77 Fed. Reg. at 22,421.

[40] 77 Fed. Reg. at 22,422. *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).

[41] 77 Fed. Reg. at 22,422. 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.*

[42] 77 Fed. Reg. at 22,422, 22,424.

[43] 77 Fed. Reg. 22,425.

[44] 42 U.S.C. §7411(d)(1).

[45] BABCOCK & WILCOX COMPANY, STEAM ITS GENERATION AND USE, app. 10-A10 (37th ed. 1960).

[46] B & W, at 2-9, tbl. 11.

[47] B & W, at 2-9.

[48] Carbon has an atomic weight 0f 12.01; oxygen has an atomic weight of 15.9994 therefore the amount of carbon in CO_2 is approximately12/44.

[49] 3.413/4.92.

technology.[50] A typical subcritical pulverized coal-fired power plant has an efficiency of about 37%.[51] State-of-the-art coal-fired plants, which utilize super critical steam technology, without cogeneration, have an efficiency of about 42% regardless of whether they are pulverized coal, pressurized fluidized bed combustion, or integrated gasification combined cycle (IGCC) facilities.[52] Ultra-supercritical pulverized coal power plants that use two reheat cycles are estimated to achieve 48% efficiency.[53] Because coal-fired power plants cannot meet the 1000 lb CO_2/MWhr emission standard without CCS technology, EPA is proposing a long-term program to encourage CCS. New coal-, coal refuse-, oil-, petroleum coke-fired and IGCC EGUs should be able to meet the NSPS by using CCS technology, although this will result in substantially higher construction costs than is incurred to build a NGCC facility.[54]

Because EPA expects the costs of utilizing CCS will decrease as technology improves and utilization increases it is proposing a 30-year averaging compliance option that would be available for coal, petroleum coke-fired sources and IGCC plants that employ CCS.[55] For the first ten 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.[56] EPA has determined that an emission limit that is achievable by modern coal-fired facilities using supercritical steam and by IGCC facilities is 1,800 lb CO_2/MWhr (gross). EPA says 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.[57] The best performing subbituminous-fired EGU has maintained a 12-month emissions rate of 1,730 lb CO_2/MWhr. A new EGU using a similar design could burn upgraded lignite and be in compliance with the proposed annual standard.[58]

No later than the eleventh year from the effective date of the rule, the facility would be required to meet a reduced emission limit of no more than 600 lb CO_2/MWhr (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

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[50] G.T. Bielawski, J.B. Rogan, D.K. McDonald, *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 (last visited Mar. 30, 2012).

[51] Albert J. Bennett, *Progress of the Weston Unit 4 Supercritical Project in Wisconsin* 4 (Babcock & Wilcox (Nov. 2006).

[52] Bielawski, *supra* note 50. A plant can achieve 42 percent efficiency without a combined cycle or cogeneration through high temperature operation (1085^0 F) using superheated steam at 3775 pounds per square inch gage with a reheat to 1085^0 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 degrees Fahrenheit in order to increase efficiency. Bennett, *supra* note 51.

[53] Bennett, *supra* note 51, at 4.

[54] *See generally,* Arnold W. Reitze, Jr., *Federal Control of Geological Carbon Sequestration*, 41 ENVTL. L. REP. (ELI) 10796 (Sept. 2011).

[55] 77 Fed. Reg. at 22,414.

[56] 77 Fed. Reg. at 22,417.

[57] 77 Fed. Reg. 22,417, 22,420.

[58] 77 Fed. Reg. at 22, 420.

equivalent to the proposed standard of performance of 1,000 lb CO_2/MWhr.[59] After thirty years, the source would be required to continue to meet the 12-month annual average 1,000 lb CO_2/MWhr emission limit. [60]

EPA supports a 30-year averaging compliance option because it provides power companies with the option of building a coal-fired power plant in the near term and installing CCS at a later time when costs are expected to be lower.[61] 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.[62] Trading among affected sources will be allowed for those using the 30-year averaging compliance option.[63] 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. [64] 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).[65] It also allows time for sources to comply with state laws that have mandatory CCS requirements for new coal-fired electric power plants.[66] 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 Reinvestment Act.[67] None of these projects have progressed far enough to prove the technology will be cost effective. [68] Indeed, there is every reason to believe the cost of CCS, including the substantial parasitic energy loss, will make it very difficult to achieve its acceptance by utilities. [69]

An electric power plant using natural gas combined cycle (NGCC) technology will be able to meet the proposed emission standard. Such a facility uses the exhaust gas temperature from the combustion turbine of approximately 1000 degrees F is used to produce high temperature steam that drives a separate turbine. Combustion turbines have peak performance

[59] 77 Fed. Reg. 22, 418.
[60] 77 Fed. Reg. at 22,418.
[61] 77 Fed. Reg. at 22,407.
[62] 77 Fed. Reg. at 22,410.
[63] 77 Fed. Reg. at 22,406.
[64] 77 Fed. Reg. at 22,414.
[65] 77 Fed. Reg. at 22,414.
[66] 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 percent 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 22,416.
[67] Ari Natter, *Carbon Capture Demonstration Projects On Track to Meet 2016 Goal, DOE Says*, 43 Env't Rep. (BNA) 816 (Mar. 30, 2012).
[68] 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).
[69] *See generally*, Arnold W. Reitze, Jr. *Federal Control of Geological Carbon Sequestration*, *supra* note 54.

efficiencies in the mid-thirty percent range, and steam turbines can be used to produce electricity at an efficiency in the upper thirty percent range. The combined efficiency of a combined cycle plant using natural gas is approximately fifty-nine percent.[70] The 30-year averaging compliance option is not available NGCC units, as they should be able to meet the proposed performance with no need for CCS technology.[71]

Natural gas is approximately 90% CH_4 and 5% C_2H_6.[72] One hundred pounds of gaseous fuel contains 67.75 pounds of carbon,[73] which after combustion produce 248 pounds of CO_2.[74] Methane, the principal component of natural gas, has a Btu value that ranges from 23,879 to 21,520 per pound.[75] Using a mid-range value of 22,700 Btu means that a MWhr, which is equivalent to 3.413 million Btu,[76]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 MWhr and stay within EPA's 1000 pound per MWhr limit for CO_2. Thus a natural gas facility would need a thermal efficiency of about 37 percent to meet the proposed rule's requirement.[77] EPA believes that almost all combined cycle gas turbines built in the U.S. in the past five years can meet the CO_2 standard.[78]

EPA is proposing to create a new subpart TTTT in 40 C.F.R. Part 60 that will regulate GHG emissions from all fossil fuel-fired EGUs. [79] This includes electric utility steam generating units and IGCC units currently regulated in subpart Da and combined cycle units currently regulated in subpart KKKK.[80] 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.[81]

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[70] 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%.

[71] 77 Fed. Reg. at 22,398.

[72] B & W, *supra* note 45, at 4-8.

[73] 85 x 12/16 + 5 x 24/30.

[74] 67.75 x 44/12.

[75] B & W, *supra* note 45, at 4-2, tbl.1.

[76] B & W, *supra* note 45, at app. 10-A10

[77] 150/403 = 37.2%.

[78] 77 Fed. Reg. at 22,396, 22,398.

[79] 77 Fed. Reg. at 22,398.

[80] EPA's rational 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 natural gas combined cycle 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 lb 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 22,398.

[81] 77 Fed. Reg. 22,398.

If natural gas and coal 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?[82] 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.[83] 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.[84] 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 technology used to meet new electricity demand over the coming years.[85] 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.

The CAA's § 111(a)(2) provides that NSPS are applicable on the date proposed regulations are published.[86] The issue of when a regulation is applicable has also previously been raised concerning the new source review program,[87] but it is not clear that EPA has the authority to modify the CAA's specific provision that applies a NSPS beginning with the date of the proposed regulation. EPA's proposed NSPS exempts CO_2 emissions from the NSPS requirements for the approximately 15 proposed EGUs that have received preconstruction permits if they agree to install CCS and commence construction within twelve months after the promulgation of the proposed rule.[88] This appears to be inconsistent with the CAA.

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

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[82] 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].

[83] 77 Fed. Reg. at 22,399.

[84] 77 Fed. Reg. at 22,399.

[85] 77 Fed. Reg. at 22,413.

[86] CAA § 111(a)(2), 42 U.S.C. § 7411(a)(2).

[87] 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. Envtl. Protection Agency, *Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting Programs: Final Rule*, 75 Fed. Reg. 17003 (April 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. Envtl. Protection Agency & the U.S. Department of Transportation, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 75 Fed. Reg. 25,523 (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.

[88] EPA defines "commenced construction" at 40 C.F.R. § 60.2.

achieving such reduction and any other nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[89] After evaluating available technology, EPA usually creates a numerical emissions limit, based on the technology known as the best demonstrated technology (BDT). Generally, the 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. These boilers have CO_2 emissions of approximately 1,800 lb/MWh and have the lowest costs of the conventional coal-based electricity technologies.[90] 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 lb/MWh, but NGCC is less expensive, more efficient and for that reason it is the more widely used technology.[91] 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.[92] EPA believes that for economic reasons, new coal- or pet coke-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.[93] EPA defends the use of technology that is yet to be commercially viable based on the CAA's legislative history.[94] In addition, the D.C. Circuit has been explicit that in setting a CAA section 111 standard of performance, the EPA may make reasonable projections of what technology will be available to the regulated industry in the future.[95] EPA believes it may reasonably project the path of technological development, which supports treating CCS as a compliance alternative.[96]

The extent to which EPA can force an applicant to use a particular technology is not clear. The issue has been the subject of the legal articles and court decisions concerning the PSD program.[97] 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).[98] Courts have held that the BACT requirement cannot be used to force an applicant to redesign a proposed facility. On August 24, 2006, EPA's EAB ruled the Agency could not require the use of low sulfur coal at Peabody Energy's Prairie State proposed facility in Illinois

[89] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).
[90] 77 Fed. Reg. at 22,417.
[91] 77 Fed. Reg. at 22,417—22,418.
[92] 77 Fed. Reg. at 22,418.
[93] 77 Fed. Reg. at 22,418.
[94] 77 Fed. Reg. at 22,419.
[95] Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375 (D.C. Cir.1973).
[96] 77 Fed. Reg. at 22,419.
[97] *See e.g.* Gregory B. Foote, *Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review*, 34 ENVTL. L. REP. (ELI) 10642, (July 2004).
[98] CAA §§165(a)(2) & (4), 42 U.S.C. §§ 7475(a)(2) & (4).

because it would redefine the basic design of the facility, which was planned as a mine-mouth facility that would burn high-sulfur Illinois coal.[99] Subsequently, in *Sierra Club v. EPA*, 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. [100] 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 BACT or is IGCC a different electric power generating technology that cannot be imposed by a permitting authority? In addition, it is not clear that IGCC meets CAA section 111's requirement that it is adequately demonstrated?[101]

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.[102] 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.[103] In the August 6, 2005 Energy Policy Act, 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.[104] 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. EPA's position was that section 165(a)(2) requires alternative sources to be considered at an early stage in the permitting process, but once a technology is selected section 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]

In Texas a proposed 800 megawatt pulverized coal power plant was the subject of a challenge by environmentalists because it did not plan to use IGCC technology. On January 29, 2009, a Texas state appeals court ruled in *Blue Skies Alliance, et al. v. Texas Environmental Quality Commission* that IGCC is not a viable control technology for a conventional pulverized

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[99] In Re: Prairie State Generating Company, PSD Appeal No. 05-05. 13 E.A.D. 1(Aug. 24, 2006)
[100] 499 F.3d 653 (7th Cir. 2007).
[101] 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. Dept. of Energy, 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.
[102] 42 U.S.C. § 7479(3).
[103] United States Envtl. Protection Agency, New Source Review Workshop Manual, Draft 1990, 88 <http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf > (last visited Apr. 23, 2012).
[104] Pub. L. No. 109-58, § 402 (2005).
[105] Steven D. Page, EPA Letter on Use of Integrated Gasification Combined Cycle Technology as BACT, 36 Env't Rep. (BNA) 2666 (Dec. 23, 2005); *see also* Steven D. Cook, *EPA Official Reports Gasification* as *Standard For New Coal-Fired Electric Power Plants,* 36 Env't REP. (BNA) 2625 (Dec. 23, 2005).

coal plant, and held a BACT analysis does not require an alternative to be considered that would require a redesign of the proposed facility. [106]

The Utah Division of Air Quality and the Utah Air Quality Board, in 2004, granted Sevier Power Company an approval order to construct a coal-fired, circulating fluidized bed power plant. The Sierra Club appealed to the Utah Supreme Court.[107] The most important part of the decision was the Court's finding that IGCC technology is a control technology that should be evaluated as part of a BACT review. 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.[108]

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, the IGCC cases also have the potential to be useful in answering the question of whether CCS is an available technology. Under the definition of BACT found in the PSD program, emissions under BACT cannot exceed the emissions allowed under a NSPS.[109] EPA now appears to be attempting to avoid the limitations on defining what is BACT that has 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.[110] 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 the importance of energy efficiency improvements for new or modified sources in order to burn less fuel.[111] 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."[112] The

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[106] *Desert Rock Suit Tees Up Long-Running Dispute Over IGCC As BACT,* XX CLEAN AIR REP. (Inside EPA) 5:30 (Mar. 5, 2009).
[107] Utah Chapter of the Sierra Club v. Utah Air Quality Board , 209 UT 76, 226 P. 3d 719 (2009).
[108] Utah Chapter of the Sierra Club v. Utah Air Quality Board, 226 P.3d 719, 733 (2009).
[109] CAA § 169(3), 42 U.S.C. § 7479(3).
[110] Available at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (last visited Apr. 23, 2012).
[111] Guidance at 21.
[112] Guidance at 26.

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, inmost cases, be a fundamental redefinition of the project.[113] However, the guidance goes on to express approval for the permitting authority to exercise broad discretion in considering clean fuels or innovative technologies.[114] 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 CAA defines a new source to include modified sources.[115] 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.[116] EPA's regulations define a NSPS "modification" as a physical or operational change that increases a source's maximum achievable hourly rate of emissions.[117] Pollution control projects are not considered to be modifications,[118] 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.[119] Therefore, EPA did not include requirements applicable to modifications in its proposed NSPS.[120] The failure to include modified sources in the proposed regulation would appear to be a violation of CAA section 111(a)(2).[121] EPA by regulation 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 percent of the cost of a completely new facility.[122] However, in the proposed GHG regulations there is no provision for the regulation of reconstructed sources.[123] This would appear to be a violation of EPA's regulations.

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 CFR Part 75.[124] Owners/operators of a new unit are to conduct an initial performance test to demonstrate compliance with the CO_2

[113] Guidance at 27.
[114] Guidance at 28.
[115] CAA § 111(a)(2), 42 U..S.C. § 7411(a)(2).
[116] CAA 111(a)(4), 42 U.S.C. § 7411(a)(4).
[117] 40 C.F.R. § 60.14(a) & (b).
[118] 40 C.F.R. §§ 60.2, 60.14(e)(5).
[119] 77 Fed. Reg. at 22,421.
[120] 77 Fed. Reg. at 22,400, 22,421.
[121] 42 U.S.C. § 7411(a)(2).
[122] 40 C.F.R. § 60.15.
[123] 77 Fed. Reg. at 22,428.
[124] 77 Fed. Reg. at 22,409.

emission limits beginning in the calendar month following initial certification of the CO_2 and flow rate monitoring CEMS.[125] Compliance with the applicable average CO_2 mass emissions rate (lb/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.[126] 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.[127]

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…" [128] The Agency does not believe that "any new coal-fired EGUs without CCS will be built in the absence of this proposal." [129] "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."[130] EPA also believes the "proposed rule is not anticipated to have a notable effect on the supply, distribution, or use of energy." EPA does not believe that "any new coal-fired EGUs without CCS will be built in the absence of this proposal." "EPA believes this proposed rule will have no notable compliance costs associated with it."[131] "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."[132]

EPA does not expect that the power industry will incur compliance costs as a result of this proposal and it does not expect any notable CO_2 emission changes resulting from the rule.[133] "Therefore, there are no direct monetized climate benefits in terms of CO_2 emission reductions associated with this rulemaking." [134] 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."[135] It would be nice if this statement was correct.

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[125] *Id.*
[126] *Id.*
[127] 77 Fed. Reg. at 22,409.
[128] 77 Fed. Reg. at 22,430.
[129] *Id.*
[130] *Id.*
[131] *Id.*
[132] *Id.*
[133] *Id.*
[134] *Id.*
[135] *Id.*

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.[136] 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 Congress. Challenges to the regulation can also be anticipated from environmental organizations that can be expected to seek more control of existing plants that are modified. 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.

[136] 77 Fed. Reg. at 22,431.