CLEAN AIR TASK FORCE

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Air and Radiation Docket Information Center
U.S. Environmental Protection Agency
Mail Code 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
Attn: Docket ID No. EPA-HQ-OAR-2013-0495

Re: **Comments of Clean Air Task Force** on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430 (Jan. 8, 2014); *and* Notice of Data Availability ("NODA") in Support of Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 10,750 (Feb. 26, 2014)

Clean Air Task Force ("CATF") respectfully submits these comments on the U.S. Environmental Protection Agency's ("EPA" or the "Agency") proposed performance standards for carbon dioxide ("CO_2") emissions from subpart Da electric utility generating units ("EGUs"), and on the Notice of Data Availability ("NODA") in support of those proposed standards. Founded in 1996, CATF is a nonprofit organization dedicated to restoring clean air and healthy environments through scientific research, public education, private sector collaboration, and legal advocacy.

CATF also joins the comments submitted today by Earthjustice, Environmental Defense Fund, Environmental Law and Policy Center, Natural Resources Defense Council, Sierra Club and Southern Environmental Law Center ("Joint Environmental Commenters").[1] CATF submits these additional comments separately in order to emphasize, strongly support, and supplement EPA's record concerning the commercial-scale availability of the suite of technologies referred to as "carbon capture and sequestration" or "carbon capture and storage" (hereinafter, "CCS"),

[1] CATF does not join Section VI of the Joint Environmental comments, however, as our position is that the Agency is within its authority to codify its final standards either under existing subparts Da and KKKK, or to establish a new TTTT for that purpose, and that either choice allows for effective and flexible existing source performance standards under section 111(d).

including ongoing incidental long-term containment of CO_2 in enhanced oil recovery ("EOR") operations.[2] It is CATF's firmly held position that the rapid expansion of CCS systems – both in the U.S. and abroad – are necessary in order to control anthropogenic CO_2 in a timely enough manner so as to avoid the worst climate impacts and damage. Our comments, with the accompanying detailed Technical Appendix, are intended to provide the Agency with the most up-to-date information on the status of global CCS projects. Because of the high degree of activity in this field, new information on the status of CCS has been made available since the proposed rule was signed, and even since EPA published its NODA in February of this year.[3]

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[2] Comments filed by the Electric Reliability Coordinating Council dated May 9, 2014[2], assert that the recently-released National Climate Assessment (NCA) questions whether CCS is ready to be deployed. In its comments, ERCC states that "[t]he NCA's conclusions regarding the commercial readiness of CCS technology is [sic] clear and stark," however NCA never claims to make such conclusions on the readiness of CCS or any other technology. ERCC Comments, Docket No. EPA-HQ-OAR-2013-0495-_____ (available at http://www.electricreliability.org/sites/default/files/media_files/ERCC_--_Comments_on_GHG_NSPS_%28May_9__2014%29_0.pdf. Instead, the sentences ERCC points to as support for its claim that the NCA shows "CCS is not ready for commercial deployment" are passing statements made in a chapter that simply analyzes the connections between energy, land, and water systems. They do not address or contradict anything on which EPA bases its BSER determination.

[3] *See, e.g.,* IEA Greenhouse Gas R&D Programme, Carbon Capture and Storage: Proven and it Works, (Mar. 2014) (Ex. App. – 54) *available at*: http://www.ieaghg.org/docs/general_publications/CCS - Proven and it Works Update High Resolution.pdf; Paul Noothout, Frank Wiersma, *et al*., "CO2 Pipeline Infrastructure Reference Manual" (Jan. 2014) [*hereinafter "*IEAGHG Pipeline Manual"], report prepared for the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) and the Global CCS Institute, (Ex. App. – 55) *available at:* http://www.globalccsinstitute.com/publications/co2-pipeline-infrastructure; Jordan K Eccles, Lincoln Pratson, *A 'carbonshed' assessment of small- vs. large-scale CCS deployment*, 113 Applied Energy 352, 357 (2014) (Ex. App. – 58) *available at*: http://www.sciencedirect.com/science/article/pii/S0306261913005680; Petroleum Technology Research Centre, *What Happens When CO_2 is Stored Underground: Q&A from the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project*, (2014) (Ex. App. – 76) *available at*: http://www.globalccsinstitute.com/publications/what-happens-when-co2-stored-underground-qa-ieaghg-weyburn-midale-co2-monitoring-and.;
Kuuskraa and Wallace, *CO_2-EOR Set for Growth as New CO_2 Supplies Emerge,* **Oil & Gas J.** (Apr. 7, 2014) (attached here at Ex. App. – 79) *available at*: http://www.ogj.com/articles/print/volume-112/issue-4/special-report-eor-heavy-oil-survey/co-sub-2-sub-eor-set-for-growth-as-new-co-sub-2-sub-supplies-emerge.html.; NETL, *Subsurface Sources of CO_2 in the Contiguous United States, Vol. I: Discovered Reservoirs*, (Mar. 5, 2014) (Ex. App. – 91) *available at*: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Subsurface-Sources-of-CO2_discovered_final_working.pdf; NETL, *Subsurface Sources of CO_2 in the United States, Vol. II: Exploration of CO_2 Systems*, (Mar. 26, 2014) (Ex. App. – 92) *available at*:

This information further supports EPA's determination that CCS technologies are adequately demonstrated as the "best system of emissions reduction" supporting the proposed performance standard for new coal-fired Subpart Da units.[4]

CATF congratulates the EPA for taking this significant step towards meaningful greenhouse gas emissions reductions from EGUs. It is hard to overstate the importance of gaining control over anthropogenic emissions of CO_2, which persist in the atmosphere for a century, often longer. *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,* 74 Fed. Reg. 66,496, 66,517 n.18 (Dec. 15, 2009). We urge the Agency to finalize new source standards expeditiously, and we look forward to the upcoming opportunity to comment on EPA's existing source emissions standards and guidelines proposal. Without significant CO_2 reductions from this source category, it will be impossible to meet the goals laid out by the President in his 2013 Climate Action Plan.[5]

I. Introduction – Legal Basis for the Standards

EPA properly has found that greenhouse gas emissions, including CO_2, seriously endanger public health and welfare. In particular, "global atmospheric [CO_2] concentration has increased about 38 percent from pre-industrial levels to 2009, and almost all of the increase is due to anthropogenic emissions," and "the public health of current generations is endangered and

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http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Subsurface_CO_Exploration_03_26_2014.pdf.

[4] Fossil fuel-fired EGUs and stationary gas turbines were first listed as section 111 source categories in 1971. *See* Air Pollution Prevention and Control: List of Categories of Stationary Sources, 36 Fed. Reg. 5,931 (Mar. 31, 1971) (including fossil-fuel fired electric steam generating units and boilers). Currently, performance standards for fossil-fuel fired EGUs are codified at 40 C.F.R. part 60, subpart Da, and those for stationary turbines, including natural gas combined cycle and single cycle plants, are codified at 40 C.F.R. Part 60, subpart KKKK. EPA has not determined that CCS is an adequately demonstrated BSER supporting its proposed performance standards for natural gas-fired units (subpart Da or KKKK) at this point. CATF does not take a position on this question in the context of this proceeding. However we do believe this technology is technically feasible and economically reasonable in some instances for use on natural gas fired generating units and must be evaluated and in some instances required as BACT in individual permitting proceedings. We note particularly that recently announced integrated CCS projects planned for future development include a commercial scale application of CCS on a natural gas combined cycle unit in Scotland. *See infra,* Technical Appendix at (I)(b)(i)(3). We urge EPA to continue to assess this issue.

[5] Exec. Office of the President, "The President's Climate Action Plan," (June 2013) *available at*: http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf (aiming to reduce greenhouse gas emissions by 17% below 2005 levels by 2020).

that the threat to public health for both current and future generations will likely mount over time [as these emissions] continue to accumulate in the atmosphere …result[ing] in ever greater rates of climate change." 74 Fed. Reg. 66,496, 66,517, 524 (Dec. 15, 2009). And in 2011, the Supreme Court held that the Clean Air Act ("CAA") authorizes CO_2 standards for power plants under section 111, such that common-law actions in tort are preempted against coal-fired electric utilities for damages due to their emissions of climate pollution. *Am. Elec. Power Co. v. Connecticut ("AEP")*, 131 S.Ct. 2527, 2537-39 (2011). EPA's authority to propose performance standards for this industry is therefore without doubt.

A. EPA's Proposed Standards Must Reflect the *Best* System of Emissions Reduction[6] Adequately Demonstrated

Standards of performance must reflect "the degree of emission limitation achievable through the application of the best system of emission reduction ["BSER"] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1). Since section 111 was first enacted in 1970, courts have interpreted this language to mean that "it is the system that must be adequately demonstrated, and the standard which must be achievable." *Essex Chemical Corp. v. Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). EPA has discretion in balancing the statutory factors, *Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (citing *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992)), but EPA's discretion under section 111 is not unbounded – courts have recognized that these standards must reflect the most highly-effective emissions reduction systems technically and economically feasible, including new and innovative pollution reduction methods where available even though not in routine use, as discussed below.

When originally enacted, section 111 contained language defining "standards of performance" in the same terms as those codified today. *Compare Essex Chemical,* 486 F.2d at 433 (quoting 42 U.S.C. § 1857c-6(a)(1) (1970)) *with* 42 U.S.C. § 7411(a)(1) (2014)(same language). In 1977, Congress amended select CAA provisions in order to avoid a "race to the bottom": individual states were relaxing pollution control standards to lure industry from states with more stringent requirements, thus gaining a competitive advantage over their more environmentally-conscious neighbors. *See* H.R. Rep. No. 95-294, at 184 (1977). To counteract this trend and "create incentives for improved technology," Congress amended section 111 so as to mandate the adoption of the "best technological system of continuous emissions reduction." 42 U.S.C. § 7411(a) (1977); Clean Air Act Conference Report: Statement of Intent; Clarification

[6] CATF Joins Joint Environmental Commenters in seeking final subpart Da standards that are expressed on a net output basis, and as well in seeking more robust net emissions rate standards for subpart KKKK units. These separate comments, however, will focus exclusively on EPA's BSER determination.

of Select Provisions, 123 Cong. Rec. 27071 (1977). *See also* H.R. Rep. No. 95-294, at 189 ("[I]t is prudent public policy to require achievement of the maximum degree of emission reduction from new sources, while encouraging the development of innovative technological means of achieving equal or better degrees of control."); *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981) ("[S]ection 111 was intended 'to assure the use of available technology and to stimulate the development of new technology.'" (quoting S. Rep. No. 95-127, at 114 (1977)); *Sierra Pacific Power Co. v. EPA*, 647 F.2d 60, 68 (9th Cir. 1981) (holding that Congress intended that new source emissions controlled under section 111 would be reduced "to a minimum").

The 1977 amendments defined best technology "in terms of 'long-term growth,' [and] 'long-term cost savings.'" *Sierra Club*, 657 F.2d at 331 (quoting Clean Air Act Conference Report, 123 Cong. Rec. at 27,021). Requiring new stationary sources to adopt pollution control technology at the time of construction, when plant owners and operators can most afford the investment, achieves long term savings as compared with the option of waiting for environmental degradation to occur and only then requiring retrofits. *See* H.R. Rep. No. 95-294 at 185*; see also Nat'l Asphalt Pavement Ass'n,* 539 F.2d at 783. The legislative history also states that the costs of applying pollution control should be "considered by the owner of a large new source of pollution as a normal and proper expense of doing business." H.R. Rep. No. 95-294 at 184. Among other things, the 1977 amendments were "intended to create incentives for improved technology, which could achieve greater or equivalent emission reduction at equivalent or lower cost, energy demand, and environmental impacts." *Id.* at 186.

In 1990, Congress amended section 111 once again, reviving the original (1970) language of section 111(a)(1). While the 1990 Amendments removed explicit references to the selection of technology, the D.C. Circuit has since expressed that the forward looking and technology-forcing nature of the statute has not changed. The recent case law aligns with decisions in all of the cases since section 111 was enacted, holding that EPA must look to the technological vanguard when setting new source standards so as to encourage innovation and avoid the additional costs associated with the need to later retrofit controls. "Because it applies only to new sources, … section 111 'looks toward what may fairly be projected for the regulated *future*, rather than the state of the art at present.'" *Lignite Energy Council*, 198 F.3d at 934 (quoting *Portland Cement I*, 486 F.2d at 391) (emphasis added).

To that end, "[t]he statutory factors which EPA must weigh [when setting performance standards] are broadly defined and include within their ambit subfactors such as technological innovation." *Sierra Club*, 657 F.2d at 346. The agency may thus promulgate standards that reflect "improved design and operational advances" that the regulated industry has yet to realize, "so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Id.* at 364; *see also Portland Cement*

Ass'n v. EPA (*Portland Cement III*), 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology). Moreover, EPA can "extrapolat[e] . . . a technology's performance in other industries," and look beyond domestic facilities to those used abroad. *Lignite Energy Council,* 198 F.3d at 933-34 & n.3.

EPA is not constrained to establish new source emissions limits that are based on systems of emission reduction that are in "widespread use" in a particular industry. To the contrary, courts have repeatedly noted, following the decision in *Essex Chemical,* 486 F.2d at 433-34, that "an achievable standard is one … within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption." *See also Nat'l Asphalt Pavement Ass'n v. Train,* 539 F.2d 775, 786 (D.C. Cir. 1976) (same). As noted above, EPA is well within its authority to set standards that are technology-forcing and forward looking, and in the interests of long-term environmental benefit.

While section 111 does not permit EPA *to require the application* of any particular technological system of emissions reduction, nor does it mandate specific emissions reduction percentages, *see* 42 U.S.C. § 7411(b)(5); *Sierra Club,* 657 F.2d at 298, the NSPS emissions rates or limits must *reflect* the degree of emission limitation achievable through application of the best system of emission reduction, which the Administrator determines has been adequately demonstrated. *Sierra Club,* 657 F.2d at 298; *see also Portland Cement Ass'n v. Ruckelhaus* (*Portland I*) 486 F.2d 375, 391 (D.C. Cir. 1973). But "adequately demonstrated" does not mean that all existing sources are able to meet the new source standards, *see Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86, or even that the available technology be in active use in the industry at the time of the rulemaking. *See Portland Cement I*, 486 F.2d at 391. Rather,

> [t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.
> . . .
> [T]he question of availability is partially dependent on 'lead time', the time in which the technology will have to be available.
> . . .
> If actual tests are not relied on, but instead a prediction is made, 'its validity . . . rests on the reliability of [the] prediction and the nature of [the] assumption.

Portland Cement I, 486 F.2d at 391-92 (citing and quoting *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)).

The directive that EPA must take a forward looking approach in standard setting, and Congress's original particular interest in ensuring deep pollution reductions from the electricity sector, *see* S. Rep. No. 91-1196 (1970) at *16 (asserting intent that electrical generating plants must be controlled to the maximum possible degree), strongly supports Agency action that will in the long-term, result in deep reductions in CO_2 emissions. EPA can (and to be consistent with Congressional intent, must) encourage emerging technologies through the form and structure of this standard. *Sierra Club v. Costle* 657 F.2d at 341, 346-47. In the present situation, moreover, EPA must also look beyond this standard to the future if the U.S. is to do its part to avoid the worst environmental damage due to climate change. In short, EPA can and must encourage new and more effective and efficient control technologies through the standards it sets under section 111. Indeed, given the significance of the problem being addressed, and the robust EPA record here, final performance standards that are less protective than those EPA has proposed would not represent reasoned rulemaking.

B. While EPA Must Consider Costs, Exorbitance is the Standard – and The Agency is Authorized to Evaluate Associated Offsetting Revenue Streams, and the Social Cost of Carbon, in its Analysis.

The statute and case law authorize EPA not only to evaluate the costs of achieving the standard, but also any offsetting revenue streams, and to weigh the severity of the pollution problem to be addressed, in selecting missions control options comprising the "best" system of emission reduction.

1. EPA May Set a Standard For Which the Costs of Implementation are Not Exorbitant

Section 111(a)(1) directs EPA to "take into account" the cost of achieving reductions and any nonair quality health and environmental impacts and energy requirements when selecting the BSER and setting performance standards. 42 U.S.C. § 7411(a)(1). Over several decades, the D.C. Circuit has fleshed out the meaning of this directive, rejecting interpretations that would require the agency to conduct a traditional cost-benefit analysis. *See*, *e.g.*, *Essex Chem. Corp.*, 486 F.2d at 437 (acid mist standards were reasoned and cost-benefit analysis was not required); *Lignite Energy Council*, 198 F.3d at 930 (EPA did not exceed its discretion in setting boiler standards that modestly increased the overall cost of producing electricity). In *Essex*, the court held that EPA's standards must be "reasonably reliable, reasonably efficient, and . . . reasonably . . . expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way*." 486 F.2d at 433 (emphasis added). Similarly, in *Portland Cement Association v. Train* (*Portland Cement II),* 513 F.2d 506, 508 (D.C. Cir. 1975), the court interpreted section 111's cost inquiry as a safety valve to ensure that the costs an NSPS imposes are not "greater than the industry could bear and survive," but would instead allow industry to "adjust" in a "healthy economic fashion to the end sought by the Act as represented by the standards prescribed." And in *Lignite Energy Council*, the court held that "EPA's choice [of BSER] will be sustained unless the environmental or economic costs of using the technology are exorbitant." 198 F.3d at 933.

EPA also is authorized, in its analysis and standard setting, to look forward to the future and to "to weigh cost, energy and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Sierra Club v. Costle,* 657 F.2d. at 329-332 (discussing EPA's authority in setting standards to evaluate long-term growth, long-term environmental impacts, costs, and incentives for improved technology, and citing S. Rep. No. 95-127 (1977) and H. Rep. No.95-294 (1977) for the proposition that Congress itself took a long-term view in crafting section 111). EPA may "examine the effects of technology on a grand scale to decide what level of control [or emissions limit] is best." *Id.* at 330. This does not require the application of a strict cost-benefit test; rather, it simply allows analysis of the standards in light of the severity of the problem to be addressed, and the pollution reduction benefits they will yield. For example, in *Sierra Club*, 657 F.2d at 314, 327-28, the court upheld SO_2 standards that were projected to cost industry tens of billions of dollars between 1987 and 1995, but would provide significant benefits, including 100,000–200,000 tons of SO_2 emission reductions per year, health benefits valued at over $1 billion per year, and a 200,000 barrel-per-day reduction in oil consumption. This authority necessarily encompasses assessing the degree of harm to be prevented by the problem – that is the costs avoided in the longer term by the standard – in this instance, by a comparison with the Interagency Working Group social cost of carbon ("SCC").

As EPA correctly observes in the preamble to the proposed rule, the D.C. Circuit has never invalidated an NSPS as too costly. 79 Fed. Reg. at 1464. In *Portland Cement I*, the court upheld an NSPS for particulate matter emissions, even though control technologies amounted to roughly 12 percent of the capital investment for a new plant and increased total operating costs by five to seven percent. 486 F.2d 375, 387-88. Likewise, in *Portland Cement III*, the court upheld PM standards that were anticipated to increase the cost of cement by one to seven percent, with little projected decrease in demand. 665 F.3d at 191; *see also* 73 Fed. Reg. 34,072, 34,077, 34,086 (June 16, 2008). With respect to the electricity generating industry, the *Lignite Energy Council* court held that a two percent increase in the cost of producing electricity was not exorbitant or unreasonable*, see* 198 F.3d at 933 (citing 62 Fed. Reg. 36, 948, 36,958 (July 9, 1997)), and upheld the 1997 NO_x NSPS for EGUs and industrial boilers.

2. EPA Also May Take Into Account Byproduct Revenue Associated with a System of Emissions Reduction, in Considering the Costs Associated with a Standard Reflecting that System.

While the D.C. Circuit has yet to address directly whether EPA may take byproduct revenue associated with the choice of BSER into account in evaluating the costs of a performance standard, the court *has* held that the agency retains broad authority to weigh all of the statutory factors in a BSER determination, noting that questions of costs and benefits must be addressed taking a long-term perspective. *See Sierra Club*, 657 F.2d at 331. And, EPA's prior actions are consistent with the notion that byproduct revenue may be considered when the agency sets a performance standard. For example, in 2012, EPA and the National Highway Traffic Safety Administration finalized new fuel economy standards for light-duty vehicles. *See* 77 Fed. Reg. 62,624 (Oct. 15, 2012). In its cost analysis, the agencies determined that benefits resulting from more stringent standards would "far outweigh higher vehicle costs" to consumers, largely due to the 170 billion gallons of fuel that would be saved throughout the lives of vehicles sold over an eight-year period. *Id.* at 62,629, 62,631. From a macroeconomic standpoint, these savings are functionally indistinguishable from the revenue that would accrue if those 170 billion gallons of fuel were a direct byproduct of the new technology, rather than the amount saved due to reduced demand. Also in 2012, EPA analyzed revenues from the sale of natural gas and condensate recovered through the installation of pollution controls when describing costs associated with the NSPS for oil and natural gas production. *See* 77 Fed. Reg. 49,490, 49,534 (Aug. 16, 2012) (estimating that the proposed standards would save approximately $11 million annually if revenues from additional recovery were considered).

It is therefore well reasoned – wholly logical and appropriate – for EPA to consider revenue streams from the co-production of CO_2 (from the sale by the regulated power plant of captured CO_2 to an EOR operator for use and long-term containment in depleted oil or gas fields, *e.g.*) in evaluating the costs of a standard for which the underlying BSER includes carbon capture technology. As we discuss in detail in the Technical Appendix, EOR operations have for decades provided *de facto* containment of CO_2 from atmospheric release. To the extent that the CO_2 captured from an EGU is sold for use and eventual containment in EOR to satisfy the standards, the revenue from the sale is directly relevant to the cost of imposing the standard. Furthermore, as EPA notes, if costs of *disposal* of byproducts must be taken into account during cost analysis, *revenue* from the sale of economically valuable products as a co-benefit of achieving a particular performance standard also must be taken into account. *See* 79 Fed. Reg. at 1,464. In sum, to the extent that EOR is the expected mechanism by which long-term containment will occur, revenues from the sale of captured CO_2 should be considered in determining the proposed rule's costs.

3. EPA May Consider Subsidies and Subsidized Projects in Evaluating BSER.[7]

When evaluating a performance standard's projected costs, EPA may take into account the standard's long-term impacts on both a plant-wide and nationwide basis, including effects on the national economy. *See*, *e.g.*, *Sierra Club*, 657 F.2d at 331. And the legislative history affirms that the term "best technology" encompasses considerations of long-term growth, long-term cost savings, and financial incentives for improved technology. *See id.* (citing House and Senate reports). Subsidies that further encourage the commercialization of critical pollution abatement technology comport with the Clean Air Act's overall purpose, and the agency may generally consider such subsidies when determining the BSER underlying a performance standard. Indeed, EPA has done exactly this in the past. *See, e.g.*, 39 Fed. Reg. 9,308, 9310, 9311 (Mar. 8, 1974) (discussing cost of NSPS for petroleum refineries in light of an import license-fee program that created favorable conditions for domestic petroleum). That is a reasonable approach to the consideration of government funding meant to advance the market readiness, and adoption of pollution control technologies that provide real societal benefits. Government involvement provides reliable funding as well as greater certainty to equity investors and lenders while allowing the government access to the knowledge acquired, thereby driving down costs for the next generation of pollution control projects.

Arguments have been made, however, that EPA's proposed subpart Da standard violates an asserted prohibition on EPA's reliance on projects subsidized under the Energy Policy Act of 2005 ("EPAct05"). EPAct05 provided a 10-year authorization for the basic framework of CCS research and development at the DOE. 42 U.S.C. § 16293. Available subsidies include $2.2 billion already committed by the DOE for five CCS projects, and a DOE program in which $3.4 billion will be put towards up to ten integrated CCS demonstration projects, to begin operation by 2016. 79 Fed. Reg. at 1,479 (citing the Report of the Interagency Task Force on Carbon Capture and Storage (Aug. 2010) at 76).

EPA's Technical Support Document accompanying the NODA discusses these arguments and rebuts them as a legal and technical matter. See NODA TSD, EPA-OAR-HQ-2013-0495-1873. In any event as we discuss herein, EPA's proposed standard is amply justified on the basis of projects that are not subsidized under EPAct05.

CATF supports EPA's analysis of the relevant EPAct05 provisions as permitting EPA to consider the performance of EPAct05-supported projects in determining that a control technology is "adequately demonstrated," for the purposes of CAA section 111 standard setting,

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[7] CATF gratefully acknowledges the work done on this issue by Megan Ceronsky of the Environmental Defense Fund, *see* http://blogs.edf.org/climate411/2013/12/06/epas-proposed-carbon-pollution-standards-are-legally-and-technically-sound/, from which this section is liberally drawn.

so long as those projects are not the *sole* basis for that determination. That reading of the statute's text is most consistent with the purposes of the statute.

Specifically, EPAct05 sections 402(i) and 421(a) on their face only prohibit EPA from relying "solely" on EPAct-funded facilities in determining that a technology is adequately demonstrated. *See* 42 U.S.C. § 15962(i); *id.* §§13573(e), 13574(d). The prohibition therefore is limited to circumstances in which the Agency has no other evidence for its decision. Arguments that EPA cannot even include the facilities as part of a a much larger supporting record impermissibly write the term "solely" out of the statute.

EPAct05's tax code provisions are similarly worded, and similarly limited. Section 1307(b) states only that an EPAct-supported facility cannot be "considered to indicate" that a technology is adequately demonstrated. 26 U.S.C. §48A(g). But as EPA correctly notes, this provision could be read two ways: either as meaning that EPA cannot consider the technologies used at such a facility at all, or that they cannot form the *sole basis* for a determination that the technology is adequately demonstrated. Technical Support Document for the NODA (TSD) at 13. The latter is the best reading of the statutory language. If Congress had intended to entirely preclude EPA from even referring to facilities receiving a tax credit under EPAct05, surely it would have phrased that limitation far more clearly. Indeed, Congress knew how to draft such a prohibition when it wanted to. *Cf.* EPAct §227, 30 U.S.C. §1017(d) ("Any land that is subject to a unit agreement approved or prescribed by the Secretary under this section *shall not be considered in determining* holdings or control under section 7.") (emphasis added).

Moreover the tax statute should be interpreted together with the other text enacted at the same time and for the same purpose--there is no indication that Congress intended projects receiving tax incentives to be treated differently from projects receiving other kinds of federal support under EPAct05. *Cf. Erlenbaugh v. United States*, 409 U.S. 239, 245 (1972) (two statutes "intended to serve the same function" may be construed similarly to resolve any ambiguities). For all these reasons, EPA's understanding of section 1307(b) as simply preventing EPA from relying *exclusively* on EPAct-supported facilities in making a determination of whether a technology is adequately demonstrated is the most logical one.

EPA's interpretation of these EPAct05 provisions is also consistent with the purposes of both EPAct05 and the Clean Air Act. The enumerated statutory purposes and the legislative history of EPAct confirm EPA's conclusion that the provisions in question are intended "to encourage the development of technology so that it can be used on a widespread commercial basis."[8] TSD at 13. Indeed, the deployment of demonstrated, cutting-edge technologies to reduce

[8] Notably, the only technologies eligible for subsidy under the clean coal provisions of EPAct05 are exactly the kinds of pollution controls that the Clean Air Act is meant to promote: those that

harmful emissions is the purpose of section 111 performance standards. Prohibiting EPA from *ever* evaluating the performance of an EPAct-supported project, even when there is strong additional record evidence supports a determination that a technology is "adequately demonstrated," does not serve the goals of either statute.

Given that EPA's determination that CCS is adequately demonstrated does not rest primarily (much less wholly) upon the plants receiving support under EPAct05, that determination is legally sound. It is nevertheless clearly true that available cost subsidies further improve the reasonableness of the costs associated with the standard. Indeed, courts evaluating section 111 standards issued prior to EPAct05 recognized that the use of subsidies to support new and emerging control technologies is "not unusual." 79 Fed. Reg. at 1,479. Indeed:

> Each of the major types of energy used to generate electricity has been or is currently being supported by some type of government subsidy such as tax benefits, loan guarantees, low-cost leases, or direct expenditures . . . ranging from exploration to control installation. This is true for fossil fuel-fired; as well as nuclear-, geothermal-, wind-, and solar-generated electricity.

Id.

II. EPA Correctly Bases the Level of the Proposed Standard for New Subpart Da Fossil Fuel-Fired Boilers and IGCCs on the Application of Partial Carbon Capture and Sequestration as the Best System of Emission Reduction.

EPA proposes to set an emissions limit of 1,100 lb. CO_2/MWh on a gross electrical output basis for certain subpart Da utility boilers and IGCC units[9] based on the application of what it refers to as "partial CCS" – that is, CCS including CO_2 capture at less than 90 percent (gross basis). 79 Fed. Reg. 1,430, 1,467-77. EPA solicits comment on whether the emission limit may be more appropriately set at a different level and is considering a range of 1,000 to 1,200 lb. CO_2/MWh (gross),[10] and asks whether a lower standard is particularly appropriate if the

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"advance efficiency, environmental performance, and cost competitiveness well beyond" those currently in widespread commercial use. 42 U.S.C. § 15962(a).

[9] While subpart Da applies to new liquid oil- and gas- fired units, EPA appropriately emphasizes coal- and petcoke- fired units because no new utility steam-generating units designed to be fired primarily with liquid oil or gas have been built for many years and none are expected to be built in the foreseeable future due to the significantly lower costs of building Subpart KKKK combustion turbines. 79 Fed. Reg. 1,430, 1,468 n. 175. *Id.*

[10] These standards should be set on a net-output basis for the reasons explored in depth in Section X of the Joint Environmental Comments also filed today in this docket.

proposed 84-month compliance alternative is chosen by a power plant developer/owner. *Id.* at 1,468, 1,482.

As discussed above, EPA is required under section 111 of the Clean Air Act to set standards based on application of the *best* system of emission reduction, *see Sierra Club v. Costle*, 657 F.2d at 329-332, 346 n.174 (*citing* H.R. Rep. No. 95-294, 95th Cong. 1st Sess. 189 (1977)). For those new subpart Da sources that are expected to be constructed between now and 2022, EPA's record amply establishes that integrated CCS systems are now, and will be available for commercial application on coal-fired power plants, and that the component elements of these systems have been in long-standing use in other similar industrial applications in the U.S. and abroad. U.S. EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, EPA-452/R-13-003 at 4-12 – 4-14 (Sept. 2013) [hereinafter "RIA"]; *see also* U.S. EPA, "Technical Support Document: Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs" at 4 (Feb. 6, 2014), Docket ID No. EPA-HQ-OAR-2013-0495-187 [hereinafter "NODA TSD"]. *Cf. Lignite Energy Council*, 198 F.3d at 934, n.3 ("EPA may extrapolat[e]…a technology's performance in other industries," and look beyond domestic facilities to those used abroad). While EPA's record accompanying the proposal and in the NODA, is robust and sufficient to support the standards the Agency proposes,[11] there are many more examples of domestic and international projects that offer further support, and several recent reports and articles documenting current status of these projects – published since EPA's proposed rule was signed – that the Agency should include as support for its final standards.[12]

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[11] It bears re-emphasis that the subsidies provided for certain clean-coal technology projects under the Energy Policy Act of 2005 ("EPACT 2005") do not undermine EPA's current determination that carbon capture and sequestration technology is adequately demonstrated for the purposes of section 111 standard setting. EPA did not "solely" rely on EPACT 2005 subsidized projects in making its determination, rather the BSER determination stands on an extensive record of other projects and a long history of experience with the component technologies of carbon capture and sequestration. *See* Comments of Environmental Defense Fund On Notice of Data Availability (NODA) in Support of Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 10,750 (Feb. 26, 2014), *submitted to* EPA-HQ-OAR-2013-0495 (May 9, 2014) at 2-6.

[12] EPA continues to rely on now-four-year-old reports from the Interagency Task Force on Carbon Capture and Storage, (co-chaired by the DOE and the EPA), which found as early as 2010, that "although early CCS projects face[d] economic challenges *related to climate policy uncertainty*, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies, there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions." 79 Fed. Reg. at 1471 (*citing Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 2010)) (emphasis added); *see also* Pacific Northeast National Laboratory, *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*

In the Technical Appendix accompanying these comments, we describe the current status of integrated CCS projects on power plants, and in other industrial applications in the U.S. and around the world, and then collect and describe the current status of projects employing each of the component technical elements of CCS – capture, compression, transportation, and injection – whether for EOR or sequestration in depleted oil and gas fields or deep saline geologic formations. This record provides further support for EPA's determination that CCS systems are adequately demonstrated to support the proposed performance standard.

Encouraging the rapid expansion of CCS systems, including pipeline buildout and saline sequestration facilities – can enable near zero carbon emissions from new fossil burning plants now, and in the future can serve retrofit capture and sequestration on existing power plants. As discussed above, that goal is well within EPA's authority to consider in setting these technology-forcing, forward-looking standards. And, it is prudent public policy, as the expanded availability of CCS systems is imperative if the U.S. is to continue reliance on fossil fuel fired power plants for electricity production, given climate pollution reduction needs and goals. EPA's emphasis in its record, on the ongoing *de facto* long-term containment of CO_2 in EOR operations, is important in this regard. Numerous studies cited in our Technical Appendix point to EOR as an essential part of a widely available near term system for transportation and sequestration of CO_2.[13]

A. EPA Properly Relies on the Clean Air Act's Greenhouse Gas Reporting Program Subpart RR Monitoring, Reporting and Verification Plan to Verify that the CO_2 Captured from an Affected Unit is Injected Underground for Long-Term Containment

A national regulatory framework for underground injection of CO_2 and the airside monitoring and reporting of CO_2 emissions now exists to support a determination that CCS is the best system of emissions reduction for any industry using that technology. The Underground Injection Control ("UIC") Program under Part C of the Safe Drinking Water Act requires EPA to promulgate regulations containing minimum requirements to prevent underground injection,

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(June 2009), *available at*: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18520.pdf). We concur that these references and others relied on by the Agency are adequate to show that CCS technologies are the BSER for coal-fired power electricity generation, however there has been a great deal of progress since 2009-2010 in this area. Indeed, there has been a 50 percent increase in the operation and construction of integrated CCS projects just since 2011, according to the Global CCS Institute. *Global Status of CCS 2014* at 3.

[13] *See generally* Technical Appendix at Sec. IV (citing *e.g.* Hill, *et al*., *Geologic carbon storage through enhanced oil recovery,* 37 **Energy Procedia** 6,808, 6,811 (2013) (Ex. App. – 73) *available at*: http://www.sciencedirect.com/science/article/pii/S1876610213008576).

which endangers drinking water sources. 42 U.S.C. § 1421. In 2010, EPA established an injection well class specifically designed for the injection of CO_2 for geologic sequestration.[14] *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells,* 75 Fed. Reg. 77,230 (Dec. 10, 2010). A UIC Class VI well must be designed so that injected CO_2 remains contained underground in a manner that does not endanger drinking water supplies. *See* 40 C.F.R. Part 146 Subpart H. EPA has issued multiple guidance documents for Class VI wells that cover a variety of topics including monitoring and testing, site characterization, area of review evaluation and corrective action, well construction, and financial responsibility.[15]

Additionally, CO_2 injected for EOR[16] operations can be permanently stored in the underground oil (or gas) reservoir from which the recovered oil (or gas) is removed. Safe Drinking Water Act UIC Class II injection permits are required for injections of CO_2 for EOR.[17] If the primary purpose of the injection shifts from oil and gas production to sequestration of the carbon dioxide, and if there is an associated increased risk to USDWs compared with Class II operations, as determined by the state agency for states with primacy, or by EPA, then a Class VI permit is required. *See* 40 C.F.R. § 144.19.

The practice of CO_2 injection, whether for geologic sequestration under a UIC Class VI permit, or for business as usual EOR operations under a UIC Class II permit also requires reporting under EPA's Clean Air Act Greenhouse Gas Reporting Rule.[18] For business as usual EOR operations with Class II permits, that reporting is done pursuant to regulations found at 40

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[14] Under the SDWA UIC regulations, the term "geologic sequestration" is defined as "the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport." 40 C.F.R. §§ 144.3; 146.81.

[15] *See* EPA, Geologic Sequestration Guidance Documents (available at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm) (collecting links to EPA guidance documents for the Class VI well program).

[16] "Enhanced oil or gas recovery" is defined as: "…the process of injecting a fluid (e.g., water, brine, or CO_2 into an oil or gas bearing formation to recover residual oil or natural gas. The injected fluid thins (decreases viscosity) and/or displaces extractable oil and gas, which is then available for recovery. This is also used for secondary or tertiary recovery." 75 Fed. Reg. 77,230, 77,231 (Dec. 10, 2010).

[17] 40 C.F.R. § 146, subpart C.

[18] EPA finalized this aspect of the GHG Reporting Rule, *Mandatory Reporting of Greenhouse Gases*, 75 Fed, Reg. 75,060 (Dec. 1, 2010), under the authority of the Clean Air Act at the same time as it finalized the UIC Class VI rule.

CFR subpart UU. 40 C.F.R.§ 98.470-98.478. Under subpart UU, operators are required to report the mass of CO_2 received and the source of that CO_2, but are not required to calculate and report the amounts that are contained long term in the oil or gas reservoir in which they are injected. 40 C.F.R. § 98.472. However, where EOR operators opt to conduct long-term containment of CO_2, as a primary purpose of their Class II permitted operations, either during or after concluding the production of oil or gas, monitoring and reporting must occur pursuant to the regulations found at 40 CFR subpart RR, 40 C.F.R. §98.440 *et seq.* (2012) (Geologic Sequestration of Carbon Dioxide). Subpart RR requires any well, or group of wells, at which a CO_2 stream is injected for long-term containment in subsurface geologic formations to report the amounts of CO_2 received, injected, produced, emitted by surface leakage and sequestered in subsurface geologic formations. Subpart RR also requires the development and implementation of a Monitoring Reporting and Verification ("MRV") that includes delineation of monitoring areas, identification of potential surface leakage pathways for CO_2, and the likelihood, magnitude and timing of any leakage through these pathways, a strategy for the detection and quantification of any surface leakage, and a strategy for the establishment of baselines for monitoring surface leakage. 40 C.F.R. §§ 98.448 (describing MRV plan); and 98.444-447 (describing reporting and records retention requirements).

The Safe Drinking Water Act UIC Class VI permit requirements, coupled as they are with reporting pursuant to the CAA Subpart RR rules, establish a framework for protecting underground sources of drinking water ("USDW") and for accounting for the fate of the injected CO_2 with respect to sequestration from atmospheric release.[19] For long-term containment occurring incidental to or in addition to EOR operations, a UIC Class II permit and the CAA subpart RR rules establish a similar framework. In the near term it is highly likely that EOR will be used to isolate captured anthropogenic CO_2 from atmospheric release. It is therefore important for the EGU operator subject to this rule, be able to demonstrate that captured carbon dioxide is sent either to a Class VI geologic sequestration facility or to a Class II EOR facility reporting under subpart RR.

1. EPA's Intention to Require Any New Fossil Fuel-Fired Boilers or IGCC Employing CCS to Meet the Standard to Send Captured CO_2 Only to a Facility that Reports Under Subpart RR is Reasonable.

The EPA is proposing in the preamble text that "any affected unit that employs CCS technology which captures enough CO_2 to meet the 1,100 lb./MWh standard must report under

[19] EOR using mined natural CO_2 presents the same risks of CO_2 to atmospheric release, as does the use of captured CO_2 from a power plant. For that reason, and because there are no significant economic or technical impediments to requiring all EOR activity to report using subpart RR, we urge EPA to revisit the UU v. RR distinction, in the context of its reporting rules, and require RR reporting for all enhanced oil recovery activity permitted under UIC Class II.

[subpart RR],” if the CO_2 is injected onsite. 79 Fed. Reg. 1430, 1483 (Jan. 8, 2014). And if the captured CO_2 is sent offsite, then “the facility injecting the CO_2 underground must report under 40 CFR part 98 Subpart RR.” *Id.* EPA notes that the “practical impact” of these requirements would be that owners and operators of projects injecting CO_2 underground that are permitted under UIC Class II and that receive CO_2 captured from EGUs to meet the proposed performance standard will also be required to submit and receive approval of a Subpart RR MRV plan and report under Subpart RR.”[20]

The text of the rule, however, must be amended in order to clearly establish this as an enforceable requirement. Specifically, EPA proposes new 60 C.F.R. § 60.46Da(h)(5):

> If your affected unit uses geologic sequestration to meet the applicable emissions limit, you must report in accordance with the requirements of 40 CFR Part 98, subpart PP and either: (i) if injection occurs onsite, report in accordance with the requirements of 40 CFR Part 98, subpart RR, or (ii) if injection occurs offsite, transfer the captured CO_2 to a facility or facilities that reports in accordance with the requirements of 40 CFR Part 98, subpart RR.

See 79 Fed. Reg. at 1505. We understand (from the preamble discussion described above) that EPA means, by using the term “geologic sequestration” in the regulatory text, to refer to any kind of sequestration, whether by injection into a Class VI permitted well or by injection for enhanced oil recovery via a Class II permitted well. However, as noted above, the term “geologic sequestration” actually is a defined term in the Safe Drinking Water Act UIC program context that is limited to CO_2 injection for the primary purpose of long-term containment from the atmosphere, and does not encompass CO_2 injection for the primary purpose of enhanced oil recovery, even where incidental long-term containment of the injected CO_2 occurs as a result of that EOR activity.

If the rule is to accomplish EPA’s stated objective that at this time *all* captured CO_2 must be managed by injection underground (whether in a Class VI well, or incidental to Class II (permitted EOR activity), an amendment to the proposed rule text is required. We suggest amending proposed 60 C.F.R. § 60.46Da(h)(5) as follows:

> If your affected unit captures CO2 to meet the applicable emissions limit, your affected unit must use either (i) onsite or offsite geologic sequestration, pursuant to a permit issued under Class VI of the Safe Drinking Water Underground Injection Program, and that reports in accordance with the requirements of 40

[20] This is also consistent with the requirements of section 45Q of the Internal Revenue Code, which requires that taxpayers claiming the credit for sequestration must report under 40 CFR part 98 subpart RR.

C.F.R. Part 98, subpart RR," or (ii) send the captured CO2 for use in enhanced recovery of oil or natural gas, through injection permitted under Class II of the Safe Drinking Water Act Underground Injection Program for that purpose and that reports in accordance with the requirements of 40 C.F.R. Part 98, subpart RR.

Additionally, the requirement that the emitting EGU assure that captured CO_2 is managed at an entity subject to Subpart RR of the GHG reporting rules is exclusively an element of enforcement of the EGU standard. *Id.* at 1484. But as proposed, EPA's rule text does not impose any additional requirements on the affected facility to demonstrate that the CO_2 has in fact been transferred to a facility that is compliant with Subpart RR, that would be incorporated for example into its PSD and Title V permits for the facility. *Id.* EPA requests comment on whether additional requirements are necessary and what they may include. *Id.* We assert that EPA must require any EGU meeting the standard through long-term containment in a subsurface geological formation (either through geologic sequestration or in enhanced oil recovery), to provide documentation showing that the volume of captured CO_2 necessary to achieve the standard has been injected onsite to a facility permitted under the UIC program and reporting under Subpart RR, or transferred to a facility that is permitted under the UIC program and reports under Subpart RR. That documentation must be included with its compliance monitoring reports. The requirement to include this documentation should be added to proposed 40 C.F.R. §6060.46Da (h) and (i) concerning the submission of reports and recordkeeping requirements. Additionally, as it is a necessary part of the documentation of the achievement of the emissions standards, such reporting must become a condition of the Title V permit for the facility. 42 U.S.C. §7661c(a).

We also suggest the following amendment to subpart PP of the Clean Air Act reporting requirements, specifically to proposed new 40 C.F.R. § 98.426(h), as follows:

> § 98.426 Data reporting requirements.
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> * * * *
>
> (h) If you capture a CO2 stream from an electricity generating unit that is subject to subpart D of this part you must *transfer the captured CO2 to a facility or facilities subject to subpart RR of this part,* and you must:
> (1) Report the facility identification number associated with the annual GHG report for the subpart D facility,
> (2) Report each facility identification number associated with the annual GHG reports for each facility to which CO2 is transferred, and
> (3) Report the annual quantity of CO2 in metric tons that is transferred to each facility.

Finally, we note that some EOR operators have asserted that requiring compliance with the reporting and MRV plan requirements of subpart RR would result in operators avoiding the purchase of captured CO_2. We do not agree.

First, it is not inconsequential that available sources of naturally mined CO_2 are declining, and that there is therefore a significant demand for anthropogenic CO_2 in this industry.[21] Specifically, a 2012 analysis found that the economic demand is for 25 billion metric tons of CO_2, as compared with current available volumes of about 3 billion metric tons from natural resources, and existing natural gas processing facilities.[22] The additional anthropogenic CO_2 supply is estimated to represent a $1 trillion market (less costs of CO_2 transportation). It seems unlikely that existing operators would prefer to go out of business rather than access this market, simply because of the need for better reporting of the amounts of CO_2 managed in EOR activity.

Second, the costs of opting in to Subpart RR reporting by an existing EOR operator with a Class II permit are simply not significant, particularly when compared to the potential revenue from the sale of the produced oil, a calculation EPA performed in the Economic Impact Analysis for the Subpart RR rules. See 75 Fed. Reg. 75,060, 75,072-75,074 (Dec. 10, 2010) & Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Subpart RR: Proposed Carbon Dioxide Injection and Geologic Sequestration Reporting Rule, EPA-HQ-OAR-2009-0926-0830 §§ 4.5-4.10, 5.3-5.4, Tables 5-8 & 5-9. When EPA compared the average annualized costs of meeting the RR requirements at an EOR field with a Class II UIC permit, to the estimated revenue per field, the resulting "cost/sales ratio" ranged from 3.1-4%. *Id.* § 5.4, Tables 5-8 & 5-9. The cost per field is estimated to be on the order of $2 million dollars per year for the full monitoring and reporting program. As compared not just with the expected revenue to the operator, but also the cost to the environment of unmonitored, unreported (and therefore unknown and unchecked) CO_2 leakage to the atmosphere, this cost is reasonable.

B. The Costs of EPA's Proposed Subpart Da Standards are not Exorbitant

The costs of achieving EPA's proposed performance standard for new subpart Da units, including effects on the levelized cost of electricity ("LCOE"), are discussed below. In brief, EPA's standard meets the D.C. Circuit's test– they are not "exorbitant" when evaluated in terms

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[21] *See* V. Kuuskraa, Advanced Resources International, Inc.,"Using the Economic Value of CO2-EOR to Accelerate the Deployment of CO2 Capture, Utilization and Storage (CCUS)," in *Proceedings from the 2012 CCS Cost Workshop, Global CCs Institute* (April 25-26 2012) at slide 9, *available at* http://cdn.decarboni.se/sites/default/files/publications/100356/proceedings-2012-costs-workshop.pdf.

[22] *Id.*

of the resulting cost of electricity, or as compared with the social cost of carbon. And, where EOR is used for long-term containment of the captured CO_2, the revenues from the sale of CO_2 (or in some cases other co-produced commodities, such as urea produced in coal gasifiers),[23] dampen the cost impacts of the standard. CCS, moreover is clearly the most cost-effective CO_2 control option for subpart Da units burning coal for electricity production, as it can enable near zero CO_2 emissions: even EPA's proposed partial CCS approach achieves CO_2 emissions reductions from coal plants sufficient to make them comparable with subpart KKKK natural gas combined cycle turbines. EPA's careful consideration of the cost, energy, and non-air quality, environmental impacts of CCS satisfy the statutory requirements for the Agency to balance these required statutory factors in designating a CAA section 111 BSER.

EPA's proposal "serve[s] the interests of pollution control without becoming exorbitantly costly," *Essex Chem. Corp.*, 486 F.2d at 433. First, when designed into new facilities at a level of capture and sequestration that produces CO_2 emissions equivalent to those from a new combined cycle natural gas plant, the levelized cost of CCS is competitive with construction of other new low-carbon power plants. Second, the availability of implementation flexibility, the opportunity for revenue from the sale of the captured CO_2 for EOR purposes, and even the availability of subsidies make the costs of EPA's standard based on partial CCS even more reasonable. Third, partial CCS is cost-effective, and responsive to the need to promote deep, immediate reductions on CO_2 – it is the only currently available demonstrated control option that allows near zero carbon energy production from fossil fuels.

1. **EPA's Standard Does Not Produce Unreasonable Levelized Cost of Electricity Impacts**.

In the current proposal, EPA determined that its standard would result in negligible costs by 2022 because EPA's modeling showed that *even in the absence of the GHG rule*, new generation technologies (such as subpart KKKK natural gas combined cycle combustion turbine baseload facilities) would be chosen instead of coal-fired plants.[24] RIA at 5-1. Such new

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[23] Some IGCC plants co-produce electricity for sale and other commodities. *See e.g.* Texas Clean Energy Project discussed at Technical Appendix Sec. (I)(a)(i)(7).

[24] EPA also made this point in its original 2012 proposal for performance standards for CO_2 emissions from this industry. 75 Fed. Reg. 22,392 at 22,430 (Apr. 13, 2013). More recent public statements by industry spokespeople support this conclusion. *See*, *e.g.*, "'We don't have any plans to build new coal plants. So the rules won't have much of an impact. Any additional generation plants we'd build for the next generation will be natural gas.' American Electric Power, 3/26/2012, National Journal; 'As we look out over the next two decades, we do not plan to build another coal plant. ... As the evidence is coming in, [shale gas] is proving to be the real deal. If we have no plans, as one of the largest utilities and largest users of coal in this country, no plans to build a new coal plant for two decades, the regulations are not relevant.' Jim Rogers (Duke), 3/27/2012, NPR All Things Considered..;" RIA at n. 31.

generation technologies would meet the proposed standards without any additional capital expenditures or operating costs and, therefore, without any increase in electricity costs. *Id.* While the LCOE for new coal-fired generation that includes partial CCS is more than constructing coal plantswithout CCS, or new natural gas-fired generation, it is competitive with new construction of other low-carbon electricity generating power plants, including nuclear, the principal other option considered for baseload electricity generation. 79 Fed. Reg. at 1,477, RIA at Fig. 5-8.

The impact of a standard on the LCOE is a factor that EPA can consider in evaluating a standard's cost, consistent with the D.C. Circuit's precedent. *See, e.g. Portland Cement III*, 665 F.3d at 191 (upholding standards based on EPA analysis of commodity price increases of one to seven percent; 73 Fed. Reg. 34,072, 34,077, 34,086 (June 16, 2008)); *Lignite Energy Council,* 198 F.3d at 933 (citing 62 Fed. Reg. 36, 948, 36,958 (July 9, 1997) and holding that a a two percent increase in the cost of producing electricity due to application of NOx standards was not exorbitant or unreasonable).

LCOE is an economic assessment of the cost of electricity from a new generating unit or plant, including all costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital. Table 1, taken from EPA's proposal, compares the LCOE for various choices of electricity generating technologies, under several scenarios.

Table 1: LCOE per unit (2011$)[25] Adapted from 79 Fed. Reg. 1,477, Table 7.

Unit	Technology[26]	LCOE ($/MWh)
NGCC	@ $6.11/MMBtu	59
	@ $10.0/MMBtu	86
SCPC	w/o CCS	92
	1,100 lb/MWh; no EOR	110
	1,100 lb/MWh; low EOR	96
	1,100 lb/MWh; high EOR	88
	Full, 90% CCS	147
IGCC	w/o CCS	97
	1,100 lb/MWh; no EOR	109

[25] 79 Fed. Reg. at 1,476-77. LCOE is the annualized capital cost spread over the annual output of the generation facility. Costs are based on a capacity factor of 0.85 and include initial investment, operations and maintenance, cost of fuel, cost of capital, and a 3% increase to the weighted average cost of capital to reflect EIA's climate uncertainty adder. Costs do not factor in subsidies.

[26] Low EOR is based on an EOR price of $20/ton CO_2. High EOR is based on an EOR price of $40/ton CO_2.

	1,100 lb/MWh; low EOR	101
	1,100 lb/MWh; high EOR	97
	Full, 90% CCS	136
Nuclear	103–114	
Geothermal	80–99	

EPA's analysis comparing the proposed standard with the costs of other potentially very low carbon baseload technologies shows that even without a market for the captured CO_2, coal-burning subpart Da plants will have a LCOE of $109-110/MWh. This is cost competitive with the LCOE for new nuclear energy plants ($103-114/ MWh). Nuclear energy is the primary zero-carbon baseload electricity-generating source, providing 19 percent of net generation in the U.S. in 2012 and therefore serves as a proper comparison for subpart Da coal-burning baseload facilities with partial-CCS.[27] Partial CCS with low EOR price[28] ($96–101 /MWh) would make the LCOE of coal plants with partial CCS competitive with geothermal ($80–99/MWh). Moreover Table 1 also shows that the incremental LCOE for partial CCS (low EOR) as compared with new natural gas combined cycle units represents a range between $24-50, depending on the assumed price of natural gas. And comparing the LCOE of coal plants with CCS to the LCOE associated with uncontrolled new coal plants shows incremental costs of $18/MWh to -$4/Mwh for SCPC units – so, where EOR revenue is considered, even negative costs. These ranges also are comparable to or below the most recent SCC. *See* Interagency Working Group on Social Cost of Carbon, "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866" at 3 (Feb. 2010).

The SCC allows agencies to evaluate the social benefits of reducing CO_2 emissions in

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[27] U.S. EIA, *Electric Power Annual, Table 3.1.A. Net Generation by Energy Source: Total (All Sectors), 2002 – 2012* (Dec. 2013), *available at:* http://www.eia.gov/electricity/annual/html/epa_03_01_a.html; see also Hannah Northey, "Expect many energy loan commitments to close this year – Moniz," E&E News (Apr. 23, 2014)(reporting that in April U.S. DOE finalized $6.5 billion worth of loan guarantees to support construction of the two Vogtle nuclear reactors in Georgia), *available at*: http://www.eenews.net/eenewspm/2014/04/23/stories/1059998343; David Conti, "Nuclear Power Under Siege, FirstEnergy Exec Warns," **Pitt. Trib. Rev.** (Apr. 9, 2014)(reporting that Westinghouse is building four of its AP1000 reactors in South Carolina and Georgia in addition to plants in China and elsewhere), *available at*: http://triblive.com/business/headlines/5911059-74/nuclear-plants-sena#axzz2zpcLSOjM.

[28] The high EOR opportunity assumes a CO_2 sale price of $40 per metric ton; the low EOR opportunity assumes a CO_2 sale price of $20 per metric ton. RIA at 5-30.

making decisions about regulatory actions.[29] The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. *Id.* The figure includes, but is not limited to, changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. *Id.*

Table 2: 2020 Incremental Benefits using the Social Cost of Carbon ($/MWh, 2011$) of Emission Reductions from Coal-Fired Generation with CCS meeting 1,100 lbs/MWh Relative to New Coal-Fired Generation Without CCS, Source: RIA at 5-46.

	SCPC	**IGCC**
CO_2-Related Benefits Using SCC		
5% Discount Rate	$3.2	$2.1
3% Discount Rate	$11	$7.5
2.5% Discount Rate	$17	$11
3% Discount Rate (95th percentile	$34	$23

Table 2, above, shows that an SCPC plant with CCS and meeting a standard of 1,100 lbs/MWh, will produce $34/MWh of incremental societal benefits and an IGCC plant will produce $23/MWh of societal benefits, *see* RIA at 5-46, using the 3 percent discount rate and 95th percentile assumptions. Various Commenters support a discount rate of at least 2.5% and 95th percentile assumption, and that represents the potential for higher climate damages from uncontrolled emissions, and also greater climate/societal benefit from emissions controls.[30]

[29] Interagency Working Group on Social Cost of Carbon, "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866" at 1 (Feb. 2010).

[30] *See* Comment on FR Doc # 2014-01605**,** Clean Air Task Force, Docket ID: OMB-2013-0007-0097; Sierra Club, Docket ID: OMB-2013-0007-0083; Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, and Union of Concerned Scientists, Docket ID: OMB-2013-0007-0085.

2. Implementation Flexibility Offered In the Standards, and Revenue from the Sale of Captured CO_2, Mitigate the Costs of the Standard.

EPA's 2012 proposal included a 30-year compliance pathway – under which for the first 10 years, a new affected facility was held to a standard of 1800 lbs. CO_2/MWh (gross), and a standard of 600 lbs. CO_2/MWh (gross) was to be met beginning on day one of year 11, and thereafter, so that the controlled 1000 lbs. CO_2/MWhr standard would be met on average over 30 years from the beginning of facility operations.[31] That option provided considerable flexibility for developers of CCS-equipped facilities to make decisions about when to begin operating the capture and sequestration equipment, which allowed the costs associated with operating the CCS equipment to be deferred, and additional revenue generated in early years to offset the equipment costs. CATF's analysis showed that the 30-year compliance period offered fairly substantial cost benefit for an equivalent CO_2 emissions reduction.[32]

In the current proposal, new fossil fuel-fired boilers and IGCC units have the option to meet the NSPS on an 84-operating-month rolling basis. 79 Fed. Reg. at 1482; RIA at 1-3. The associated new emission limit will be between 1,000-1,050 lb. CO_2/MWh (gross). *Id.* This standard and the flexible compliance option yields effectively the same results as the 50 percent partial CCS case examined by NETL, and described in the CATF 2012 Costs Report as Case 1. The 84-month compliance option undeniably provides qualitative benefits, as it increases the operational flexibility of a plant – helpful in the earliest stages of facility operation and in the early years of the performance standard -- where the captured CO_2 is to be delivered offsite to sequestration that is not under the control of the power plant owner. The 84-month compliance option also minimizes the standard's effect on electricity prices to a certain extent beyond a requirement that the standard be met at day one of operations on a 12 month rolling average basis, but this benefit is unlikely to translate into the significant cost benefits associated with the

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[31] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources; Electric Utility Generating Units; Proposed Rule , 77 Fed. Reg. 22,392 at 22,436-22,421 (April 13, 2012).

[32] The Clean Air Task Force,"How Much Does CCS *Really* Cost? An Analysis of Phased Investment in Partial CO_2 Capture and Storage for New Coal Power Plants in the United States," 8, Figure 1 (compare Cases 3 and 3b with case 0). (White Paper, Dec. 20, 2012) *available at*: http://www.catf.us/resources/whitepapers/files/20121220-How_Much_Does_CCS_Really_Cost.pdf. [hereinafter "CATF 2012 Costs Report"].

former 30-year compliance alternative.[33] That is because it effectively requires a plant to achieve the standard fairly soon after starting operations.[34]

Revenue generated by the sale of captured CO_2 for use in EOR further reduces costs associated with the standard. For example, analysis done by CATF in support of the Agency's 2012 proposal, we showed that revenue from the sale of captured CO_2 for EOR lowers by $12/MWh, or approximately 10.33 percent the LCOE of applying a standard roughly equivalent to that currently proposed.[35] EPA properly considered this possibility. 79 Fed. Reg. at 1,464; RIA at 5-29 -5-31. This approach is consistent with that taken previously by the Agency. For example, in its 2010 rulemaking on greenhouse gas emissions limits for motor vehicles, EPA factored the fuel savings expected to result from reduced rates of vehicle fuel consumption into the assessment of the rule's potential costs – as an offset to the costs of the control requirement. 79 Fed. Reg. at 1,464 (citing 77 Fed. Reg. 62,624, 62628–29; 62923– 27; 62942–46 (Oct. 15, 2012) (rulemaking setting greenhouse gas emissions standards for Light-Duty Vehicles for Model Years 2017–2025)).

Although EOR sales are not now available everywhere, it is expected that any new coal-fired subpart Da unit would locate so as to take advantage of such revenue offsets to the cost of applying control technology to meet the standard. CO_2 is a valuable commodity both because of the limited volumes of naturally-sourced CO_2 in the U.S., and because of the increased demand for EOR activity as an energy security policy matter.[36] It is estimated that the next generation of EOR combined with the limited estimates of residual oil zone production could produce demand

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[33] CATF Personal Communication with Michael Fowler, ENE Services Group (Mar. 16, 2014). Mr. Fowler is one of the lead authors of the CATF 2012 Costs Report.

[34] *See* Joint Environmental Commenters discussion of monitoring, enforcement and compliance at Sec. XI.

[35] *See* CATF 2012 Costs Report at 7-8 and Figure 1. That study evaluated the costs of EPA's then-proposed standard including a 30-year compliance alternative, and also considered the cost impacts of accounting for the sale of captured CO_2 for EOR, using 2011 data on the costs of next-of-a-kind plants. EPA shows lower costs, as reported in Table 1 *supra* these comments at 21-22, using more recent data, but the cost differentials due to EOR revenue are similar: 4-9 percent depending whether CO_2 sales for EOR are assumed to be "high" or "low." And, as EPA properly notes in its proposal, 79 Fed. Reg. at 1476/1, these figures are useful for comparative purposes -- the details of any such cost analysis may differ from the quoted ranges.

[36] Bruce Hill, *et al*., *Geologic carbon storage through enhanced oil recovery*, 37 **Energy Procedia** 6808 (2013). CO_2 is currently very limited in supply with prices ranging from $15 to $40 per metric ton. *Id*. at 6811.

for approximately 33 billion tons of CO_2.[37] EOR operations in the U.S. can accommodate and provide long-term containment for substantial volumes of CO_2 as well as the cost-offsetting revenue attendant to the sale of the anthropogenic CO_2 by the EGU operator.[38]

3. The Standard Is Cost-Effective and Reasonable Because It Promotes Expanded CCS Providing Near-Zero Carbon Emissions, And Because System Expansion Would Lower Future Cost.

Because CCS technology can eventually reduce CO_2 emissions to near zero levels, additional costs in the interest of moving the technology forward are justified and reasonable. Notably, segments of the industry are already accommodating the costs of CCS on new coal plants, including by defraying the costs of sequestration with revenue from the sale of captured CO_2 to EOR operations. RIA at 5-29 (70% of the CCS projects under construction or at an advanced stage of planning intend to use captured CO_2 to improve recovery of oil in mature fields). Finally, it is relevant to the technology-forcing and forward looking aspects of section 111 standard-setting that the costs associated with CCS technology applications are expected to decrease over time.[39]

EPA appropriately recognizes that the construction and operating costs associated with CCS technologies will decrease as further experience with them is gained in response to the standard. 79 Fed. Reg. at 1477. *See also* RIA at 5-18, n. 38. This is supported by statements that SaskPower plans to retrofit additional units with CCS and expects the next retrofit will cost 30 percent less in capital costs and 20 percent less in operating costs.[40] And, EPA has in the past

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[37] Bruce Hill, *et al*., at 6814 (citing Vello Kuuskraa, Advanced Resources International, Inc. (2012). Using the Economic value of CO_2-EOR to accelerate the deployment of CO_2 capture, utilization and storage. (CCUS, EPRI Cost Workshop, Palo Alto, CA, April 25-26, 2012)).

[38] Bruce Hill, *et al*., at 6811.

[39] 79 Fed. Reg. at 1,477. *See also* RIA at 5-18, n. 38. Costs can be estimated for a "first-of-a-kind" (FOAK) plant or an "nth-of-a-kind" (NOAK) plant, the latter of which has lower costs due to the "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing research, development and demonstration projects. RIA at 5-18, n. 38.

[40] Graham Lanktree, "Nothing Ventured, Nothing Recovered: SaskPower's Boundary Dam Project a Test Case for Carbon Capture and Storage," CIM Magazine (Mar./Apr. 2014), *available at*: http://magazine.cim.org/en/2014/March-April/special-report/Nothing-ventured-nothing-recovered.aspx; *See e.g. also*, Meg Alexander, "Refrigeration Could Cool Down Costs of Carbon Capture and Storage," GizMag (Apr. 22, 2014), available at: http://www.gizmag.com/sintef-refrigeration-carbon-capture-storage/31718/. "New research by Scandinavian research organization Sintef has found that refrigeration technology may reduce costs [of CCS] by up to 30 percent, increasing the potential for faster implementation." *Id.*

considered the expected decline in pollution control costs in standard setting in other contexts.[41] For example, in setting mobile source air emissions limits, EPA considered decreasing costs of technology over time. 77 Fed. Reg. 62,624, 62,984-85 (Oct. 15, 2012).

For these reasons, as well as those articulated in the Joint Environmental Comments submitted today, we urge EPA to adopt the proposed new source performance standards for CO_2 emissions for subpart Da units.

Respectfully submitted,

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[41] *See* CATF 2012 Costs Report at 8 (Dec. 20, 2012) (concluding, among other things, that construction cost contingencies for CCS equipment will likely decrease over time); *See generally* Nicholas A. Ashford, et al., "Using Regulation to Change the Market for Innovation," 9 **Harv. L. Rev.** 419 (1985) (providing several examples of industry response to new regulation where the industry creates new technology and a market niche yet product change occurs rapidly as technology improves in order to compete on the basis of price). See also Margaret R. Taylor, et al., "Regulation as the Mother of Innovation: The Case of SO_2 Control" 27 **Law & Pol'y** 348 (Apr. 2005) (using the history of SO_2 control to show that increased diffusion of technology results in significant and predictable operating cost reduction in existing systems, as well as notable efficiency improvements and capital cost reductions in new systems).