Unions for Jobs & Environmental Progress

ujep4jobs@gmail.com
www.ujep4jobs.org

Jim Hunter, IBEW
President, UJEP
hunter@ibew.org

John Risch, SMART - TD
Vice President, UJEP
jrisch@smart-union.org

U.S. Environmental Protection Agency
1201 Pennsylvania Avenue, N.W.
Washington, DC 20460

April 24, 2014

By E-mail Transmission
A-and-R-Docket@epamail.epa.gov

Re: Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units
U.S. EPA Docket EPA-HQ-OAR-2013-0495

Ladies and gentlemen:

These comments on the above-proposed rule are submitted on behalf of Unions for Jobs and Environmental Progress (UJEP), an independent association of national and international labor unions identified below. UJEP's member unions represent more than 3.2 million workers in electric power, rail transportation, coal mining, construction, and other energy-related industries. UJEP members' jobs and economic wellbeing will be vitally affected by U.S. EPA's decisions on New Source Performance Standards (NSPS) for greenhouse gas (GHG) emissions for new electric utility sources.

UJEP is an independent association of labor unions involved in energy production and use, transportation, engineering, and construction. Our members are: International Association of Bridge, Structural, Ornamental and Reinforcing Iron Workers Union; International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers; International Brotherhood of Electrical Workers; International Brotherhood of Teamsters; SMART Transportation Division; Transportation • Communications International Union; United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada; United Mine Workers of America; and Utility Workers Union of America.

Background

UJEP member unions participate in both the domestic and international climate change processes. UJEP member unions are accredited Non-Governmental Organization (NGO) representatives in the United Nations Framework Convention on Climate Change (FCCC) process. UJEP members have engaged the climate change process domestically through assisting in the design of national climate change legislation, focusing particularly on emissions reduction targets and timetables, international trade adjustment issues, and mechanisms to promote the commercial development of advanced coal generation with carbon capture and storage (CCS).

In 2007-08, UJEP members helped U.S. EPA's Work Group on Advanced Coal Technology (ACT) to reach a unanimous recommendation calling for prompt federal legislative development of a non-budget funding mechanism for early commercial demonstration of CCS technologies.[1] UJEP members subsequently helped to design legislation implementing the ACT Work Group's consensus recommendation for funding early demonstration of CCS technologies.

The Boucher-Rahall bill (HR 6258, 110th Cong, 2d Sess.) incorporated the basic design elements of the ACT recommendations by the creation of a "wires charge" to provide an annual funding stream of $1 billion for the early demonstration of CCS technologies. This bill was incorporated as Section 114 of the Waxman-Markey climate bill passed by the House of Representatives in June 2009 (HR 2454, 111th Cong., 1st Sess.) It also was included in modified form in the proposed Kerry-Lieberman American Power Act (111th Cong., 2d Sess.)

To date, Congress has not authorized programs to accelerate the large-scale commercial demonstration of CCS technologies beyond the relatively modest programs funded through the Office of Fossil Energy at the U.S. Department of Energy.

As a consequence of Congress's inability to provide support mechanisms to advance the large-scale commercial demonstration of CCS technologies, and the absence of successful deployments of CCS at utility scale, we are firmly persuaded that CCS is not yet an "adequately demonstrated" technology for purposes of establishing the NSPS proposed in this rule.

---

[1] U.S. EPA Clean Air Act Advisory Committee, "Final Report of the Advanced Coal Technology Work Group," (January 29, 2008).

Summary of Comments

UJEP recommends that EPA re-propose this rule on a basis consistent with the agency's 2010 Best Available Control Technology (BACT) Guidance for GHG emissions from stationary sources. The NSPS for coal-based generation should establish achievable emission rate limitations without CCS for supercritical, ultra-supercritical and IGCC units. CCS can be considered as a potential control option through the top-down BACT review process on a case-by-case basis. A new generation of advanced coal plants is needed to serve as the platform for the eventual deployment of lower-cost, second-generation CCS technologies.

We agree with EPA's decision to provide separate emission standards for coal and natural gas combined-cycle units. The agency's previous proposal to combine these two sources into one category (77 FR 22392) failed to recognize the fundamental technical, economic, and engineering differences between these two very different methods of electrical generation.

Our principal objection to the proposed rule is that it effectively precludes the construction of new, state-of-the art coal generation facilities that otherwise could be permitted under the agency's BACT Guidance for new fossil-fueled sources. The rule paralyzes new coal plant construction because owners must commit in the permitting process to utilize CCS technology at partial or full levels. The absence of CCS requirements for new natural gas combined-cycle units will direct virtually all future investments in baseload generation to natural gas, while eliminating coal as a competitive price constraint on natural gas.

UJEP members are concerned that the proposed rule, in combination with other existing and expected environmental regulations in the power sector,[2] could lead to a situation in which natural gas becomes the dominant source of baseload and peak power in many areas of the country. This move away from a multi-fuel generation system to what would effectively be a single-fuel system in much of the U.S. could have serious, negative repercussions for energy security and electric reliability. For example, without sufficient coal or other generation options, sustained cold weather events—such as those the country experienced this winter—

[2] These regulations include, but are not limited to, rules regulating air toxic emissions, wastewater discharges, cooling water intake, and coal ash storage at fossil-fueled power plants, as well as EPA's forthcoming greenhouse regulations for modified and existing sources. The proliferation of competitive electricity markets and the continued stalemate over nuclear waste storage are also contributing to the transition to a single-fuel generation system.

could lead to natural gas supply disruptions that could compromise the electric system. Similarly, the growth in international trade in natural gas that is being facilitated by construction of liquefied natural gas terminals in major exporting countries (including the U.S.) could expose the power industry to significant price shocks or supply disruptions like those America has experienced in the past due to its over-reliance on petroleum fuel for transportation.

CCS is neither commercially demonstrated at utility scale nor economically viable in the absence of government subsidies or other mechanisms for offsetting the substantial incremental costs of CCS technology.[3] Under section 111, only systems that have been "adequately demonstrated" may be considered in setting an NSPS.[4] In order for CCS to be "adequately demonstrated," there must, at a minimum, be some evidence—in the form of actual examples—that could reasonably lead EPA to conclude that the selected system is reliable, efficient, and can be implemented at the regulated source. The Court of Appeals for the D.C. Circuit has made clear that where such examples are not available, "EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture."[5] As discussed below, EPA may not rely on unbuilt facilities, non-EGU facilities in other industrial sectors, or small pilot-scale facilities to make the required showing. Because these facilities have never been required to operate under the constraints of a typical utility duty cycle (e.g., continuous 24-hour operation, availability to respond to system emergencies, limited ability to go offline for repairs, etc.), their performance is not representative of that of the commercial-scale EGUs that EPA proposes to regulate under the proposed rule. In addition, we note that EPA appears to be prohibited by section 48A of the Internal Revenue Code from relying on technologies used or emission levels achieved at most of these facilities when setting the NSPS for EGUs.[6]

---

[3] *See*, Testimony of Dr. Julio Friedmann, U.S. Department of Energy, before the U.S. House Committee on Energy and Commerce, Subcommittee on Oversight and Investigations, February 12, 2014.

[4] 42 U.S.C. § 7411(a)(1).

[5] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (citing Nat'l Asphalt Pavement Ass'n v. Train, 539 F.2d 775, 787 (D.C. Cir. 1976)).

[6] Internal Revenue Code section 48A(g) prohibits EPA from considering the "use of technology" or "achievement of any emission reduction by the demonstration of any technology or performance level" at facilities for which the section 48A tax credit has been allowed. *See* 26 U.S.C. § 48A(g). As EPA notes in its Technical Support Document on "Effect of EPAct05 on

EPA's Regulatory Impact Analysis for the proposed rule shows that CCS raises the cost of electricity from a new supercritical unit by 36% to 81%, depending on whether it uses partial or full CCS.[7] Costs for plants that have access to EOR markets for CO2 sales are 17% to 42% higher than EPA's base case. We strongly disagree with EPA's position that such cost increases are "reasonable" under applicable case law precedent such as *Portland Cement*.[8]

We disagree with EPA's view that potential EOR applications represent a viable path for capturing and sequestering CO2 emissions from utility-scale power plants. Our concerns in this regard are three-fold: 1) EOR opportunities are inherently limited to petroleum-producing regions, and do not extend to the full range of states to which the NSPS apply; 2) EPA has not addressed the possibility that EOR or carbon sequestration facility operators—who may be third parties—may be unable to accept CO2 from power plants due to operational constraints, even when those plants would be required to continue producing power[9]; and 3) the agency's assumed $20 to $40/ton revenue stream from EOR sales is inadequate to offset the full costs of CO2 capture, compression and transport – as recognized by proposed (and pending) federal legislation such as S. 3581 (112th Cong., 2d Sess.)

BSER for New Fossil Fuel-fired Boilers and IGCCs," the Kemper, HECA, and TCEP facilities have all been allocated a section 48A investment credit. *See* EPA, Technical Support Document, Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs, at 12 (January 8, 2014). Therefore, even if these facilities were constructed, EPA would not be able to rely on test data or technology used at these facilities in setting performance standards for EGUs under the Proposed Rule. Other provisions of the Energy Policy Act of 2005 may also prohibit EPA from relying on these projects. *See, e.g.,* Energy Policy Act of 2005, P.L. 109-58, § 402(i) (Aug. 8, 2005) (codified at 42 U.S.C. § 15962(i)) ("No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be . . . adequately demonstrated for purposes of section 111 of the Clean Air Act . . . .").

[7] EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (2013) at Fig. 5-7.

[8] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973).

[9] EGUs must comply with reliability constraints, which often entail continuing to run even when pollution control equipment is not functioning or available. EPA's reliance on a technology that requires EGU owners to ensure the cooperation of a third party EOR or sequestration operator in order to meet the NSPS could thus require EGU owners to oversize their systems or obtain costly insurance against possible disruptions in sequestration operations—a factor that EPA has not adequately considered.

Previous EPA NSPS rules requiring the application of relatively new emission control technologies, such as flue gas desulfurization (FGD) for SO2 control, were promulgated only after FGD technologies had been extensively tested and successfully applied at commercial-scale electric generating units. The initial 1971 NSPS required coal-based units to meet an emission rate limit of 1.2 lbs. SO2/MMBTU, which could be achieved by FGD or by low-sulfur coals without add-on controls.[10] At that time, there were no commercial-scale electric generating units in operation employing FGD technology.

The 1979 Revised NSPS for SO2 control required a sliding-scale 70%-90% reduction of SO2 emissions with a maximum emission rate of 1.2 lbs. SO2/MMBTU,[11] effectively mandating the use of FGD. As of November 1978, 46 operating commercial-scale electric generating units were equipped with FGD in the U.S., with another 43 units under construction.[12] Dozens of plants constructed prior to 1979, and subject only to the 1.2 lb. SO2/MMBTU limitation of the 1971 NSPS, had elected to install and operate FGD technologies. This extensive operating experience with FGD technologies, together with large projected increases in SO2 emissions under prior NSPS and the need to prevent air quality deterioration, provided the legislative basis for the "percentage reduction" clause added to Section 111 by the 1977 Clean Air Act Amendments.[13]

The same measured approach to the application of CCS should apply in this rulemaking. NSPS set a floor – not a ceiling - for emission rate limitations. The NSPS floor is subject to potentially more stringent requirements under the case-by-case BACT reviews in the New Source Review program. EPA's 2010 BACT Guidance recommended that CCS be "listed" at the initial stage of the BACT review process as an "available" option for reducing GHG emissions from major new and modified utility and industrial sources, but did not mandate its incorporation in PSD construction permits.

---

[10] 36 FR 24876 (December 23, 1971).

[11] 44 FR 33580 (June 11, 1979).

[12] National Research Council, Committee on Evaluation of Sulfur Oxides Control Technology, *Flue Gas Desulfurization* (1980) at Table 4.3.

[13] *See id.*, at 13-17.

The agency's current BACT Guidance reflected EPA's support for the findings of the 2010 Interagency CCS Task Force. For EPA now to propose CCS as a mandatory component of NSPS for GHG emissions from coal-based electric generation sources constitutes both a rejection of the findings of the 2010 Interagency Task Force, and the agency's BACT Guidance. The "White Paper" on BACT determinations for fossil-fueled electric generating units currently on the agency's website refers explicitly to the 2010 Report of the Interagency Task Force.

The President has advocated an "all of the above" energy policy, but the proposed rule strait-jackets the nation's electric generation options regardless of future changes in energy markets. While low natural gas prices, together with recent EPA regulations such as the Mercury and Air Toxics Standards Rule,[14] are leading electric generators to favor gas as a new generation option, too many uncertainties exist about the future price of natural gas to justify a rule that would prevent future construction of economic coal generation facilities. The Department of Energy recently increased its projections of future natural gas prices due to the expected development of LNG export facilities.[15] Recent cold weather in the East has led to skyrocketing natural gas and electricity prices.[16] Removing new coal as a competitive generation option would largely eliminate inter-fuel competition in the electric generation market.

New supercritical, ultra-supercritical and IGCC coal technologies offer feasible and economic means of power generation, and we would support alternative NSPS limiting CO2 emissions to the emissions rate achieved by these technologies. Such an alternative would be consistent with current EPA GHG BACT Guidance.

We are not persuaded by EPA's arguments advanced again in the Notice of Data Availability[17] that partial CCS represents an adequately demonstrated technology for commercial-scale coal-based electric generating units. The Technical Support Document released in conjunction with the February 5th NODA

---

[14] 77 Fed. Reg. 9304 (February 16, 2012).

[15] DOE/EIA, Annual Energy Outlook - Early Release (December 2013).

[16] See, e.g., Deep freeze exposes challenges for gas-dependent grid operator, available at: http://www.eenews.net/stories/1059993365.

[17] http://www2.epa.gov/sites/production/files/2014 01/documents/2013_proposed_cps_for_new_power_plants_noda.pdf

provides limited data on a number of carbon capture projects initiated without federal financial assistance.[18] Most of these projects are in the industrial sector, and were in existence at the time that the Interagency Task Force on CCS issued its 2010 findings that CCS had not been adequately demonstrated at utility-scale applications. These projects do not provide a sound basis for projecting the future commercialization of CCS in utility-scale applications, with or without government assistance. As discussed below, even CCS projects receiving substantial federal aid are encountering difficulties in project financing and power sales.

We request that EPA clarify that the NSPS for *new* units does not set the "floor" for purposes of a BACT analysis for *modified* units in a PSD permitting proceeding. Section 169(3) of the CAA provides that a BACT analysis may not result in an emissions limit that is less stringent than the emissions allowed by "any applicable [NSPS] standard established pursuant to section [111]." We urge EPA to clarify that because the agency has deferred setting a CO_2 NSPS for modified units, there is no "applicable" NSPS for purposes of *modified* units that are subject to PSD pre-construction permitting requirements on account of their CO_2 emissions. Without this clarification, EPA's NSPS for *new* sources could inadvertently affect many existing, "modified" facilities.

There is no rational basis in climate change policy for exempting CO2 emissions from natural gas generation while penalizing coal-based generation with uneconomic NSPS. Comprehensive global climate modeling analyses show that methane leakage from natural gas exploration, production, transport, and generation processes can offset all or more of the CO2 differential between coal and gas generation. The proposed rule is fundamentally unsound for this reason.

Supercritical, Ultra-Supercritical or IGCC Coal Technologies Should Set the Basis for Coal-Based CO2 NSPS

As an alternative to the proposed rule, we support a coal-based NSPS for CO2 emissions reflecting the performance of supercritical, ultra-supercritical or IGCC units equipped with the emissions controls needed to comply with other

---

[18] U.S. EPA, Notice of Data Availability, Technical Support Document (January 2014), available at http://www2.epa.gov/sites/production/files/2014-01/documents/2013_proposed_cps_for_new_power_plants_tsd.pdf.

applicable CAA requirements (e.g., scrubbers, SCRs, fabric filters, activated carbon injection.) Such an alternative would be consistent with the energy-efficiency emphasis of current GHG BACT Guidance, and could be revised in subsequent NSPS rulemakings to incorporate CCS technology if warranted. CCS requirements also could be applied through the case-by-case BACT review process, as already called for by agency guidance.

Providing a regulatory framework for the construction of new, highly-efficient coal units is consistent with the longer-term objective of ensuring the commercial development of second-generation CCS technologies. The few U.S. CCS-equipped power projects currently under construction with federal financial support may – if completed and successfully placed in operation - demonstrate the technical feasibility of first-generation CCS technologies on newly-constructed generation platforms. A new generation of supercritical, ultra-supercritical and IGCC units is needed to support the deployment of second-generation CCS technologies, which DOE projects may cost roughly 50% less than current first generation technologies.[19]

CCS Is Neither Adequately Demonstrated Nor Commercially Viable

CAA section 111(a)(1) defines a "standard of performance" as a "standard for emissions of air pollutants which reflects the degree of emission reduction which (taking into account … cost … and any nonair quality health and environmental impact and energy requirements) ... has been adequately demonstrated."

We disagree with EPA's assertion that a handful of government-supported CCS projects – or a group of facilities employing carbon dioxide capture for industrial purposes or for enhanced oil recovery - establishes CCS as an "adequately demonstrated" technology. The basic fact remains that there is not a single commercial-scale electric generation facility performing full or partial CCS currently in operation in the United States.

The status of the principal CCS projects that EPA relies upon for its finding that CCS has been adequately demonstrated belies the reasonableness of this finding:

---

[19] Dr. Julio Friedmann, *supra*, n. 2.

> Looking at the projects cited by EPA at the time of this writing: Kemper is under construction and not demonstrated (reference: Brian Toth presentation at the Coal Technology Symposium' held on March 5, 2014, in Washington D.C.); Sask is under construction and not demonstrated and has delayed start-up until July 2014 (reference: the Honorable Brad Wall, Premier of Saskatchewan at same symposium); TCEP/ Summit is not financed and hasn't started construction (reference: Sasha Meckler of Summit at the same symposium); HECA is not financed and has yet to start construction; NRG Parrish is has yet to start construction; AEP Mountaineer was only 2.3% of the plant gas stream and therefore should not qualify as significant as referenced in the rule making; Basin Electric/Dakota Gasification is a producer of natural gas and a fertilizer plant - not a power plant. Four of the six projects are gasifiers and high pressure technology not suited to pulverized coal or NGCC (natural gas combined cycle) electricity producing plants (which are at atmospheric pressure). Alstom suggests this summary demonstrates the EPA referenced projects fail to meet the "technically feasible" criteria. These technologies are not operating at significant scale at any site as of the rule publication. We do not support mandating technology based on proposed projects (many of which may never be built). These facts lead to the conclusion that the technology is not "adequately demonstrated" to be feasible at full scale.[20]

EPA's explanation of its reasoning in support of a finding that CCS has been "adequately demonstrated" displays the limited nature of the evidentiary support for this determination:

> With regards to post-combustion CCS, in the 2014 Proposal, we relied on three types of projects: (1) small-scale capture projects operated commercially at coal-fired power plants, (2) demonstration projects at existing power plants, and (3) large-scale projects in advanced stages of development at commercial power plants. EPA cited in the preamble three projects that fall into the first category: The AES Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) coal-fired power plants are equipped with post-combustion amine scrubbers developed by ABB/Lummus to capture CO2 for use in the food processing industry. The Searles Valley Minerals soda ash plant (Trona, CA) has captured CO2 from the flue gas of a coal-fired power plant via amine scrubbing for use in the production of soda ash. In each of these cases, small amounts of flue gas are treated, but a large percentage of CO2 is removed (generally 90% or more) from the treated gas stream. The technologies used in these plants are the same types that would be evaluated for use at a new conventional coal-fired power plant. All three of these projects were developed and operated prior to EPAct05. These projects show that the technology can be designed,

[20] Testimony of Robert Hilton, Vice President, Alstom, Before the U.S. House of Representatives Subcommittee on Environment and Subcommittee on Energy of the Committee on Science, Space, and Technology Hearing on Science of Capture and Storage: Understanding EPA's Carbon Rules (March 12, 2014), available at: http://docs.house.gov/meetings/SY/SY18/20140312/101893/HMTG-113-SY18-Wstate-HiltonR-20140312.pdf.

> constructed and operated in a commercial power plant environment at smaller scales. While those projects entail relatively small amounts of CO_2 removal (the two largest projects are designed to capture about 800 tons CO_2 per day, about 13% of the amount a 500 MW coal plant would need to achieve a limit of 1,100 lb CO_2/MWh), the technology used can be scaled up. <u>As noted above, under the case law, the determination of technical feasibility is forward-looking and may be based on reasonable projections, and here, EPA believes it is reasonable to project that the technology used by these projects can be scaled up. In particular, EPA believes the efforts at the Boundary Dam project alone demonstrate that companies are willing to pursue full-scale projects at this time.</u> Other projects described below further validate this belief. Further, comments by vendors indicate that they believe they are capable of scaling up the technology. For instance, one vendor indicated as far back as 2009, the ability to supply a capture unit capable of capturing about 3,000 tons of CO_2 per day, approximately half the amount needed to meet the requirements of the proposed rule for a new 500 MW coal plant. Building a system with two of these units would meet the requirements of the proposed rule.[21]

The SaskPower 110 megawatt Boundary Dam project that EPA highlights in support of its CCS determination is subsidized by the Canadian and provincial governments and will rely on EOR sales to offset a portion of its costs. SaskPower itself is a government utility owned by the province of Saskatchewan through its holding company, Crown Investments Corporation. MIT's summary of the Boundary Dam project's financial status reveals the extent of this government dependence, and the financial difficulties that have beset the project:

> The total cost of the project is estimated to be $1.24 billion. The Boundary Dam project received $240 million from the federal government in 2011, of which about $180 million has already been spent. The provincial government is also supporting the project. SaskPower announced in October 2013 that the project was $115 million over budget. Revenue from the sale of CO_2 is expected to offset the project costs. Sulphur dioxide (SO_2) will also be captured and sold.
>
> ***Comments:***
>
> The retrofit is located at Boundary Dam's Unit 3. The project will capture 95% or 1Mt/yr. This project has been re-sized from an earlier plan to build a 300 MW clean coal facility near Estevan which had been shelved by the previous provincial government because of its escalating cost ($1.5 billion to $3.8 billion). This smaller

[21] EPA NODA Technical Support Document (2014) at __ (emphasis added, footnotes omitted), available at http://www2.epa.gov/sites/production/files/2014-01/documents/2013_proposed_cps_for_new_power_plants_tsd.pdf.

> scale project has occurred after the federal government gave the province $240 million.[22]

The economic realities confronting large-scale CCS projects were vividly displayed in January 2014 by the decision by CPS Energy, the nation's largest municipally-owned electric and gas utility, to allow its power purchase agreement with the DOE-supported Summit Power Project in Texas to expire:

> Last week, CPS Energy allowed our agreement with Summit Power Group - for the purchase of 200 MW of electricity from the Texas Clean Energy Project - to expire. We signed the 25-year purchase power agreement (PPA) back in 2011, excited about the project that looks to develop a first-of-its-kind clean coal power plant that captures 90 percent of its carbon dioxide (CO2) to use for enhanced oil recovery in West Texas. Since 2011, the team at Summit has worked diligently to secure financing and begin construction. CPS Energy extended Summit's deadlines for milestones three times, understanding that power plant construction does not always follow a precise timeline.
>
> The project has continued to experience delays, however, and the energy landscape has changed. With abundant supplies of natural gas below our feet and prices for natural gas remaining moderate, the economics of energy produced from coal generation with carbon-capture have changed. The prudent option was to allow our agreement with Summit to end, while we consider the possibility of an updated PPA with the Texas Clean Energy Project in the future.
>
> This change will not affect our planning for future generation resources. We have and will continue to pursue the course that is best for our customers: further diversifying our electric generation fleet with no- and low-carbon resources and pursuing technology that helps customers manage their energy use. We remain hopeful this project can proceed and that carbon-capture technology will become feasible for existing coal plants.[23]

The recent cancellation of the Wolverine Power 600 MW coal-based power plant provides another example of the uneconomic nature of CCS applied to a conventional power project. The permitting process for the Wolverine Clean Energy Facility began in 2007, prior to EPA's Tailoring Rule and BACT Guidance

---

[22] MIT, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project, available at https://sequestration.mit.edu/tools/projects/boundary_dam.html

[23] *See*, http://newsroom.cpsenergy.com/blog/traditional-fuels/coal-traditional-fuels/cps-energys-ppa-texas-clean-energy-project-expired-dec-31/

for new fossil-fueled facilities. When these rules were issued, Wolverine supplemented its PSD Permit application with a "top-down" BACT analysis including CCS as an option:

> A detailed air pollution control permit application (Application No. 317-07) was prepared and submitted to the Michigan Department of Environmental Quality (MDEQ) in September of 2007. Since the air permit application was submitted and a draft permit issued, the U.S. Environmental Protection Agency (USEPA) has promulgated rules that regulate carbon dioxide (CO2) from certain stationary sources. On June 3, 2010, the USEPA issued a final rule that "tailors" the applicability provisions of the Prevention of Significant Deterioration (PSD) program under New Source Review (NSR) to regulate emissions of greenhouse gases (GHG). Under the Tailoring Rule certain proposed new major sources with a potential to emit more than 75,000 tons per year (TPY) of carbon dioxide equivalent (CO2e) became subject to new permitting requirements beginning in 2011...
>
> This report supplements the BACT review and determination for the proposed WCEV. The BACT review presented here follows a five step "top-down" process for GHG emissions from the proposed WCEV facility. Technologies evaluated include carbon capture and sequestration (CCS), biomass fuel augmentation, and energy efficiency opportunities in design of the plant.[24]

The Wolverine PSD permit application discusses and eliminates a variety of alternative engineering designs for the circulating fluid bed facility, on grounds that each would represent a fundamental redefinition of the project, contrary to EPA's BACT guidance and relevant case law. In the case of CO2, the applicant described the limited grounds on which to base project cost estimates:

> Cost estimates for emerging technology are difficult to estimate as equipment vendors are typically unwilling to disclose information on control systems during the development phase of the technology. Some costs can be obtained from the literature; however, without a history of a technology in a competitive market, there is no reliable information on the capital or operation and maintenance (O&M) cost of CO2 control.
>
> In addition to the cost of CO2 capture, CCS involves geologic or terrestrial sequestration or conversion of the CO2 for long-term storage. The costs associated with sequestration are very site-specific and can involve substantial costs for items such as pipeline construction, pumping, drilling and well construction, and

[24] AECOM Technical Services, Greenhouse Gas BACT Determination Supplement to Air Pollution Control Permit Application No. 317-07, Wolverine Clean Energy Venture Rogers City, MI (March 2011) at 1-1.

> monitoring. These costs are not estimated because there is too much uncertainty in the sequestration option for the site.[25]

Recognizing the need for government financial support for any application of CCS to the Wolverine project, the developers sought DOE assistance:

> CCS technologies are in the very early stage of development; consequently, very little information exists for these technologies. In 2010 Wolverine applied for CCS demonstration funds for the WCEV in response to the U.S. Department of Energy (USDOE) Solicitation DE-FOA-0000015 Section III D, "Large Scale Industrial CCS Projects from Industrial Sources" Technology Area 1. The demonstration project was to remove 1,000 metric tons per day of CO2 from the WCEV. The design of the CCS demonstration system included Hitachi Power Systems America's CO2 capture system and advanced amine technology to be provided by a Dow Chemical Company unit. The captured CO2 was proposed to be compressed and transported for EOR and deep saline sequestration purposes. The projected capital costs for the demonstration project were estimated for purposes of responding to the USDOE solicitation and are included in the following step-by-step, top-down BACT review.
> ...
>
> Wolverine applied for demonstration project funding from the USDOE to construct a CCS system at the WCEV. Burns and Roe Enterprises, Inc. conducted an engineering study to determine the appropriate CCS system for inclusion in the demonstration project for WCEV. Amine absorption was proposed under the USDOE grant with desorption/recovery, and EOR sequestration. The system was designed to remove 1,000 metric TPD CO2, roughly 7% of the CO2 emissions from the CFB units at WCEV.
>
> A technology is considered available if it can be obtained by the permit applicant through vendors with commercial terms of sale. An available technology is applicable if it can reasonably be installed and operated on the source type under consideration. Conceptual, pilot-scale, or developing technologies are not considered available under BACT. Control technologies that require government subsidies, such as projects funded under the U.S. Department of Energy Clean Coal Program, are not considered available control technologies. Based on these criteria, all of the technologies identified in this Section 3 can be eliminated from further consideration; however, the CCS system proposed under the USDOE demonstration funding for WCEV is carried forward in this evaluation for informational purposes.[26]

[25] *Id.*, at 1-4.

[26] *Id.*, at 3-6,7.

Wolverine's subsequent engineering cost analysis of the application of CCS to the project concluded that CCS was not economic, and should not be pursued even with government support:

> Table 3 shows the CCS system costs proposed under the USDOE demonstration funding for the WCEV. The capital costs, fixed O&M costs, and the variable O&M costs are taken directly from the USDOE demonstration project report (Wolverine Carbon Capture and Storage Project Phase 1 Draft Topical Report, USDOE Cooperative Agreement #DE-FE0002477, March 29, 2010). The capital costs are annualized over 20 years at 7% interest. The resultant cost effectiveness of the CCS technology is $126 per ton of CO2e removed.
>
> **Table 3 – Carbon Capture and Sequestration Costs for WCEV**
>
> Years 20
> Interest Rate 7
> Capital Recovery Factor 0.094
> Capital Costs $ 210,060,000
> Fixed O&M (years 2 - 20) $ 8,223,000
> Variable O&M $ 9,663,000
> Annual Capital Cost $19,828,178
> Annualized Cost $37,714,178
> CO2 Removed (metric TPY CO2e) 300,000
> Cost Effectiveness ($/ton) 126
>
> Determining an appropriate threshold cost for CO2e is a challenge. For comparison purposes, one could calculate the threshold value of cost effectiveness for CO2e based on the relative cost effectiveness of control of a criteria pollutant at some threshold value per ton of pollutant removed and the major source threshold of 100 TPY. This approach is supported by the USEPA's own rulemaking under the "Tailoring Rule." Through rulemaking, the USEPA has "tailored" greenhouse gases such that 100,000 tons of CO2e is equal to100 tons of a criteria pollutant for the purpose of PSD applicability. So, by USEPA's own rulemaking construct, if a criteria pollutant has a cost effectiveness threshold in the range of $8,000 per ton, then the CO2e cost effectiveness should be 0.001 times as much, or $8/ton controlled. Based on this criterion, the CCS demonstration system for the WCEV is found to be infeasible based on cost.[27]

After rejecting CCS as BACT on economic grounds, the Wolverine permit analyzed other options for reducing CO2 emissions from the planned CFB units. It concluded that modest biomass cofiring, with certain engineering design changes, constituted BACT for the two-unit plant:

[27] *Id*., at 3-13.

Step 5 – Select BACT CFB Boilers

BACT is determined to be the following:

Combustion of at least 5% biomass on a heat input basis on a 12-month rolling average,
Specification of cost effective variable speed motors for all system components with a motor over 100 horsepower, and
Following the manufacturer's guidelines on O&M of plant components

> These steps will result in a reduction of 4.7% of CO2e emissions attributable to fossil fuel combustion. The total CO2e emission from the CFB units will be capped at 5,722,000 short tons of carbon dioxide per 12-month rolling average. The 5,722,000 short tons will be directly measured with continuous emission monitors at the CFB stack and represents the CO2 emissions from the carbon in the fuel and limestone calcinations in the CFB bed.[28]

The Wolverine project ultimately was unable to move forward. On December 17, 2013, Wolverine Power's CEO Eric Baker advised community representatives that the project was cancelled due to the difficulty in meeting environmental standards. Work on the project was suspended in January 2012.[29]

There are similar cases of BACT reviews evaluating and rejecting CCS on economic grounds, such as the proposed Taylorsville coal gasification facility in Illinois. That project - subsequently cancelled - offered the opportunity to capture a pure stream of CO2 from the gasification process, without the need for costly post-combustion capture technologies.[30] Illinois EPA rejected the application of CCS on economic grounds.

Finally, we note the recent testimony provided by Alstom - one of the leading providers of emission control technologies to the global electric utility market - assessing the commercial readiness of CCS:

> Alstom has taken each of its Carbon Capture related technologies from the bench level to small and then larger pilots, followed by validation scale demonstrations

---

[28] *Id*., at 3-15.

[29] http://www.sourcewatch.org/index.php?title=Wolverine_Clean_Energy_Venture#December_2013:_Project_cancelled.

[30] Illinois EPA, "Project Summary for a Construction Permit Application from Christian County Generation, LLC for the Taylorville Energy Center, Christian County, Illinois" (2011).

with the aim to finally reach commercial scale demonstration. To date, no Carbon Capture technologies have been deployed at commercial scale. Alstom has successfully taken several of its technologies through the validation scale demonstration. This stage is the proof of technology in real field conditions (or in this case actual power plant flue gas). It is at this point we can say confidently that the basic technology works.

However, the final stage to reach commercial status is to perform a demonstration at full commercial scale. There are several reasons for this requirement. It is critical to be at commercial scale to define the risk of offering the technology. This cannot be defined until the technology can be shown to work at full scale. This is the first opportunity that we have to work with the exact equipment in the exact operating conditions that will become the subject of contractual conditions when the technology is declared commercial and is offered under standard commercial terms including performance and other contractual guarantees. This also becomes the first opportunity to optimize the process and equipment to effect best performance and, very importantly, seek cost reduction. These too are required to define commercial contractual conditions. Finally, our customers would be reluctant to invest in Carbon Capture technologies that have not been demonstrated to full commercial scale.

Based on these criteria, Alstom does not currently deem its technologies for Carbon Capture commercial and, to my knowledge, there are no other technology suppliers globally that can meet this criteria or are willing to make a normal commercial contract for CCS at commercial scale. I emphasize however that the technologies being developed by Alstom and others work successfully.[31]

We agree with Alstom's basic conclusion that the effect of this rule will be to deter - not stimulate - progress in the development of CCS technologies:

(T)his regulation will essentially stop the development of CCS. Without new coal plants, it is unlikely technology developers will continue to invest in CCS development. Since the proposed regulation provides a significantly lower cost alternative (NGCC without controls) to the application of CCS to coal, there is unlikely to be a market for at least 10 years, and most R&D cannot be sustained for that period. Industry bases R&D on market potential and return on investment. With no market in sight, investment will stop. One only need to look at slowing pace of private and public investment world-wide in CCS projects as shown in the annual survey of the Global Carbon Capture and Storage Institute (GCCSI),

---

[31] Testimony of Robert Hilton, Vice President, Alstom, Before the U.S. House of Representatives Subcommittee on Environment and Subcommittee on Energy of the Committee on Science, Space, and Technology, Hearing on Science of Capture and Storage: Understanding EPA's Carbon Rules (March 12, 2014), available at: http://docs.house.gov/meetings/SY/SY18/20140312/101893/HMTG-113-SY18-Wstate-HiltonR-20140312.pdf (emphasis added.)

which results from economic conditions and lack of progress on climate change negotiations as proof that EPA's assumption are unrealistic.[32]

Alstom's conclusions about the commercial readiness of CCS technologies are reflected in the findings of the 2013 Roadmap of the Carbon Sequestration Leadership Forum (CSLF), the multilateral ministerial-level body charged with helping to advance global CCS demonstration and deployment. CSLF's most recent assessment of the status of CCS demonstration projects found that:

> In short, capturing CO2 works and there has been significant progress with CO2 capture from industrial sources with high CO2 concentration. However, certain challenges remain:
> The cost and energy penalty are high for all 1st generation capture technologies.
> <u>The scale-up and integration of CO2 capture systems for power generation and industries that do not produce high-purity CO2 are limited, and may not sufficiently advance for at least the next 5 – 10 years</u>.
> CO2 capture technologies suited to a range of industrial processes exist, but have not been adopted, demonstrated and validated for specific use. Examples of such industries include cement, iron and steel, petrochemical, aluminum, and pulp and paper.[33]

The CCS Interagency Task Force Findings And EPA BACT Guidance Do Not Support CCS as "Adequately Demonstrated"

EPA's November 2010 Guidance on GHG BACT in the NSR permitting process recognized CCS as an "available" technology option but declined to mandate its application, citing the uncertainties about CCS commercial availability noted by the Interagency Task Force:

> For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be

---

[32] *Id*., at 6-7.

[33] Carbon Sequestration Leadership Forum, 2013 Carbon Sequestration Technology Roadmap (2013) at 9 (emphasis added.)

> listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an option that merits initial consideration and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail.[34]

EPA's BACT Guidance supported key findings of the Interagency Task Force on CCS, including its finding that CCS technologies "are not ready for widespread implementation" due to the lack of adequate commercial-scale demonstration:

> … [A] control option is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supports the Task Force's recommendations concerning ongoing investment in demonstrations of the CCS technologies based on the report's conclusion that: "<u>Current technologies could be used to capture CO2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application.</u> <u>Since the CO2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment</u>."[35]

In sum, EPA's November 2010 BACT Guidance recommended that CCS be listed as an "available" option for reducing GHG emissions from major new and

---

[34] U.S. EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases" (November 10, 2010) at 33-34 (footnotes omitted.)

[35] *Id*., at n. 82 (emphasis added, citation omitted.)

modified industrial sources at the initial stage of the BACT review process, but did not mandate its incorporation in PSD construction permits. It expressed concern about the lack of utility-scale commercial demonstrations of CCS, and noted the uncertainties associated with relatively small-scale industrial applications, such as those EPA relies upon in the February 5 NODA.

The BACT Guidance White Paper for new fossil-fueled generating units currently available on the EPA website[36] finds that "full-scale carbon separation and capture systems have not yet been installed and fully integrated at an EGU." EPA's White Paper next refers potential permit applicants to the findings of the 2010 Interagency Task Force on CCS:

> One recent study prepared for the U.S. DOE by the Pacific Northwest National Laboratory (PNNL, 2009) evaluated the development status of various CCS technologies. The study addressed the availability of capture processes; transportation options (CO2 pipelines); injection technologies; and measurement, verification, and monitoring technologies. The study concluded that, in general, CCS is technically viable today. However, full-scale carbon separation and capture systems have not yet been installed and fully integrated at an EGU. The study also did not address the cost or energy requirements of implementing CCS technology. For up-to-date information on Department of Energy's National Energy Technology Laboratory's (NETL) Carbon Sequestration Program go to the NETL web site at: http://www.netl.doe.gov/technologies/carbon_seq/.
>
> In 2010, an Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of CCS technologies. The Task Force is specifically charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration projects online by 2016. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical barriers to implementation. For additional information on the Task Force and its findings on CCS, go to: http://www.epa.gov/climatechange/policy/ccs_task_force.html. <u>Because the development status of CCS technologies and their applicability to coal-fired EGUs are thoroughly discussed in the Task Force report, there will be no further discussion in this document</u>.[37]

---

[36] EPA, AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS (October 2010), available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

[37] *Id.*, at 26 (emphasis added.)

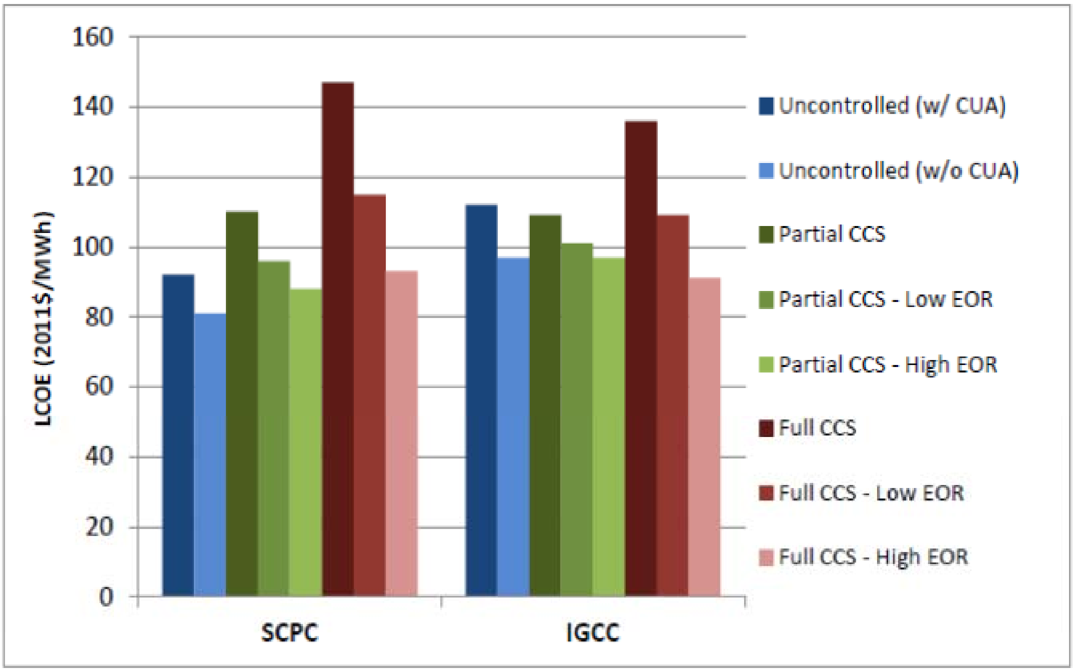
EOR Markets for CO2 Are Limited and Are Not Sufficient to Offset CCS Costs

We disagree with EPA's view that potential enhanced oil recovery (EOR) applications represent a viable path for capturing and sequestering CO2 emissions from utility-scale power plants. Our concerns in this regard are two-fold: 1) EOR opportunities are inherently limited to petroleum-producing regions, or areas with available pipeline access, and do not extend to the full range of states to which the NSPS apply; and 2) the agency's assumed $20/ton to $40/ton revenue stream from EOR CO2 sales is inadequate to offset the full costs of CO2 capture, compression and transport. This inadequacy is recognized by proposed federal legislation such as S. 3581 (112th Cong., 2d Sess.)

We defer to other expert commentators on the economics of utility scale CCS-generated CO2 in EOR market applications. We note, however, that several planned or proposed CO2/EOR capture projects cited by EPA are in the industrial sector (see, e.g., RIA at 4-19), and involve much smaller quantities of CO2 than those generated by a typical 600-1,300 MWe coal-based generating unit.

EPA's economic analysis of the comparative levelized generating costs of supercritical pulverized coal (SCPC) units with and without EOR indicates the substantial cost penalties associated with partial or full CCS relative to an uncontrolled new SCPC unit, as shown in the chart below:

EPA Estimates of the Levelized Cost of Electricity from Uncontrolled Coal and Coal with Partial or Full CCS



Source: EPA, Regulatory Impact Analysis, Fig. 5-7 (2013). CUA is a "climate uncertainty adder" that increases the weighted average cost of capital by 3%. The "low" EOR estimates in the above chart assume CO2 sales at $20/ton, and the "high" EOR estimates assume CO2 sales at $40/ton.

EPA's RIA for the proposed rule shows that CCS raises the cost of electricity from a new supercritical unit by approximately 36% to 81%, depending on whether it uses partial or full CCS.[38] Costs for plants that have access to EOR markets for CO2 sales are 17% to 42% higher than EPA's base case. Given the relatively lower cost of generation that EPA projects for natural gas combined-cycle units, these additional cost penalties for new coal-based units would pose virtually insurmountable barriers for obtaining state regulatory approvals in states with traditional utility regulation.

---

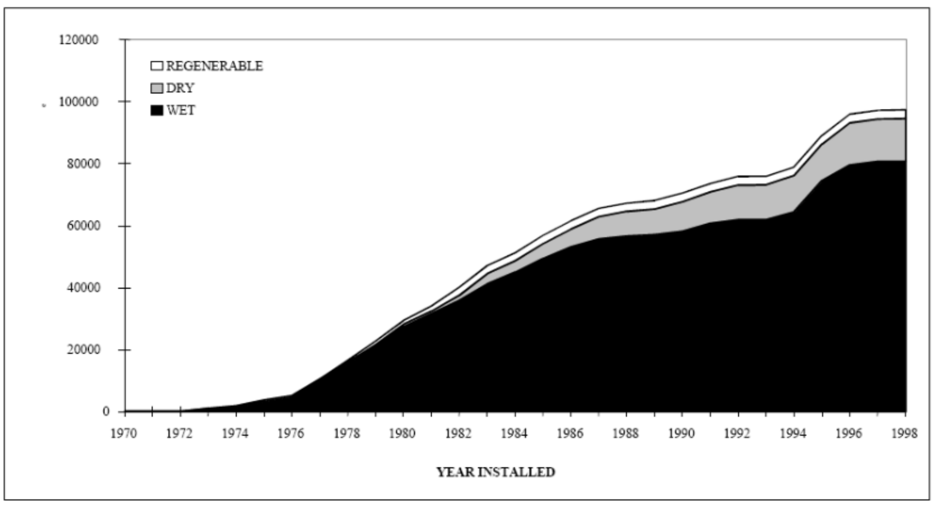
[38] EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (2013) at Fig. 5-7.

Prior NSPS Determinations Have Reflected Commercial-Scale Deployments

Previous EPS NSPS rules requiring the application of relatively new and unproven emission control technologies, such as flue gas desulfurization (FGD) for SO2 control, were promulgated only after FGD technologies had been extensively tested and successfully applied at commercial-scale electric generating units. The initial 1971 SO2 NSPS required coal-based units to meet an emission rate limit of 1.2 lbs. SO2/MMBTU, which could be achieved by FGD or by low-sulfur coals without add-on controls.[39]

As shown by the chart below, there was little if any commercial-scale operating experience with FGD technologies at the time the 1971 NSPS were developed. After the rule was promulgated, many utilities chose to adopt FGD technology despite its optional status. The experience gained through these deployments provided the basis for EPA's subsequent revision of the SO2 NSPS to require the use of FGD technology.

Historical Application of FGD Technology in the United States, 1970-1998



Source: U.S. EPA, CONTROLLING SO2 EMISSIONS: A REVIEW OF TECHNOLOGIES, EPA/600/R-00/093 (November 2000).

The 1979 Revised NSPS for SO2 control required a sliding-scale 70%-90% reduction of SO2 emissions with a maximum emission rate of 1.2 lbs.

[39] 36 FR 24876 (December 23, 1971).

SO2/MMBTU.[40] As of November 1978, 46 operating commercial-scale electric generating units were equipped with FGD in the U.S., with another 43 units under construction.[41] This extensive operating experience with FGD technologies, together with large projected increases in SO2 emissions under prior NSPS and the need to prevent air quality deterioration, provided the legislative basis for the "percentage reduction" clause added to Section 111 by the 1977 Clean Air Act Amendments.[42]

The same measured approach to the application of CCS should apply in this rulemaking, since NSPS set a floor – not a ceiling - for emission rate limitations. The NSPS floor is subject to potentially more stringent requirements under the case-by-case BACT reviews in the New Source Review program. As discussed *supra*, EPA's 2010 BACT Guidance recommended that CCS be "listed" at the initial stage of the BACT review process as an "available" option for reducing GHG emissions from major new and modified utility and industrial sources, but did not mandate its incorporation in PSD construction permits.[43] These recommendations reflected EPA's support for the findings of the 2010 Interagency CCS Task Force. For EPA now to propose CCS as a mandatory component of NSPS for GHG emissions from coal-based electric generation sources constitutes both a rejection of the findings of the 2010 Interagency Task Force, and the agency's BACT Guidance.

Climate Change Considerations

The proposed NSPS would discourage the construction of new advanced coal generation units while favoring new natural gas generation without any CO2 controls. New research at Harvard University raises substantial questions about the accuracy and reliability of U.S. EPA's estimates of current methane emissions from the power generation and other sectors. These concerns, summarized below, suggest that previous estimates of the near-equivalence of coal- and natural

---

[40] 44 FR 33580 (June 11, 1979).

[41] National Research Council, Committee on Evaluation of Sulfur Oxides Control Technology, *Flue Gas Desulfurization* (1980) at Table 4.3.

[42] *See id.*, at 13-17.

[43] U.S. EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases" (November 10, 2010).

gas-based generation deserve further consideration, particularly in view of the agency's recent determination[44] to increase the global warming potential of methane from 21x to 25x CO2e:

> This study quantitatively estimates the spatial distribution of anthropogenic methane sources in the United States by combining comprehensive atmospheric methane observations, extensive spatial datasets, and a high-resolution atmospheric transport model. Results show that current inventories from the US Environmental Protection Agency (EPA) and the Emissions Database for Global Atmospheric Research underestimate methane emissions nationally by a factor of ∼1.5 and ∼1.7, respectively. Our study indicates that emissions due to ruminants and manure are up to twice the magnitude of existing inventories. In addition, the discrepancy in methane source estimates is particularly pronounced in the south-central United States, where we find total emissions are ∼2.7 times greater than in most inventories and account for 24 ± 3% of national emissions. The spatial patterns of our emission fluxes and observed methane–propane correlations indicate that fossil fuel extraction and refining are major contributors (45 ± 13%) in the south-central United States. This result suggests that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR, the most comprehensive global methane inventory. These results cast doubt on the US EPA's recent decision to downscale its estimate of national natural gas emissions by 25–30%. Overall, we conclude that methane emissions associated with both the animal husbandry and fossil fuel industries have larger greenhouse gas impacts than indicated by existing inventories.[45]

Research by Dr. Tom Wigley, a prominent climate scientist at the National Center for Atmospheric Research, suggests that increased dependence on natural gas could be counterproductive due to the long-term effects of methane leakage from gas exploration, production, transportation and generation:

> Carbon dioxide (CO2) emissions from fossil fuel combustion may be reduced by using natural gas rather than coal to produce energy. Gas produces approximately half the amount of CO2 per unit of primary energy compared with coal. Here we consider a scenario where a fraction of coal usage is replaced by natural gas (i.e., methane, CH4) over a given time period, and where a percentage of the gas production is assumed to leak into the atmosphere. The additional CH4 from leakage adds to the radiative forcing of the climate system, offsetting the reduction in CO2 forcing that accompanies the transition from coal to gas. We also consider the effects

---

[44] See, http://www.epa.gov/ghgreporting/documents/pdf/2013/documents/2013-data-elements.pdf

[45] Scot M. Miller, *et al*., (2013) Anthropogenic emissions of methane in the United States, available at http://www.pnas.org/content/110/50/20018.abstract?sid=3eb74244-dbed-4577-8b0d-04307adaa423.

> of: methane leakage from coal mining; changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols; and differences in the efficiency of electricity production between coal- and gas-fired power generation. On balance, these factors more than offset the reduction in warming due to reduced CO2 emissions. When gas replaces coal there is additional warming out to 2050 with an assumed leakage rate of 0%, and out to 2140 if the leakage rate is as high as 10%. The overall effects on global-mean temperature over the 21st century, however, are small. …
>
> In our analyses, the temperature differences between the baseline and coal-to-gas scenarios are small (less than 0.1°C) out to at least 2100. The most important result, however, in accord with the above authors, is that, <u>unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change</u>. This is contrary to claims such as that by Ridley (2011) who states (p. 5), with regard to the exploitation of shale gas, that it will "accelerate the decarbonisation of the world economy". The key point here is that it is not decarbonisation per se that is the goal, but the attendant reduction of climate change. Indeed, the shorter-term effects are in the opposite direction. Given the small climate differences between the baseline and the coal-to-gas scenarios, decisions regarding further exploitation of gas reserves should be based on resource availability (both gas and water), the economics of extraction, and environmental impacts unrelated to climate change.[46]

Wigley's analysis raises clear doubts about the climate-related impacts of the proposed NSPS that we believe merit further analysis before the rule is finalized.

EPA Should Clarify that the NSPS for New Units Does Not Establish the "Floor" for BACT Analysis for Modified Units

In addition to addressing the issues above, we request that EPA clarify that the NSPS for *new* units does not set the "floor" for purposes of a BACT analysis for *modified* units in a PSD permitting proceeding. Section 169(3) of the CAA provides that a BACT analysis may not result in an emissions limit that is less stringent than the emissions allowed by "any applicable [NSPS] standard established pursuant to section [111]." In other words, if there is an "applicable" NSPS for a particular facility subject to a PSD permitting proceeding then that NSPS establishes the "floor" for the BACT analysis.

We urge EPA to clarify that because the agency has deferred setting a CO_2 NSPS for modified units, there is no "applicable" NSPS for purposes of *modified*

---

[46] Tom M.L. Wigley (2011), Coal to gas: the influence of methane leakage, *Climatic Change* DOI 10.1007/s10584-011-0217-3 (emphasis added) at 1, 8.

units that are subject to PSD pre-construction permitting requirements on account of their CO_2 emissions. Without this clarification, EPA's NSPS for *new* sources could inadvertently affect many existing, "modified" facilities.

Conclusion

EPA's proposed rule requiring carbon capture and storage technology on new coal power plants is unreasonable and is not supported by the record in this rulemaking or by applicable law. It will force the nation and electric consumers to an uncertain future of increasing reliance on natural gas generation. The proposed rule is directly at odds with an "All of the Above" energy policy.

The Administration's Task Force on CCS technology determined in 2010 that CCS is not adequately demonstrated in utility scale applications. The majority of the projects evaluated by EPA for this rule, and for the NODA, were in existence at the time of the Task Force Report. The few U.S. energy facilities that EPA uses to support its finding that CCS is adequately demonstrated are all in various stages of construction, and all rely on government financial support. The Canadian plant EPA relies upon is owned by a government utility.

The nation needs a clear path to allow the construction of advanced new coal generating plants without CCS. These new plants can serve as the platforms for CCS development when second-generation CCS technology is available at lower costs. U.S. DOE has testified before Congress that first generation CCS technology would raise electricity costs by 80%, and is too expensive to be deployed without government support.[47]

Forcing the nation to abandon its most abundant and economic energy resource is not good energy or environmental policy, and will harm workers and consumers through reduced jobs and exposure to higher energy costs. The elimination of new coal generation in favor of natural gas will have no measurable impact on global climate due to the greenhouse gas emissions associated with natural gas development and combustion.

[47] Dr. Julio Friedmann, *supra*, n. 2.

Thank you for the opportunity to comment on this important rule. We will appreciate your attention to these comments.

Sincerely,

James Hunter

Jim Hunter
Director, Utility Department
International Brotherhood of
Electrical Workers, AFL-CIO

President, UJEP

Cc: Honorable Regina McCarthy, US EPA
Richard L. Trumka, AFL-CIO
Newton B. Jones, IBB
Edwin D. Hill, IBEW
Dennis R. Pierce, IBT Rail Conference
Walter W. Wise, IWINTL
John Previsch, SMART - Transportation Division
Robert A. Scardelletti, TCU
William P. Hite, UA
Cecil E. Roberts, Jr., UMWA
D. Michael Langford, UWUA