BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF: STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FOR NEW STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE FOR SUBPART TTTT, 77 FED.REG. 22,392 (APRIL 13, 2012)	)	DOCKET ID NO. EPA-HQ-OAR-2011-0660

COMMENTS OF CLEAN AIR TASK FORCE AND CONSERVATION LAW FOUNDATION

Clean Air Task Force (CATF) and Conservation Law Foundation (CLF) appreciate the opportunity to comment on the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (GHG EGU NSPS). 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. Founded in 1966, CLF is a nonprofit, member-supported organization that works to solve the environmental problems threatening the people, natural resources and communities of New England. CLF's advocates use law, economics and science to design and implement strategies that conserve natural resources, protect public health, and promote vital communities in our region.

CATF and CLF congratulate the U.S. Environmental Protection Agency (EPA or the agency) for taking the first steps towards significant greenhouse gas emissions reductions from EGUs. As the agency recognizes, "[e]nergy-related CO_2 emissions are the largest contributor to total U.S. GHG emissions, representing 86.7 percent of 2009 [domestic] GHG emissions" and in 2009, the "electric power sector–consisting of those entities whose primary business is the generation of electricity–accounted for 40 percent of all [domestic] energy-related CO_2 emissions." 77 Fed. Reg. 22,403 (citing U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009," EPA Report No. 430-R-005 (April 15, 2011)).

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." *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 (Dec. 15, 2009) (hereinafter *Endangerment Finding*). These concentrations continue to increase. *See* NOAA Research Matters release,"NOAA: Carbon dioxide levels reach milestone at Arctic sites," (May 31, 2012), *available at* http://researchmatters.noaa.gov/news/Pages/arcticCO2.aspx (reporting that "[t]he concentration of carbon dioxide in the atmosphere of Barrow, Alaska, reached 400 parts per million (ppm) this spring…, the first time a monthly average measurement for [CO_2] attained the 400 ppm mark in a remote location.") (Attached as Exh. 1).

Changes to earth's climate (globally, regionally, and locally) resulting from CO_2 and other greenhouse gas emissions "have the potential to affect essentially every aspect of human health, society and the natural environment." *Endangerment Finding*, 74 Fed. Reg. at 66,523. Specifically, EPA projects multiple negative impacts on human health and welfare including but not limited to; (1) intensified and more severe heat and cooling waves that are associated with short-term increases in mortality, *id*. at 66,524-525; (2) increased regional ozone pollution, with associated risks of respiratory illness and premature death, *id*. at 66,525; (3) an increased spread of food and water-born pathogens causing waterborne diseases among susceptible populations, as well as an increased susceptibility to allergies, *id*.; (4) an increase of extreme weather events, as well as adverse impacts by increases in the severity of coastal storm events to sea level rising, leading to an increased risk of death and infectious respiratory, and skin diseases *id*.; (5) enhanced pest and weed growth which can lead to reduced crop production and economic loss, *id*. at 66,531; (6) likely increase in wildfires, insect outbreaks, and tree mortality, *id*. at 66,532; (7) adverse effects on water quality, including increased pollution and operating costs and reduced reliability, *id*.; and (8) direct losses associated with coastal flooding, *id*. at 66,534. Once emitted to the atmosphere, CO_2 persists for 100 years or more. *Id.* at 66,517 & n.18. These and other impacts predicted by the available science amply justify strong near-term actions to control greenhouse gas pollution on the basis that it threatens public health and welfare.

Recognizing this, President Obama has asserted that our nation must commit itself to the goal of cutting greenhouse gas emissions by roughly 17 percent by 2020, and by more than 80

percent by 2050. *See* President Barack Obama, Remarks at Morning Plenary Session of the U.N. Climate Change Conference (Dec. 18, 2009) (available at http://www.whitehouse.gov/the-press-office/remarks-president-morning-plenary-session-united-nations-climate-change-conference) (last viewed June 22, 2012) (Attached as Exh. 2). Given that Congress did not pass legislation to achieve that goal, the Administration necessarily has embarked on a program of GHG reductions relying on existing authorities in the Clean Air Act (CAA or the Act). *See Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards,* 75 Fed. Reg. 25,324 (May 7, 2010), *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 75 Fed. Reg. 31,514 (June 3, 2010), *see also* OMB, *Fiscal Year 2013 Budget of the U.S. Government*, at 178 (available at http://www.whitehouse.gov/sites/default/files/omb/budget/fy2013/assets/budget.pdf) ("the Administration continues to support greenhouse gas emissions reductions in the U.S. in the range of 17 percent below 2005 levels by 2020 and 83 percent by 2050") (last visited 6/24/2102).

The EGU GHG CO_2 NSPS therefore is a welcomed next step in implementing EPA's climate regulatory program under the CAA. Our comments describe the technology-forcing, forward-looking directive Congress included in CAA section 111, and explain why EPA's proposal to regulate all fossil fuel-fired EGUs under a new subpart TTTT is justified. We support a CO2 emission standard that is based on net electric output for this industry, but agree that the level and structure of the performance standard EPA has proposed are amply supported on the record before the Agency. Indeed, EPA could and should, given the significant problem of climate change and this industry's significant contribution to it, finalize a standard at the low-end of – or below – the proposed range. EPA can support the new source standards at this level based not only on natural gas combined cycle (NGCC) plants, but also based on carbon capture and sequestration (CCS) systems, as the "best system of emissions reductions" (BSER) for proposed new subpart TTTT. The case for CCS as BSER for this industry is particularly robust because of EPA's 30-year averaging compliance pathway for sources using this emerging technology. We provide the agency with additional studies and other information beyond that already in EPA's record for this proposal, and further demonstrating that CCS is available as a BSER for this industry. And we discuss why EPA's proposed broad exemption for "transitional sources" is both practically unnecessary and unjustified as a legal matter.

In short, our position is that there is no reasonable justification for additional development of new coal plants without CCS during the regulatory future for this rule (2012-2020). We strongly urge the Agency to finalize performance standards for new subpart TTTT reflecting an emissions rate at least as protective as that which was proposed, and based on both NGCC and CCS as the BSER for this industry. If EPA finalizes a transitional source exemption, it must be limited to those potential transitional sources already proposing to utilize CCS systems for CO2 control, as the record justifies an exemption, if at all, only for those sources. And we encourage the agency to issue with the final rule a projection of the "glidepath" towards even deeper reductions from this industry, both from the future reviews of the new source standards, and by making a commitment to the process of issuing standards for greenhouse gas emissions from existing sources in the industry.

I. Legal Principles: There Is No Barrier To EPA Issuing These Standards, Which Must Be Forward Looking and Technology Forcing.

A. The Agency Need Not Issue a new Endangerment or Cause or Contribute Finding Before Promulgating GHG Performance Standards for this industry.

EPA's proposal solicits comments on "whether section 111 includes prerequisites to rulemaking that involve an endangerment finding and a cause-or-contribute-significantly finding." 77 Fed. Reg. at 22,411/3. As an initial matter, we agree with EPA that nothing "require[s] the EPA, as a prerequisite to regulating any particular air pollutant, to issue an endangerment finding or a cause-or-contribute finding for that air pollutant from that source category." 77 Fed. Reg. at 22,397. The Administrator must list an industry for the purpose of developing performance standards "if in [her] judgment *it* causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. §7411(b)(1)(A) (emphasis added). The question of endangerment is analyzed with respect to the pollution, independent of the specific industry; the "cause or contribute" requirement under the NSPS program is associated with *the industry* at the time of its listing, not each time a new pollutant is identified that reasonably may be anticipated to endanger public health and welfare.

As EPA already has made a formal finding that the presence of six greenhouse gases including CO_2 and methane "in the atmosphere may reasonably be anticipated both to endanger public health and…public welfare," *Endangerment Finding*, 74 Fed. Reg. at 66,497, the agency need not reissue that finding with every further step it takes in controlling that air pollution. EPA's Endangerment Finding already has established that CO_2 is "air pollution which may reasonably be anticipated to endanger public health and welfare."

And all components of EPA's proposed new subpart TTTT are already regulated under the new source performance standards program. EPA in these listing decisions already has found that the sources in subpart Da, *see* 44 Fed. Reg. 33,580 (June 11, 1979), and subpart KKKK, *see* 71 Fed. Reg. 38,482 (July 6, 2006) cause or contribute significantly to air pollution that may reasonably be expected to endanger public health or welfare. Therefore, EPA must, when it periodically reviews performance standards for these listed industries, revise the standards as appropriate. The substantial GHG emissions from this industry make this an easy decision. Publicly available information about CO_2 emissions from fossil-fuel fired EGUs amply demonstrates that this industry causes or contributes significantly to GHG pollution, as EPA points out. 77 Fed. Reg. at 22,403/3. As noted above, the industry represented 40 percent of US energy sector CO_2 emissions in 2009, or almost 35 percent of total domestic anthropogenic CO_2 emissions. Clearly, EGUs "cause or contribute significantly" to U.S. total anthropogenic CO_2 emissions.

EPA suggests and seeks comment on "alternative interpretations," a scenario under which silence in the statute about the precise requirement of whether or not each pollutant requires a separate cause or contribute finding for each industry would then require the agency to make a "cause or significantly contribute" finding before issuing performance standards for those pollutants emitted by that industry. *See id.* at 22,412-413. We do not concede that the statute can be read to require a cause or contribute significantly determination each time the Agency considers regulations for an already listed industry. In any event, were such "alternative interpretations" required, it is clear that EPA's authority "is not a roving license to ignore the statutory text." *AEP v. Connecticut*, 131 S.Ct. 2527, 2539, --U.S. -- (2011) (quoting *Massachusetts v. EPA*, 549 U. S. 497, 533 (2007)). A determination not to regulate CO_2 emissions from fossil fuel-fired EGUs – representing 40 percent of U.S energy sector total emissions, and therefore obviously a significant contributor to U.S. domestic CO_2 emissions –

clearly would be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. §7607(d)(9)(A) (Clean Air Act standard for review).

Moreover, EPA's discretion under section 111 is not unfettered, as to the appropriateness of regulating and as to the details of promulgated standards for air pollutants emitted by the listed source category. The decision whether to regulate and what standards to issue for a pollutant emitted by a listed source category hinges on two factors: 1) the amount of emissions of the pollutant in question from that source category, and 2) the availability of demonstrated control measures to control or minimize it. *See National Lime Ass'n v. EPA*, 627 F.2d 416, 426 n.27 (discussing the appropriateness of EPA's decision to not propose NSPS for nitrogen oxides (NOx), carbon monoxide (CO) and sulfur dioxide (SO_2) emitted from lime plants).

EPA has consistently applied these two factors in previous section 111 rulemakings for criteria air pollutants. *See, e.g.*, 50 Fed. Reg. 36,959, 36,961 (Sept. 10, 1985) (EPA made a negative determination for regulating NOx and SO_2 from Portland cement plants based on lack of technology to control emissions); 75 Fed. Reg. 54,970, 54,994-95 (Sept. 9, 2010) (EPA determined NSPS for NOx and SO_2 were now appropriate because the emissions were significant and technology to control emissions was demonstrated). Additionally, the agency is not required to have absolute or even "ninety-five percent certainty in all the 'facts' which enter into an agency's decision." *Nat'l Lime*, 627 F.2d at 453-54 & n. 139 (*citing Ethyl Corp. v. EPA*, 541 F.2d 1, 28 n. 58 (D.C. Cir.), *cert. denied*, 426 U.S. 941 (1976)). Based on these considerations, and the record before the agency, EPA's decision to issue new source performance standards for CO_2 emissions from fossil fuel-fired EGUs is entirely justified. The industry emits 40 percent of the country's total energy sector CO_2 emissions, and as explained fully below, there are at least two control options offering significant CO_2 emissions reductions from this industry.

B. These Standards Must Be Forward Looking and Technology Forcing; They Must "Enhance Air Quality…Not Merely Maintain It"

The problem of climate change air pollution requires a significant response, beginning, as EPA has proposed, with the largest industrial contributors to the problem. That approach is consistent with Congress's intent as to how the Agency should prioritize its standard setting. *Cf.* 42 U.S.C. 7411(f)(2) (1977) (initial standard setting exercise to be prioritized beginning with largest emitters). EPA is completely within its authority to seek deep reductions based on the best available systems of emissions reduction for the industry – indeed Section 111 of the Clean

Air Act ("Act") *requires* EPA to set technology-based emissions limits for sources within "listed" categories. 42 U.S.C. §7411 *et seq.* EPA must set standards that reflect

> the degree of emission limitation achievable through the application of the <u>*best*</u> system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Id. §7411(a)(1) (emphasis added).

Furthermore, the purpose of the Clean Air Act, and the NSPS program in particular, is to enhance air quality, not merely maintain it. *See* 42 U.S.C. §7401(b)(1) (discussing purposes of the Clean Air Act); *see also ASARCO v. EPA*, 578 F.2d 319, 327 (D.C. Cir 1978) (same, specific to CAA section 111 performance standards: "[t]he New Source Performance Standards are designed to enhance air quality…."). To achieve this goal, performance standards must be based on "application of the *best system of emission reduction.*" 42 U.S.C. § 7411(a)(1) (emphasis added). *See also ASARCO*, 578 F.2d at 322 (A NSPS is "designed to force new sources to employ the best demonstrated systems of emission reduction"); *National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976) (discussing the components of the "standard of performance" definition, including BSER). This understanding dates back to the 1970 amendments, when the NSPS provisions were added to the Act. *See* S. Rep. No. 1196, 91st Cong. 2d Sess. 16, reprinted in Leg. Hist of CAAA of 1970, at 416 (1974)(stating that "maximum feasible control of new sources at the time of their construction [was] seen by the committee as the most effective, and in the long run, the least expensive approach."). And, Congress particularly focused its attention on the need to control power plant air pollution. *Id*. (directing EPA to establish new source standards for power plants).

To ensure the statutory goals are met, Congress designed the NSPS program "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less-costly systems to control air pollution" during the 8-year period before EPA must review the standard again. *Sierra Club v. Costle*, 657 F.2d 298, 347 & n.174 (D.C. Cir. 1981) (quoting Sen. Muskie's remarks, S.Rep. 95-127 at 18, L.H. at 1392). Both the emissions rate and the form (or structure) of the standard are within EPA's authority to define, in furtherance of this "technology forcing" idea, and in order to promote and satisfy the statutory goal. *Id.* To that end, both BSER and the standard based on BSER must "look[] toward what may fairly be projected for the

regulated future, rather than the state of the art at present…." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("*Portland Cement I*"). *See also Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (when setting standards, the NSPS program "does not require that a [source within the listed category] be currently in operation which can at all times and under all circumstances meet the standards…."). EPA furthermore (and as discussed more fully below) can explicitly base the level and the form of a performance standard on the degree to which it will encourage the development of emerging or innovative technologies that better control the air pollution in question – particularly where such a technology has significant future potential for emissions reductions. *Cf. Sierra v. Costle*, 657 F.2d at 341, 346-47 (upholding EPA's justification of a variable emissions standard set at a particular level in order to encourage the use of an emerging technology).

Because the technology or technique that is BSER need not be in routine use at the time EPA sets the standard, the question EPA must answer is whether such technology or technique is available for installation in new plants *over the regulated future*. *See, e.g., Lignite Energy Council v. EPA*, 198 F.3d 930, 933-34 (D.C. Cir. 1999) (upholding EPA decision to base the NSPS for utility boilers on a control technology that, at the time, had no performance data because the technology had been applied only to a similar industrial category). Moreover, when setting a standard based on a particular BSER technology or technique, EPA can "extrapolat[e]…a technology's performance in other industries", and look beyond domestic facilities to those used abroad. *Id.* at 934 n.3.

"It is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chemical*, 486 F.2d at 433. To be "adequately demonstrated," and therefore support an achievable emissions standard, BSER 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." *Id.* NSPS are meant to be rigorous, promoting significant emissions reductions, such that the inquiry is whether the costs of the standard are "greater than the industry could bear and survive," *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("*Portland Cement II*"). *See also* S. Rep. No. 91-1196, at 16 (1970), L.H. at 416 (the "implicit consideration of economic factors…should not affect the usefulness of this section", which is to "insure that new stationary sources are designed, built, equipped, operated, and maintained so as to reduce emissions to a minimum").

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 at *16 (asserting intent that electrical generating plants must be controlled to the maximum possible degree), support Agency action setting out a plan for long-term, deep reductions from this industry. 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. EPA has authority "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." *Id*. 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." *Sierra Club v. Costle,* 657 F.2d. at 330.

The 1977 Clean Air Act Amendments included the predecessor to BSER, defining "standards of performance," as based in part on "the degree of emission limitation achievable through application of the *best technological system of continuous emission reduction*…" 42 U.S.C. § 7411(a)(1) (1978). When Congress amended the Clean Air Act in 1990, a revised BSER requirement remained: "the degree of emission limitation achievable through the application of the *best system of emission reduction*…." 42 U.S.C. §7411(a)(1). Although since 1990, the statute no longer includes the requirement that the emissions reduction system underpinning the standard be "technological" or "continuous," the standards still must be based on the *best* available systems of emissions reduction, and the technology-forcing aspects of these provisions are maintained. *See, e.g., Lignite Energy Council,* 198 F.3d at 933-34 (EPA did not exceed its "discretion under section 111" by setting standards based in technology that was new to the industry and more expensive than the then-current control technologies).

And, the damage already being caused by uncontrolled climate pollution from this significantly emitting industry warrants EPA marshalling all of its resources towards the long view. Specifically, the Agency can set forth in the current final rule's preamble the

Administrator's commitment and intention to in the future satisfy the statute's requirement that she "shall, when revising the standards…consider the emission limitations and percent reductions [beyond those required by the standards] achieved in practice." 42 U.S.C. §7411(b)(1)(B). In so doing she can provide much needed direction -- a projected path to the deep reductions needed from this sector -- based on projections of the future emissions rates from the application of "best system[s] of emission reduction" likely to be available in future revisions to the standards. At the very least, EPA must include the Administrator's plan for a long term trajectory to reduce total CO_2 emissions from all fossil fuel fired power plants, in the rulemaking the Agency must undertake on existing sources under section 111(d).

C. EPA must also regulate CO_2 from existing sources.

As currently proposed, the GHG EGU NSPS covers only certain new sources. 77 Fed. Reg. at 22,436 (proposed 40 C.F.R. §§ 60.5509, 60.5510) (only non-transitional fossil fuel fired EGU sources commencing construction in U.S. continental areas after April 13, 2012 are subject to subpart TTTT). While this is a much needed step in ultimately reducing our nation's GHG emissions, this rule does not cover the largest contributor: existing fossil-fuel fired EGUs. As EPA acknowledges, and as noted above, existing sources in the electric power sector accounted for 40 percent of energy-related CO_2 emissions in 2009. *Id.* at 22,403/1. This equates to a total of 5,751.1 Tg CO_2e that is not required to be reduced under the proposed GHG NSPS – from existing coal-, oil-, and natural gas-fired EGUs. These substantial emissions figures make clear that unless *existing* sources within subpart TTTT are regulated, the long-term goal of reducing U.S. domestic GHG emissions by 80 percent by 2050 simply will be unattainable.

Clean Air Act section 111(d) requires EPA to "prescribe regulations which shall establish a procedure" like that for state implementation plans under section 110 of the Act, and also where a federal plan is necessary, to "promulgate a standard of performance under such plan," for existing sources to which a new source standard would apply. 42 U.S.C. § 7411(d)(1), (2). These standards can be set for any air pollutant for which no National Ambient Air Quality Standards (NAAQS) is set and no NAAQS process has been initiated, or which is not regulated as a hazardous air pollutant under CAA section 112. 42 U.S.C. §7411(d), *see also* 40 C.F.R. §60.21(a) (2012). Greenhouse gases are neither subject to ambient air quality standards, nor regulated as air toxics. Therefore, once EPA finalizes performance standards under section

111(b), the agency must set performance standards that existing sources in the industry must meet – whether or not they undertake major modifications. *Cf. AEP v. Connecticut*, 131 S.Ct. at 2530 (noting that "once EPA lists a[n industry] category, it must establish standards of performance for emission of pollutants from new or modified sources within that category, … §7411(b)(1)(B), and, most relevant here, must regulate existing sources within the same category §7411(d).").

Based on these principles, and as described in detail in Section III below, for EPA's new TTTT category, the level of the proposed standards is justified as achievable, not only based on the availability of efficient NGCC plants and currently abundant natural gas as BSER, but also on the current availability of carbon capture and sequestration (CCS) control technology. CCS is BSER even at and below the low end of the range of CO_2 emissions rates (950 pounds CO_2 per megawatt-hour (MWh) (gross)) on which EPA seeks comment. 77 Fed. Reg. at 22,406. In short, under the statute, EPA *could and should* issue much stronger standards than it has offered up for comment in this proposal – and certainly EPA's GHG EGU NSPS cannot reasonably be finalized at an emissions rate *less protective* than the proposed standards.

II. Combining Coal and Natural Gas Fired Power Plants in New Category TTTT Is A Reasonable Exercise of EPA's Discretion And Furthers Statutory Goals

A. EPA Is Authorized to Create New Subpart TTTT

The Clean Air Act *requires* EPA to consider and revise "from time to time" the list of source categories under the NSPS program. 42 U.S.C. § 7411(b)(1)(A). At such times, EPA "*may* distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." 42 U.S.C. §7411(b)(3) (emphasis added). That authority also includes the ability to create a combined category (new Subpart TTTT of 40 C.F.R. Part 60) for the purpose of issuing standards for CO_2 emissions, based on electric utility generating units that "serve the same function, that is to serve baseload or intermediate demand." *See* 77 Fed. Reg. at 22,398/3; *see also Lignite Energy Council*, 198 F.3d at 933 (finding it a reasonable exercise of EPA's authority to decide whether to subcategorize or to issue uniform standards for a single industrial subcategory). That is particularly so where EPA can identify BSER supporting the level of the standard as applied for the combined industry; here, not only NGCC, but also CCS technology is available as BSER for the combined industry. *See infra* Section III (discussing availability of CCS systems as BSER for coal and natural gas power plants) – while EPA's proposed standard does not *require* the use of CCS technology on natural gas plants, that technology is *available* now to achieve deeper CO2 reductions at those EGUs.

EPA has previously combined existing subcategories for regulation of specific pollutants, when exercising its authority to revise the industry list from time to time. As EPA notes in the proposal, 77 Fed. Reg. at 42,411/1, it has previously combined into one category, separate subparts containing sources that were baseload or intermediate load demand facilities. For example the Agency combined Integrated Gasification Combined Cycle (IGCC) units – previously regulated under subpart GG – with coal-fired EGUs, under subpart Da. *Compare* 40 C.F.R. §60.40Da(b) (2006) (describing affected facilities as, *inter alia*, facilities "burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average") *with* 40 C.F.R. §60.40Da(b) (2005) (noting gas turbine emissions – including those from IGCC – were subject to subpart GG). EPA also has previously created combined categories from former subcategories when updating performance standards for cement kilns, 75 Fed. Reg. 54,970,

55,500-512, 55,015 (Sept. 9, 2010)[1] (setting single standard for different kiln types), and for lime producers, 47 Fed. Reg. 38,832, 38,843 (Sept. 2, 1982) (one lime kiln standard independent of fuel).

New subpart TTTT is further justified because EPA has already found that the emissions from all of the potential affected facilities have the potential to cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. *See* 44 Fed. Reg. 33,580 (June 11, 1979) (establishing first NSPS for [electric utility steam generating units]), 44 Fed. Reg. 52,798 (Sept. 10, 1979) (establishing NSPS for stationary gas turbines), 71 Fed. Reg. 38,482 (July 6, 2006) (establishing new subpart KKKK for stationary combustion turbines, including combined cycle and simple cycle facilities). EPA is correct in noting that these previous listings are sufficient to trigger the duty to regulate GHG emission for the facilities covered under Subpart TTTT.

B. EPA Should Clarify That CHP EGUs and Simple Cycle Turbines Used More than 2000 Hours Per Year Are Subject to the Standards.

EPA's decision to include combined head and power (CHP) units meeting the definition of an EGU, under these standards is reasonable. It encourages more efficient energy production by avoiding a rush to building uncontrolled coal CHPs. For the same reasons, it is appropriate to include simple cycle plants that operate in intermediate or baseload use under the standards. We therefore cannot support EPA's proposal to exempt all simple cycle combustion turbines from the GHG EGU NSPS.

Under EPA's proposal CHP units will be subject to the proposed GHG performance standards if they meet the definition of an EGU (that is, if the unit supplies more than one third of its potential electric output capacity and more than 25 MW net-electric output to any utility power distribution system for sale). By the same reasoning, smaller CHP facilities are exempted from the proposed standards. 77 Fed. Reg. at 22,436/2, 22,439/2-3 (proposed 40 C.F.R. § 60.5509 and 60.5570 (definitions of CHP and EGU)). EPA seeks comment, however, on whether to exempt all CHPs with useful thermal output of at least 20 percent of the total useful output, even if they meet the definition of an EGU. EPA offers little if any supporting

[1] Upheld in *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 190-93 (D.C. Cir. 2011).

justification, simply asserting that exempting all such CHP units would "recognize the environmental benefit of CHP and result in additional installations that would otherwise no[t] occur." *Id*. at 22,431/2.

EPA then offers a parade of reasons *not* to finalize an expanded exemption covering EGU CHPs, and we agree it would be unreasonable if the agency did so. EPA notes that "if potential developers of new coal-fired generation opted … to build coal-fired CHP to avoid the CO_2 limitations proposed under today's rule, [that] could result in greater emissions of CO_2," and also that "building new coal-fired units to meet a standard of 1,000 lb CO_2/MWh would likely result in greater reductions [than would finalizing an exemption for large CHP units]." *Id.* We agree with the Agency on both of these points and therefore that finalizing an exemption for all CHP EGUs is not justified, nor would it be a reasonable exercise of EPA's discretion.

The environmental damage caused by a rush to build new uncontrolled coal CHP units to avoid the performance standards potentially would more than offset the benefits associated with using CHP technology. While there is some experience with a Danish coal-fired CHP source that achieves very deep CO_2 reductions,[2] that precedent will not become the norm in this country if CHP EGUs are *exempted from* the performance standard. The exemption would instead create incentives for a new generation of relatively uncontrolled coal plant development, which, while more efficient than current uncontrolled coal plants, would not have the potential to achieve in the near-term the very deep CO_2 emissions reductions that can be achieved by plants deploying CCS technologies.

Rather than providing a complete exemption, EPA should finalize the compliance method proposed for EGU CHPs, under which the CHP's total output – that is, measured by electrical output in MWh plus 100 percent of useful thermal output (in equivalent MWh) – plus a 5 percent surplus credit, to take into account reduced transmission and distribution losses, would be used to determine a CHP unit's compliance with the performance standard.

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[2] *See* Information about Dong Energy, a highly efficient coal fired CHP in Aalborg, Denmark, at http://www.dongenergy.com/SiteCollectionDocuments/NEW%20Corporate/PDF/Engineering/47.pdf

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EPA's proposal not to combine all of current subpart KKKK into the new subpart TTTT, instead exempting all "simple-cycle" combustion turbines from the proposed rule, *see* 77 Fed. Reg. at 22,411; 22,437 (proposed 40 C.F.R. § 60.5520(d)), is not reasonable, as it would create perverse incentives for development of these facilities for intermediate load demand and even baseload applications, in order to avoid the standards. While EPA asserts that these facilities *now* are used only for peaking purposes, not for intermediate load or baseload energy production, and so don't emit much CO_2, *id.* at 22,398, the agency does not demonstrate that this situation will *continue* if all simple cycle combustion turbines are exempted from the standard. The Agency seeks comment on this aspect of the proposal, and also on the alternative idea that an exemption might be justified only for units that do not meet the definition of an EGU (because they supply less than 1/3 of their potential electric output capacity and less than 25 MW net-electrical output to any utility power distribution system for sale). *Id*. at 33,431-32.

All fossil fuel-fired plants meeting the definition of an EGU, and providing baseload and intermediate load demand (including simple-cycle combustion turbines), should be included in new subpart TTTT and subject to the performance standards. First, a categorical exemption for simple-cycle combustion turbines simply is not justified on the bases EPA suggests. EPA has not shown that CO_2 emissions from these sources are in any way "*de minimis*." Indeed, EPA recognizes that such simple-cycle turbines are quite capable of producing electric output beyond just meeting "peak" loads and can operate in "intermediate" load as well as in "base-load following" modes. 77 Fed. Reg. at 22,432. In those uses, they emit significant (certainly not *de minimis)* amounts of CO_2.

Second, EPA has before it sufficient information to establish in the final rule a threshold for applicability for these sources, based on their use in "intermediate" or "baseload following" modes. Based on analysis of EPA's own Clean Air Markets Division data on simple-cycle combustion turbines, although currently almost all simple-cycle combustion turbines units have low annual operating hours, there are a dozen or so large units with high capacity factors. As discussed above, excluding all simple-cycle turbines from the requirement to meet the NSPS would provide incentives to develop more such sources. EPA's proposed use of the definition of electric generating unit to address this issue leaves open the possibility of uncontrolled units (particularly load-following units) operating at less than rated capacity for long periods of time (*e.g.*, 60 percent capacity for 50 percent of the year). Figure II-1 below (analysis of EPA's Clean

Air Markets Data) further shows that a threshold of approximately 2000 annual operating hours of operation for the year 2011 (the most favorable[3] year for industry) is more reasonably used as a proxy for intermediate or baseload use than the 2900 hours threshold EPA suggests. Based on this data, we strongly urge EPA to adopt the lower 2000 annual operating hours threshold for including simple cycle units as affected facilities in the final rule.

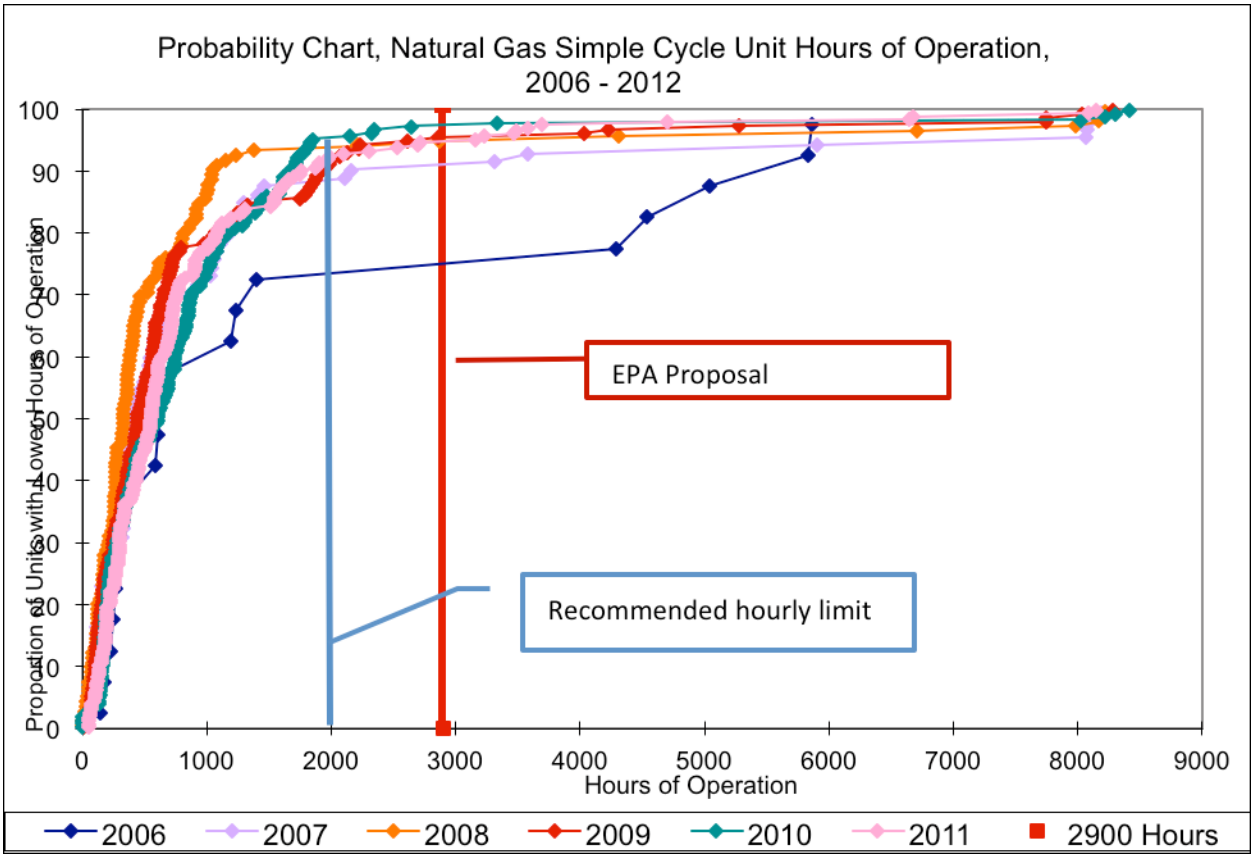

Figure II-1. Hours of Operation for Combustion Turbines, by Year
Source: (Dr. Phyllis Fox, analysis of EPA Clean Air Markets Data).

[3] Notably, the 2011 figures show sizable amount of growth in such use of these facilities, as for 2008 the comparable figure was 1100 hours.

III. The Level of the Proposed Standard, Including the 30-Year Averaging Period Is Amply Justified On the Record Before the Agency, and Bolstered By More Recent Information; But the Final Standard Should Be Framed in Net Output Terms.

EPA proposes a CO_2 performance standard set at 1000 pounds per MWh (gross), on a 12 month operating annual average basis, and with a 30-year compliance pathway for those sources that choose to delay meeting the standard by utilizing carbon capture and sequestration systems (CCS). 77 Fed. Reg. at 22,392. EPA seeks comment on all aspects of this proposal, including

- whether the gross energy output metric EPA has proposed is correct, or whether the standard should be set on a net output basis;
- whether establishing a 30-year averaging provision for those facilities utilizing CCS, including interim annual standards of 1800 pounds per megawatt hour (gross) in years 1-10, and 600 pounds per megawatt hour (gross) in years 11-30, is justified or should be varied;
- whether the existence of state standards requiring 1100 pounds CO_2 per MWh emissions limits should affect the level of the national standards EPA proposes; and
- whether the CO_2 emissions rate should be finalized at the level EPA has proposed, or instead at a lower or higher level, within a range of emissions rates between 950-1100 pounds CO_2 per MWh (gross).

A. EPA's EGU Performance Standards for CO_2 Should be set on a Net Output Basis.

EPA proposes to establish these CO_2 performance standards for subpart TTTT in "gross output" terms – that is, measuring the allowable CO_2 emissions rate based on the total amount of electricity produced, whether or not that electricity is used on site to run controls or other systems. 77 Fed. Reg. at 22,439/3-22,440/1. At the same time, however, EPA states its understanding that when establishing a performance standard for EGUs, "the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer." 77 Fed. Reg. at 22,431/3. We agree with EPA on this point, and urge the agency to establish the standards on a net output basis, that is, to express the allowable CO_2 emissions rate per unit of "useful" electrical output.

Setting the new source emissions standard on a net output basis promotes more efficiency throughout the design of a new EGU. Moreover, the incremental costs of measuring net electric output of a plant are minimal and not a valid basis for finalizing the standards on a gross output basis.[4] Moreover, a net output based standard for new sources will encourage the selection of more efficient electric generating unit designs, whether natural gas or coal, will promote selection of fuels that require less emissions control equipment in the first instance, and will reward selection of more energy-efficient electrical equipment to be used onsite at the new EGU (such as electric pumps, motors and fans). In addition, and very importantly, a net output based standard provides incentives over the longer run for research and development of more energy efficient control equipment (for example, but not limited to, the components of future CCS technology systems).

As EPA correctly notes, net electric output from an EGU is the power made available for sale to the grid (and in the case of a CHP unit that sells power to the grid, certain heat produced for sale may be counted as an energy output of the facility). For NGCC power plants, DOE estimates that internal electricity usage (sometimes called "parasitic loads") reduce net facility output to roughly 98 percent of gross output, while for supercritical coal power plants parasitic loads reduce net output to roughly 95 percent of gross output, and for coal IGCC power plants, parasitic loads reduce net output to about 83 percent of gross output.[5] In all of these cases, however, the important figure is not the parasitic loads themselves but the ultimate amount of electricity that can be usefully sold per unit of fuel used. This is measured by the *net* efficiency (and is more than 50 percent for the NGCC case in DOE's analysis, and roughly 39 percent for the supercritical pulverized coal and coal IGCC cases).[6]

Application of CCS technology to coal power plants increases parasitic loads (*e.g.*, electricity for CO_2 compressors) and other internal energy demands (*e.g.*, steam used in CO_2 separation processes). These internal energy demands for CCS can be modest, however,

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[4] First Energy Corp., *Measurement of Net Versus Gross Power Generation for the Allocation of NOx Emission Allowance*, at 3 (Jan.27, 1999) *available at:* http://www.epa.gov/airmarkt/progsregs/nox/docs/netvgrow.pdf). Attached as Exh. III-1.

[5] US Department of Energy (DOE), National Energy Technology Laboratory (NETL), *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2*, at ES-2 (November, 2010) available at http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_Rev2.pdf) (Attached as Exh. III-2).

[6] *Id.*

especially at the modest capture levels contemplated in EPA's proposed rule making. In fact, a recent DOE analysis indicates that a new coal IGCC power plant with enough CCS to reduce emissions to near 1010 pounds CO_2 per MWh (net) would have an overall efficiency of more than 36 percent, as compared to an overall efficiency of 39 percent without CCS, implying a decrease in efficiency attributable to CCS of less than 3 percentage points.[7] For a supercritical pulverized coal power plant, utilizing CCS to attain close to 1000 pounds of CO_2 per MWh (net) would entail a slightly more significant efficiency penalty (reducing overall efficiency from a little over 39 percent to about 33 percent in DOE's analysis).[8] Overall, setting net output based emissions standards for CO_2 from this industry will encourage more efficient systems and control technologies.

B. EPA's 30-Year Compliance Option is Legally Justified-EPA can and should include mechanisms to promote emerging technologies.

EPA proposes that new coal- or petroleum coke-fired EGUs using CCS technology systems to achieve the proposed 1000 pounds CO_2 per MWh (gross) performance standard emissions levels may do so over a 30-year averaging period, including enforceable annual maximum emissions rates in years 0-10 and 11-30. 77 Fed. Reg. at 22,417-18, 22,436/3 (proposed 40 C.F.R. §60.5520(b)); 22,438/2 (proposed 40 C.F.R. §60.5540 (c)). Specifically, such facilities must achieve a standard of 1800 pounds CO_2 per MWh (gross) on a 12-month operating annual average basis during years 1-10, and thereafter must achieve a standard of 600 pounds CO_2 per MWh (gross) on a 12-month operating annual average basis, such that the average does not exceed the 1000 pounds CO_2 per MWh (gross) limit on a 30-year average basis. 77 Fed. Reg. at 22,436/3 (proposed 40 C.F.R. §60.5520(b)).

EPA describes the 30-year averaging period as an "alternative compliance option" for plants relying on a CCS system to meet the proposed performance standard, and seeks comment on the legal justification for it, and on whether the details of the proposal provide adequate support and flexibility to those seeking to use CCS technology to achieve the standards. EPA's proposal is legally justified, and even demanded, by the statutory objective that section 111 rules should support and encourage widespread use of emerging technologies with significant

[7] DOE, NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture,* at ES-15 (May 27, 2011) (DOE/NETl-2011/1498). Attached as Exh. III-3.
[8] *Id.* at ES-14.

potential to provide deep reductions in air pollution emissions. As noted above in section I, the statute, its history, and court rulings all direct the Agency to be forward looking and technology-forcing in setting new source standards for a listed industry. *Sierra Club v. Costle*, 657 F.2d at 347 & n. 147 (asserting that NSPS must induce, stimulate, augment the search for more effective, less costly systems of air pollution control, and citing legislative history); *ASARCO*, 578 F.2d at 322 (NSPS must be designed based on the *best* system of emissions reduction); *Portland Cement*, 486 F.2d at 391 (in setting a NSPS, EPA "may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness" and cannot be conjured out of thin air). Moreover, EPA is authorized to create a regulatory structure or provisions that encourage the development of promising emerging technologies. *Sierra v. Costle,* 657 F.2d at 346-47.

EPA's 30-year compliance period is necessary for precisely these reasons – the agency recognizes that CCS is available and can achieve the proposed standard immediately on some new coal-fired EGUs, 77 Fed. Reg. at 22,418, but that the 30-year averaging period may be needed by others, and will permit the "continued scaling of CCS, a process that can be expected to lower the costs of CCS in the future." *Id.* While EPA thus discusses the benefits of the 30-year compliance option in terms of promoting lowered costs, it is notable as well that this technology provides the only currently available process with the potential to achieve near zero carbon emissions while enabling continued energy production from fossil fuels. Widespread, early adoption of CCS is critical – not only on coal EGUs, but eventually on all fossil fuel-fired EGUs, if the U.S. is ever to meet its goal of 83 percent reductions from 2005 greenhouse gas emissions levels. For that reason, EPA's provision of an alternative compliance period for any EGU proposing to use CCS to meet the performance standard, is a legally justified provision to enable and promote this promising technology.

In fact, the 30-year averaging period, including a full ten-year period during which uncontrolled CO_2 emissions at the 1800 pounds CO_2 per MWh (gross) level characteristic of today's supercritical coal plant emissions rates are permitted, is quite generous. New plants utilizing CCS systems today, or proposing to do so, already can achieve earlier, deeper reductions. *See infra* 40-41 (describing levels of emissions reductions for coal plants proposing to use CCS to control CO_2 emissions). Any alternative compliance framework for coal plants

proposing to use CCS should be informed by the performance and objectives of the developers who are working with this technology. *Cf.* Comments of Tenaska, Inc., Docket No. EPA-HQ-OAR-2011-0660-9359, at 2 (June 18, 2012) (suggesting that such a facility "be allowed to emit any combination of average annual emission rates so long as the 30-year average does not exceed 1,000 lbs/MWh…."). Any alternative formulation of the limit must, however, require enforceable interim annual emissions limits, to be included in the PSD and Title V permits for such a facility. *See* 77 Fed. Reg. 22,406/3. That would allow flexibility sufficient to promote and advance this promising emerging technology, while at the same time ensuring that the performance standards are enforceable on an annual basis. For this reason, EPA's selection of a 30-year averaging period, accompanied by enforceable annual emissions rates allowing a 10-year phase in of CCS systems is a more than reasonable exercise of EPA's authority.

EPA also offers as a policy rationale the idea that "[b]ecause CO_2 is long-lived in the atmosphere, the 30-year averaging period, as structured, with shorter term compliance requirements, is not expected to have a different impact on climate compared to meeting the standard of performance." 77 Fed. Reg. at 22,418/2. While we agree that the 30-year averaging period is a reasonable exercise of EPA's discretion to design a standard to promote and advance promising emerging technologies, we do not agree that EPA's "long-lived nature of CO_2" policy rationale supports a 30-year compliance option. In fact, just the opposite is true: because a large fraction of every ton of CO_2 emitted to the atmosphere persists (causing climate damage) for many decades to a century, near-term reductions are critical. And, every additional ton permitted by the near-term relaxation of EPA's 1000 pounds CO_2 per MWh standard to accommodate CCS technology in the early years of system operation will prolong the problem beyond what will occur if operators are required to meet the standard immediately. The question really is whether that environmental cost is "worth it," in order to advance and promote the widespread use and development of a technology without which continued use of fossil fuels (gas and coal) is not sustainable. We believe the answer is yes. But that is the basis for justification of the 30-year period, not the "long-lived nature of CO_2."

C. Existing State CO_2 Emissions Requirements Provide Additional Support for The Level of EPA's Proposed Standard – and Further Indication of the Need for Nationwide CO_2 Emissions Limits.

EPA notes the existence of state programs that set emission standards at levels at or near 1,100 lbs CO_2 per MWh, in the context of requesting comment on a range of emissions limits ranging from 950 pounds CO_2/MWh to 1,100 pounds/MWh. *See* 77 Fed. Reg. at 22,414/2 (discussing California, Washington, and Oregon statewide GHG emissions limits for new – and in the case of California and Oregon, existing – baseload EGUs). In essence, EPA asks whether the existence of these standards affects EPA's selection of a final proposed performance standard for new subpart TTTT. Of course, there is no legal requirement for EPA to *follow* State standards. Indeed, the opposite is true; CAA section 116 requires States at least to meet EPA national section 111 standards. 42 U.S.C. §7416.

The Act's history – and the history of section 111 in particular – illustrates that Congress had in mind that

> The promulgation of Federal emission standards for new sources…will preclude efforts on the part of States to compete with each other in trying to attract new plants and facilities without assuring adequate control of extra-hazardous or large-scale emissions therefrom.

H.R.Rep. 91-1146, 91st Cong. 2d Sess. 3, reprinted in Legislative History 893 (1970). This concern about a "rush to the bottom" does not speak directly to the question of whether State first-mover programs must be considered by EPA in setting national standards. As courts have noted, however, this concern was not the *only* purpose behind the adoption of section 111. *See, e.g. U.S. v. City of Painesville*, 644 F.2d 1186, 1192-93 (6th Cir. 1982)(citing H.R.Rep. 91-1146, 91st Cong. 2d Sess., at 3 and S.Rep. No. 91-1196, L.H. at 416 (1970), for the proposition that the "overriding purpose of section 111 is to prevent significant new pollution problems," in particular from electrical generating plants, which Congress intended "must be controlled to the maximum possible degree").

In the current rulemaking, as set out further below in detail, the record before the Agency amply demonstrates that the proposed standard can be met or exceeded by not just one but two "best system of emissions reduction" options – NGCC plants and CCS systems. For that reason, the existence of State programs requiring less stringent emissions standards, while offering support for the idea that performance standards at the high end of EPA's proposed range are reasonable and achievable, do not demand the adoption of EGU standards set at the weaker emissions limit of 1100 pounds CO_2 per MWh. That is particularly true because the State

standards are already in place, and in one case has been in place for 5 years – they represent, if anything a backward looking view of the appropriate emissions limit, not a "look[] toward what may fairly be projected for the regulated future." *See Portland Cement I*, 486 F.2d at 391.

D. Current Federal Underground Injection Control Regulations and Clean Air Act Monitoring and Reporting Requirements Provide A Framework for Ensuring that Sequestration Systems Support the Proposed Standard, and will Not Damage Underground Sources of Drinking Water.

A national regulatory framework now exists to support a determination that CCS is the best system of emissions reduction for any industry using that technology, and that CCS will be deployed in an environmentally protective manner. In 2010, EPA established a well class specifically designed for the geologic sequestration of CO_2 under the Federal Underground Injection Control program (UIC). *Federal Requirements Under the Undergound Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells*, 75 Fed. Reg. 77,230 (December 10, 2010). These wells, deemed "Class VI" wells, are designed to ensure that injected CO_2 remains in a specified area and that CO_2 is properly monitored. EPA has also 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.[9]

CO_2 sequestration may also concurrently occur in enhanced oil recovery (EOR) operations. UIC Class II injection permits are required for injections of CO_2 for EOR, and a process is available to obtain Class VI permit coverage for full-scale sequestration after oil production operations cease. *See* 40 C.F.R. §144.19 (2012).

Furthermore, under the U.S. Tax Code, 26 U.S.C. §45Q(d)(2), tax credits are available for those owners or operators who successfully sequester CO_2 from atmospheric release. Therefore, facilities that utilize CCS must do so within a regulatory framework that ensures the CO_2 is properly accounted for, and has been isolated from atmospheric release, as well as that sequestration is occurring in a way protective of underground sources of drinking water.

[9] *See* EPA, Geologic Sequestration Guidance Documents (available at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm) (collection of links to EPA guidance documents for the Class VI well program) (last viewed June 25, 2012).

Where operators opt to conduct geologic sequestration of CO_2, as a part of or after conclusion of EOR operations, monitoring and reporting occurs pursuant to EPA's Greenhouse Gas Reporting rule under Subpart RR, 40 C.F.R. §98.440 *et seq.* (2012) (Geologic Sequestration of Carbon Dioxide). 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. The SDWA UIC Class VI and CAA Subpart RR rules, taken together, provide protection of underground sources of drinking water (USDW) and an accounting mechanism for measuring and crediting a source with the amount of CO_2 that is sequestered from atmospheric release. However, subpart UU under the GHG reporting Rule (UU, 40 C.F.R. §98.470 *et seq.* (2012)(Injection of Carbon Dioxide)), which only required reporting of new (purchased, not recycled) volumes of CO_2, is inadequate for purposes of crediting sources of captured CO_2. Because of the advantages of using currently available EOR for sequestration, which are described *infra*, as experience is gained with geologic storage in EOR, EPA should evaluate the effectiveness of current requirement for EOR operators operating under UIC Class II, and determine whether existing protections can be made more effective and whether new protections are warranted. For example, EPA should review the following areas of the current UIC Class II requirements for EOR:

- Area of review: are the area of review requirements appropriate to an EOR field, are requirements for geologic and geophysical site characterization adequate to a determination of the ability of a particular site to contain CO_2;
- Do the current requirements adequately require identification of and remedying of all inadequately plugged and abandoned wells;
- Do the current rules adequately require well construction methods and materials;
- Are the methods required for use in monitoring injected CO_2 and subsurface CO_2 plumes sufficient;
- Are the requirements for the mitigation of leakage sufficient; and
- Are existing well closure requirements and any subsequent monitoring sufficient to ensure sequestration?

E. The Level of EPA's Proposed Standard is Justified *on the Record Before the Agency*, Not Only Based on New NGCC Plants, but also because CCS is a Best System of Emissions Reduction for this Industry.

The current record before the Agency amply justifies a 1000 pounds CO_2 per MWh standard, whether defined in gross energy output terms, or as a net output-based standard. Indeed, the supporting record amply justifies a lower standard, even below the 950 pounds per MWh (gross) low-end range on which EPA seeks comment. In order to encourage adoption of the most efficient currently available systems for control, and to promote and create incentives for newer, more efficient systems over the regulated period, EPA must set the final standard on a net output basis.

The standard is justified not only (as EPA has suggested) on the basis that a natural gas combined cycle plant (NGCC) is the BSER for the new subpart TTTT category, but also because CCS control technology systems are available as BSER for the limited amount of coal plant development EPA projects during the regulated period between 2012 and 2020. EPA's own record demonstrates that the agency can go further than simply describing CCS as an "alternative compliance pathway." Specifically, EPA's record shows that CCS systems are "available" and in use now on coal- and natural-gas fired power plants in the U.S., as well as in industrial uses here and abroad in contexts that support technology transfer. *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). The absence of a regulatory driver, and the limited availability of financial incentives for the industry has meant that to date, CCS utilization has been somewhat limited. But its importance must be considered in the context of the enormous potential for future emissions reductions associated with CCS systems – these systems are the only currently available technology that can permit the use of coal and gas for the production of electricity, at near zero emissions levels.

As discussed in Section I, above, EPA is not limited to establishing new source emissions limits based on systems of emissions reduction that are in "widespread use" in the industry. To the contrary, courts have repeatedly noted, following the court's 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 National Asphalt Pavement Ass'n*, 539 F.2d at 786 (same); *National Lime Ass'n*, 627 F.2d at 431 (achievability is determined "for the industry as a whole"). Because CCS

is successfully being used today both on EGUs and in several analogous industrial settings, to completely isolate CO_2 from atmospheric release, CCS is a BSER for fossil fuel fired EGUs. CCS is BSER on EPA's own record, because as shown below, information in the record shows that applying CCS enhances rather than simply maintains emissions reductions during the regulatory period.

Nor is EPA limited to the selection of a single control option as the BSER supporting a performance standard applicable to an industrial source category. EPA has authorized the use of several different systems as BSER for specific source categories. In *National Lime Ass'n.*, 627 F.2d at 326, EPA identified several different "best systems" of emission control for rotary lime kilns: baghouses, ESPs and scrubbers were all considered "best systems" for this source category. Similarly, in *Sierra Club v. Costle*, 657 F.2d at 326, EPA announced five different kinds of wet scrubbers that were available as BSER to help support a nonuniform standard, and also found that a nonuniform standard was appropriate to promote the use of dry scrubbers. The Court in *Sierra Club* explained that the rulemaking there focused "not on which technology should be employed, but on the appropriate level of control." *Id*. EPA's designation in the proposal of NGCC as BSER therefore does not preclude CCS from also being BSER (for both coal and gas plants). Moreover, in setting new source standards for a regulated industry, EPA "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." *Portland Cement I*, 486 F.2d at 391. And, as EPA acknowledges, the current record before the agency demonstrates that CCS is "technologically feasible for implementation at new coal-fired power plants, and its core components (CO_2 capture, compressions, transportation and storage) have already been implemented at commercial scale." 77 Fed. Reg. at 22,414/3. On its own record EPA reaches four conclusions:

1. CCS is technologically achievable for implementation at new coal-fired power plants and its core components (CO_2 capture, compression, transportation and storage) are commercially available.[10]

[10] 77 Fed. Reg. at 22,415-16, 22,418, & n.56. (*citing* DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, U.S. Department of Energy National Energy Technology Laboratory (December 2010)) (attached as Exh. III-4); *see also Summary of Interagency Working Group Comments on Draft Language*, Docket Id. No. EPA-HQ-OAR-2011-0660-0030 at 1.

2. There is reason to expect that the costs of CCS will decrease over time, and in any event, economic subsidies for CCS, as for other energy systems and new control technologies are not an unusual condition.[11]

3. We expect construction of no more than a few new coal-fired power plants by 2020 and that CCS is "feasible and sufficiently available for the expected number of coal plants, based on a 30-year averaging compliance path."[12]

4. Several states already have set emission standards that make implementation of CCS necessary for the development of new coal-fired power plants.[13]

While EPA couches its discussion in terms of support for CCS as an "alternative compliance pathway" for coal plants, the record in fact directly supports the level of the standard EPA has proposed on the basis of the application of CCS as the BSER for the industry. The record for this rulemaking identifies the following coal-fired power plant CCS projects that are, will, or have been in commercial operation:[14]

- AES's coal-fired Warrior Run (Cumberland, MD) (operating)
- Shady Point (Panama, OK) (operating)
- Searles Valley (Trona, CA) (operating)
- American Electric Power Co. Mountaineer Plant (pilot complete)
- We Energies Pleasant Prairie (pilot complete)

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[11] 77 Fed. Reg. at 22,418/3, nn. 57-58 (*citing* John M. Dutton and Annie Thomas, "Treating progress Functions as a Managerial Opportunity," 2, 235-247; Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investing Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," Organizational Science, Vol. 2, No. 1, February 1991; International Energy Agency, Experience Curves for Energy Technology Policy, 2000; and Paul L. Joskow and Nancy L. Rose, "The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units," RAND Journal of Economics, Vol. 16, Issue 1, 1-27, 1985. See discussion in "The Benefits and Costs of the Clean Air Act from 1990 to 2020," U.S. EPA, Office of Air and Radiation, April 2011; Ruben, E.S.; Yeh, S.; Antes, M.; Berkenpas, M.; Davison J.; "Use of experience curves to estimate the further cost of power plants with CO2 capture," 1 Intl. J. of Greenhouse Gas Control,188 (2007)).

[12] 77 Fed. Reg. at 22, 414/1 (Noting that EPA used the Integrated Planning Model (IPM), Docket ID No. EPA-HQ-OAR-0660-0060, for projected new coal plant construction, keyed to the Annual Energy Outlook (AEO) and showing a pattern of little future construction of new coal-fired plants); *see also id.* n.46 (citing http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation); *id.* at 22,418 -22,419 (noting that EPA identifies CCS as a compliance option based in part on the expectation that it will cost less in the future).

[13] 77 Fed. Reg. at 22,414/2 (*citing* California Senate Bill 1368 (2006), Washington Senate Bill 6001 (2007), and Oregon Senate Bill 101 (2009)) (Attached as Exh. III-5).

[14] 77 Fed. Reg. at 22,416/3-17/2.

- Vattenfall (Schwarze Pumpe, Germany) (operating)
- Southern Company's Alabama Power Plant Barry (operating
- Mississippi Power Plant Ratcliffe (under construction)
- The Texas Clean Energy Project (Odessa, TX) equipment ordered).

In *Lignite Energy Council,* 198 F.3d at 934, the court explained that a control on one industry may serve as BSER for performance standards on another similar industry. The Court explained that it was appropriate for EPA to "compensate for the shortage of data" by "reasonable extrapolation of a technologies performance in other industries" where "data was unavailable," although EPA could not base its decision on "mere speculation or conjecture." *Id. (citing National Asphalt Pavement Ass'n, v. Train,* 539 F.2d 775, 787 (D.C. Cir. 1976); *Weyerhaueuser Co. v. Costle,* 590 F.2d 1101, 1054 n.70 (D.C. Cir. 1978)). In addition to the CCS demonstrations on electric generating units, EPA's record notes up to 2 million tons of CO_2 per year for the last 12 years has been and continues to be captured from a coal gasification facility in Beulah, North Dakota, compressed, and piped to Saskatchewan where it is sequestered in EOR fields. While the Dakota gasification facility is not used to generate electricity, it uses gasification, capture, and compression technologies, and applies pipeline transportation and oilfield sequestration of CO_2 in the same way as will Plant Ratcliffe and Summit Energy's Texas Clean Energy Project.

International experience with CCS technology also supports it as a "best system of emissions reduction" for the EGU industry. *See Lignite Energy Council,* 198 F.3d at 934 n. 3 (discussing transfer from international applications as acceptable basis for NSPS). EPA notes that four large CCS projects (Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada) represent 25 years of experience in capturing and permanently storing CO_2 underground.[15]

EPA furthermore relies extensively on the Interagency Task Force on Carbon Capture and Storage, (co-chaired by the DOE and the EPA), which found that "although early CCS projects face 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

[15] 77 Fed. Reg. at 22,415/2 & nn. 50, 51 (*citing* Dooley, J. J., *et a*l., *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*. U.S. Department of Energy, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830 (2009))(attached here as Exh.III-6).

insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions." 77 Fed. Reg. at 22,414-15 (*citing Report of the Interagency Task Force on Carbon Capture and Storage* (August 2010)) (attached here as Exh.III-7).

EPA notes that three options exist to capture CO_2 from power plant emissions: 1) Pre-combustion systems, 2) Post-combustion systems, and 3) Oxy-combustion. "Each of these three carbon capture approaches…is technologically feasible. However, each results in increased capital and operating costs and decreased electricity output…." 77 Fed. Reg. at 22,415/1. The agency notes that the need for subsidies to support emerging energy systems and new control technologies is decidedly not an unusual condition:

> 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—for some aspect of development and utilization, ranging from exploration to control installation. This is true for fossil fuel-fired; as well as nuclear-, geothermal, wind-, and solar-generated electricity."

Id. at 22,418/3.

Moreover, EPA is within its discretion to base the 1000 pounds CO_2 per MWh (net) emissions standard on CCS technologies because CCS costs will fall as the technology is more commonly used, and performance improves during the regulated future. *Sierra Club v. Costle*, 657 F.2d at 347 & n. 147 (asserting that NSPS must induce, stimulate, and augment the search for more effective, less costly systems of air pollution control, and citing legislative history of the 1977 Amendments). To evaluate the costs of the standard, EPA must consider the economic cost associated with achieving the reductions as well as the cost to the environment if the reductions are not achieved. *See Essex Chemical*, 486 F.2d at 433 (explaining that a system is adequately demonstrated when it has been shown to be "reasonably reliable, reasonably efficient and...can reasonably be expected to serve the interest of pollution control without becoming exorbitantly costly in an economic or environmental way"). Therefore, when evaluating the costs of the standard, EPA cannot neglect to consider the social cost of carbon on the environment. *See Portland Cement I*, 486 F.2d at 385.

In the Regulatory Impact Analysis, EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units*, at 5-28, Docket ID No. EPA-HQ-OAR-2011-0660-0024 (March 2012) (hereinafter "RIA"), EPA used the social cost of carbon to compare the damages of building a new coal-fired power plant without CCS relative to a NGCC plant –also without CCS – in 2020, despite the fact that no new coal plants are projected to be built in that timeframe. The monetized damages, presented in dollars per MWh, were intended to include (but were not limited to) the damages to net agricultural productivity, human health, property (from increased flood risk), and ecosystem services. *Id.*

The results, though conservative, show that continuing to emit CO_2 at uncontrolled, high rates will have significant costs to the public. Specifically, EPA's social cost of carbon analysis determined that – depending on the "discount rate"– a new coal-fired power plant would result in damages ranging from $3 to $34 per MWh more than a NGCC plant. *Id.* at 5-30, Table 5-7. In other words, higher CO_2 emissions result in a significantly higher environmental cost, and EPA must consider such costs when evaluating the standard– including when evaluating the costs of CCS.

Although EPA concludes that a requirement to achieve 100 percent CO_2 capture increases electricity costs by 80 percent for a new pulverized coal plant and by 35 percent for a new IGCC plant, the Agency has not proposed a standard requiring 100 percent CO_2 capture here. Instead, the proposed 1000 pounds CO_2 per MWh standard reflects approximately 30 percent capture (gross output basis) or 45 percent capture (net output basis). As noted above, EPA also recognizes that subsidies are now available and that U.S. DOE's research efforts aim to cut these cost increases to 30 percent and 10 percent respectively.[16] EPA recognizes that once 100 gigaWatts of CCS capacity is built, it is likely that technology costs for NGCC-CCS would fall by 40 percent, the costs of coal post-combustion capture will fall by 26 percent, and the costs

[16] 77 Fed. Reg. at 2,415/3 – Page 22416/1 n.56, *citing* DOE/NETL. *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, (December 2010), attached here as Exh. III-4).

of IGCC (the precombustion capture technology evaluated) will fall by 13 percent.[17] *Id.* at 22,416/2.[18]

In the RIA for the proposal, issued in March 2012, EPA examines CCS costs for partial capture and offsetting EOR revenue. In a sensitivity analysis, EPA concludes that in the unlikely event that coal plants rather than natural gas plants are built between 2012 and 2020, the "level of avoided negative health and environmental effects expected would imply net social benefits from this proposed rule."[19] We agree, and further note that these health and environmental benefits, through the significantly larger CO_2 emissions reduction available from this industrial sector due to the deployment of CCS technologies, *must* be achieved if the U.S. is to control fossil CO_2 emissions sufficiently to meet its 2050 climate goals. As shown *supra*, the need for and promise of an integrated physical system supporting this control technology is not only with respect to control of coal-fired power plants, but must also be available for controlling CO_2 emissions from natural gas plants in the coming decades, if the U.S. is to take the steps needed to avoid the worst impacts of climate change. Such considerations are well within EPA's authority to evaluate (and rely on) when selecting the level and form of new source performance standards for this industry. *Sierra Club v. Costle*, 657 F.2d at 374.

The results of EPA's cost analysis are summarized in the Table 5-8, taken from EPA's Regulatory Impacts Analysis, and reproduced below:[20]

[17] 77 Fed. Reg. at 22,416/2 n.58, *citing* Rubin, *et al. Use of experience curves to estimate the future cost of power plants with CO2 capture*, Intl. J. of Greenhouse Gas Control, 1, 188 (2007). (attached here as Exh. III- 8),

[18] 77 Fed. Reg. at 22,415/3 – 22,416/1 n.56, (*citing* DOE/NETL, *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, (December 2010).) (attached here as Exh. III-4).

[19] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, Page ES-3, Docket ID No. EPA-HQ-OAR-2011-0660-0032 (March 2012).

[20] *Id*. at 5-36.

Table 5-8. Illustrative Costs and Benefits for two CCS Scenarios Compared to Conventional Coal Plant (per MWh 2007$)

	SPC to IGCC with 39% Capture	SPC to IGCC with 90% Capture
Additional Gross Annual Private Costs	$17	$34
Revenue from EOR	$5 (@$15/ton)	$37(@$45/ton)
Net Additional Annual Private Costs	$12	($3)
Value of Monetized Benefits		
SCC 3% with Pope 7%	$13	$24
SCC 3% with Laden 3%	$23	$34
Net Monetized Benefits		
SCC 3% with Pope 7%	$1	$27
SCC 3% with Laden 3%	$11	$37

EPA's current justification for the proposed standard is based on its modeling showing that because gas prices are expected to remain low through the regulatory period (2012-2020), few if any new coal plants will be built. 77 Fed. Reg. at 22,413-14. Specifically, EPA's IPM model shows few if any new coal builds up to 2020 and that what few projects are built will be CO_2-controlled using CCS supported by incentives.[21] But that finding actually supports relying on both NGCC and CCS as BSER for subpart TTTT CO_2 standards. EPA concluded "that the price of natural gas would have to increase to approximately $10/mmBtu for coal boilers without CCS to become competitive with combined cycle natural gas units, which is projected to be very unlikely."[22] EPA is correct that *even without the rule EPA has proposed*, developers today favor new gas plant construction because natural gas prices are at an all time low and natural gas plants have lower capital and operating costs than coal plants. And, while natural gas prices appear likely to remain low due to the current boom in unconventional gas development, historical data suggest that may not always be the case (*see* Figure III-1). EPA's proposed 1000 pounds CO_2 per MWh standard provides an important hedge against future energy sector CO_2 emissions increases which would occur (absent the standard) when natural gas prices increase. And CCS

[21] 77 Fed. Reg. at 22,416/2.

[22] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, page 5-1, Docket ID No. EPA-HQ-OAR-2011-0660-0032 (March 2012).

provides additional BSER support for the limit, as it promises significant emission reductions regardless of gas market fluctuations.

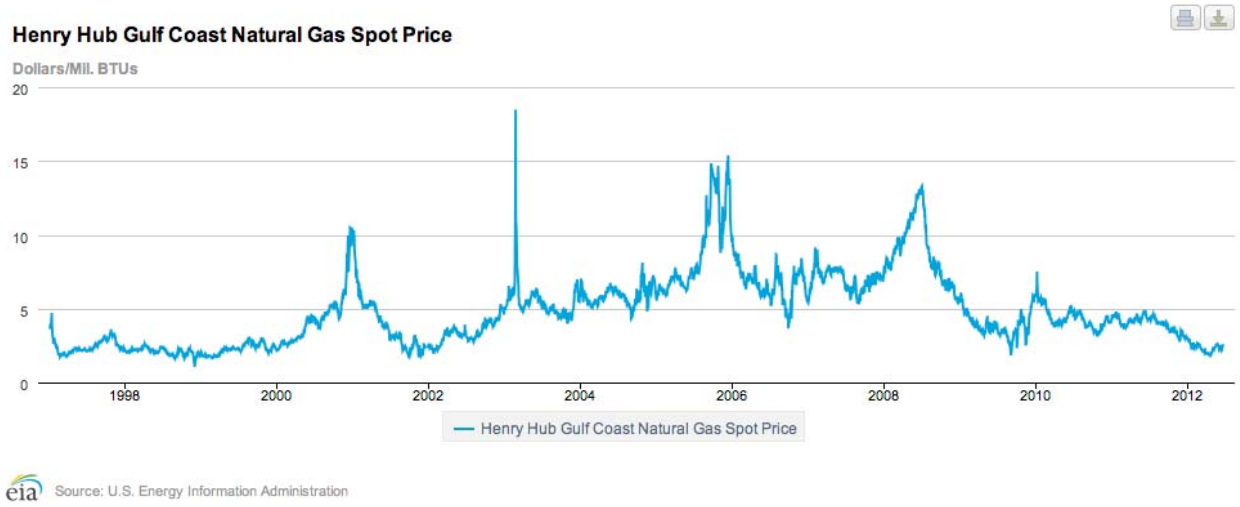

Figure III –1 (source: DOE, Energy Information Agency) (EIA data available at http://www.eia.gov/dnav/ng/hist/rngwhhda.htm).

The record before the Agency also documents the 40-year experience with CO_2 pipelines in the United States, which now total upwards of 3,600 miles and transport 50 million metric tons of CO_2 per year,[23] and that a study concluded that 95 percent of the 500 largest CO_2 sources in the US are within 50 miles of a potential permanent storage site.[24]

The record before the Agency documents the availability of ample geologic formations in the U.S., as it includes estimates that place total U.S. CO_2 storage potential at between 1,800

[23] 77 Fed. Reg. at 22,415/1 n.49, (*citing* Dooley, J. et al. *Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change.* Joint Global Change Research Institute, Battelle Pacific Northwest Division, PNWD–3602 (2006)) (Attached here as Exh. III –10).
[24] *Id.*

billion to 20,000 billion metric tons of CO_2.[25] By U.S. DOE's most conservative low estimate, this will be sufficient to serve as a CO_2 sequestration resource for 500 years.[26]

F. The Level of EPA's Proposed Standard also is justified on the basis of additional information not included in EPA's record to date demonstrating that CCS is BSER for fossil-fuel fired EGUs

EPA's record, while sufficient to support the establishment of a 1000 pound per MWh (net) standard based on CCS deployment over a 30-year time frame, does not include recent information about the rapidly developing status of this significant emerging control technology. We therefore offer the agency additional information underscoring that CCS is BSER supporting a CO_2 new source performance standard for new subpart TTTT. Specifically, we provide additional information showing that :

1. CCS is demonstrated and available for use at new coal- (and gas-) fired power plants and its core processes (CO_2 capture, transportation and sequestration) have already been utilized at large scale.

2. CCS adds acceptable costs to power plants, and continued development and expansion of CCS systems will reduce CO_2 capture costs to improve cost performance.

3. Ample U.S. geologic sequestration reservoirs are available to support significant emissions reductions from the fossil fuel fired EGU industry; and decades of experience with enhanced oil recovery operations and other sequestration around the globe support the choice of CCS as BSER in this performance standard setting.

Additionally, we offer a rebuttal below, in subsections 5. and 6. of this section, to two recent studies raising questions about conflicts between CCS and hydraulic fracturing activity for natural gas production, and seismic risk due to CCS saline injections.

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[25] 77 Fed. Reg. at 22,415/2 n. 52, (citing DOE, *The North American Carbon Storage Atlas*, Appendix C (2012) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf), attached here as Exh.III-71).

[26] *See* Press Release, "Energy Department Announces New Mapping Initiative to Advance North American Carbon Storage Efforts" (May 1, 2012) (Available at http://energy.gov/articles/energy-department-announces-new-mapping-initiative-advance-north-american-carbon-storage). Attached as Exh.III-82.

1. Up-to date information shows that CCS is demonstrated and available for use at new coal power plants and its core processes (CO_2 capture, transportation and sequestration) have already been utilized at large scale.

EPA identifies three forms of capture available for power plants: (1) Pre-combustion systems used in coal gasification plants that separate CO_2 prior to full combustion; (2) post-combustion systems that remove CO_2 from the flue gas produced after the fuel is combustion with air; (3) oxy-combustion systems that use high-purity oxygen instead of air to combust fuel resulting in a highly concentrated CO_2 flue gas. 77 Fed. Reg. at 22,415/1. New information, not relied on by the agency, shows that each of these kinds of capture systems is demonstrated at large scale, as shown below.

(a) Pre-combustion Systems are demonstrated and commercially available at large scale.

Pre-combustion capture of CO_2 is the process by which CO_2 is removed from the syngas of a gasification plant so that the remainder is mostly hydrogen. To accomplish the CO_2 removal, two steps are required in addition to the initial gasification: carbon in the syngas must be converted to CO_2 (in an operation called a 'water-gas shift reactor') and the CO_2 must be removed (in a device called an 'acid gas removal' or AGR system). By varying the amount of syngas 'shift' and AGR, the composition of the resulting syngas can be changed so that when it is burned it emits either a significant amount of CO_2 (with no 'shift' and no AGR), a modest amount of CO_2 (some shift, some AGR) or very little CO_2 (deep 'shift', deep AGR, resulting in a fuel composed primarily of hydrogen, which emits no CO_2 when burned).

A 2010 U.S. DOE database of gasification projects lists 125 individual coal gasifiers (and 2 petcoke gasifiers) at 19 commercial projects which are used to produce either ammonia, substitute natural gas (SNG), or gaseous feedstock for liquid fuels production.[27] All three of those processes (ammonia production, SNG, and liquid fuels production) entail significant amounts of syngas 'shift' and AGR. For many of these projects the Rectisol® pre-combustion capture process of the German firms Linde or Lurgi is used (*e.g.*, Dakota Gasification in the

[27] CATF analysis of DOE data. The DOE data is available at http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html, attached here as Exh. III-9.

United States[28] and Sasol in South Africa[29]); for others, OUP's Selexol™ process has been used (*e.g.*, the Coffeyville Syngas Plant in Kansas[30]). The total thermal capacity of these projects exceeds 20,000 MW, and some have been operating for decades.[31] CO_2 captured at the Dakota Gasification project is transported by pipeline to Canada, where it is used for enhanced oil recovery (EOR) and sequestered (see more below). CO_2 from the Coffeyville project is currently vented, but reportedly agreements have been signed to transport the CO_2 to Oklahoma for EOR and sequestration.

Additionally, pre-combustion capture systems have decades of commercial availability. In their extensive commercial analysis for an IGCC project in California that was to have 90% CCS, Hydrogen Energy International (a joint venture of BP and Rio Tinto) reported to the California Public Utilities Commission that Rectisol® was a "commercially proven design" with over 50 units in operation worldwide on gasifiers. HEI concluded that "both Linde and Lurgi have successfully demonstrated designs that incorporate each aspect of the HECA design [coal/petcoke IGCC with 90% CCS] and demonstrated the ability to integrate these features into one-of-a-kind designs." HEI subsequently entered commercial negotiations with one of the Rectisol vendors.[32] Summit's TCEP coal IGCC project in Texas will also use Rectisol®, and it is the basis for the CO_2 emission limits in a May 7, 2012 Indiana Department of Environmental

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[28] *See* DOE, Office of Fossil Energy, *Practical Experience Gained During the First Twenty Years of Operation of the Great Plains Gasification Plant and Implications for Future Projects*, at 24 (2006) (Available at http://www.fossil.energy.gov/programs/powersystems/publications/Brochures/dg_knowledge_gained.pdf) Attached as Exh. III-11.

[29] *See* Koss, U., State Of The Art Gas Technologies For Zero Emission IGCCs, at 8 (2002) (Available at http://www.cooretec.de/lw_resource/datapool/Neuigkeiten/technologies_co2_separation.pdf). Attached as Exh. III -12.

[30] UOP, *UOP Selexol Technology for Acid Gas Removal*, at 23 (2009) (Available at http://www.uop.com/wp-content/uploads/2011/02/UOP-Selexol-Technology-for-Acid-Gas-Removal-tech-presentation.pdf). Attached as Exh. III -13.

[31] CATF analysis of DOE data. The DOE data is available at http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html, attached here as Exh.III-9.

[32] *See* HEI, L.L.C., *HECA Feasibility study*, Report #23 – AGR Licensor Evaluation, at 3-4 (February 7, 2010). Attached as Exh. III-14.

Management (IDEM) air quality permit for a proposed gasification plant in Rockport, Indiana that would manufacture substitute natural gas from coal.[33]

The Selexol™ process is offered by UOP, a Honeywell company.[34] When Southern Company's Mississippi Power Company subsidiary won approval from the Mississippi Public Service Commission to build the 522 MW Kemper County IGCC power plant with 65% CCS, its senior executives testified that decades of industrial gas capture experience with Selexol™ was an important factor for the Mississippi Public Service Commission to use in assessing risk. Thomas O. Anderson, Vice President, Generation Development for Mississippi Power, testified that:

> The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable.[35]

Also, Kimberly D. Flowers, Vice President and Senior Production Office of Mississippi Power Company, testified that "[t]he carbon capture process design proposed for this Project has been in commercial use in the chemical industry for decades. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated in the Plant's design is manageable."[36] CATF estimates that the CO_2 emissions from the Kemper County EGU facility will be approximately 786 pounds CO_2 per MWh (net), equivalent to 541 pounds CO_2 per MWh (gross), and well below the proposed performance standard.[37]

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[33] *See* Permit IDEM No. T147-30464-00060, Condition D.4.9 (Available at http://permits.air.idem.in.gov/30464p.pdf). Attached as Exh. III -15.

[34] UOP, *UOP Selexol Technology for Acid Gas Removal*, at 23 (2009) (Available at http://www.uop.com/wp-content/uploads/2011/02/UOP-Selexol-Technology-for-Acid-Gas-Removal-tech-presentation.pdf). Attached as Exh. III -13.

[35] Mississippi Power Company, MS Public Service Commission Docket 2009-UA-14, Phase Two Direct Testimony of Thomas O. Anderson, at 22 (December 7, 2009), attached here as Exh. III-16.

[36] Mississippi Power Company, MS Public Service Commission Docket 2009-UA-14, Direct Testimony of Kimberly D. Flowers, at 42 (January 16, 2009), attached here as Exh. III -17.

[37] According to Mississippi Power Company filings before the Mississippi Public Service Commission the net output of the Kemper IGCC facility (when not using natural gas-fired duct burners) will be 522 MW and there will be 237 MW of auxiliary loads, implying a gross output

In a power generation context, the gasification through syngas shift and AGR steps do not alone complete the pre-combustion CO_2 removal process. The resulting elevated-hydrogen syngas must also be burned in a combined cycle combustion turbine to produce electricity for sale. This change presents no unreasonable technical challenges to the turbine, however. By 2006 Siemens had already accumulated more than 750,000 hours of operation with elevated-hydrogen fuels in combustion turbines, [38] and GE had accumulated over 900,000 hours.[39] Another turbine and gasification vendor, MHI, also offers an IGCC with Selexol™ to achieve 60-65 percent CCS.[40] As a result, in their evaluation of high-hydrogen combustion turbines for the HECA IGCC project with 90 percent CCS, HEI determined that "commercial guarantees for F class turbines operating on high-hydrogen fuels would be likely."[41]

New gasification power plants are in the best position to integrate pre-combustion capture into designs. As recognized by Congress as long ago as 1970, new plant developers are in the best position to integrate significant new control technologies into plant designs. *See* S. Rep. 91-1196 at *17. In fact, for new IGCC, even with CCS, risks are manageable and/or absorbed through performance guarantees. Southern Company's Kemper IGCC with 65 percent CCS will use combustion turbines from Siemens with their elevated-hydrogen fuel, and the company told the Mississippi Public Service Commission that at the modest level of CO_2 capture expected at the facility, these turbines will be "dual-fuel capable" and will not require costly modifications from those used only with natural gas.[42] In a 2011 analysts briefing, Mississippi Power Company

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of 759 MW derived from coal. CO_2 emissions are expected to be 1.6 million short tons per year, at 89% capacity factor. This implies an average emission rate of 786 lb per MWh (net), equivalent to 541 lb per MWh (gross). *See* MPSC Docket No, 2009-UA-0014, MPCo response to Boston Pacific data request of December 15, 2009, items 3-35 and 3-50 and 3-53, attached as Exh. III-18.

[38] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009) (citing Brown, P., *Siemens Gas Turbine H2 Combustion for Low Carbon IGCC*, (Oct. 2007)). Attached as Exh. III -19.

[39] Shilling, N., Testimony of Norman Shillingon Behalf of Joint Petitioners in Cause No. 43144 Before the Indiana Utility Regulatory Commission (Oct. 24, 2006). Attached as Exh. III-20.

[40] Sakamoto, K., "Commercialization of IGCC/Gasification Technology for US Market", Oct. 7, 2008. Attached here as Exh. III -21.

[41] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009). Attached as Exh. III- 19.

[42] Mississippi Power Company, response to Data Request Item No. Entegra 4-9, Before the Mississippi Public Service Commission, Docket No. 2009-UA-0014 (January 27, 2010). *See* Exh. III-18.

President and CEO Ed Day and Executive Vice President, Engineering and Construction Penny Manuel concluded that the Kemper IGCC posed no construction risks that were materially different than other major construction projects including scrubber additions to existing power plants or new builds to the company's natural gas combined cycle fleet. These conclusions are shown in the final slide of their presentation, reproduced below:[43]

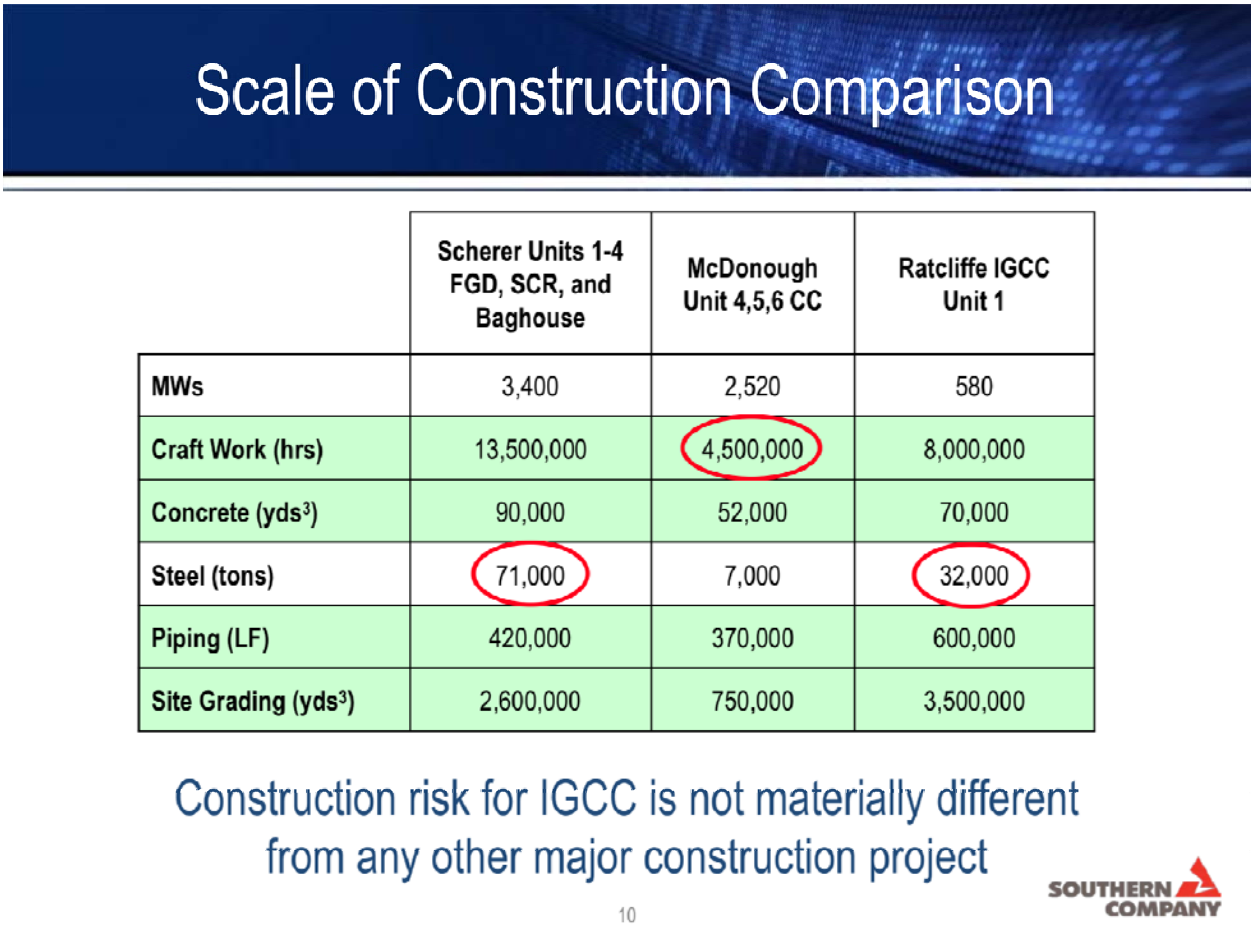

Figure III-2 : IGCC with CCS Construction Risks (source: Southern Company).

According to a February 2012 announcement by Summit Power Group, their proposed 400 MW (gross) IGCC coal power plant in Texas with 90 percent carbon capture will have "firm-price, turnkey EPC [engineering-procurement-construction] contracts that guarantee price, schedule and performance for the integrated coal gasification combined cycle (IGCC) project'

[43] Day, E. and Manual, P, *Plant Ratcliffe Update* (Available at http://files.shareholder.com/downloads/SO/0x0x448822/cc532fc1-beb9-4af2-b48f-f9619ffb918d/Plant Ratcliffe Update.pdf). Attached as Exh.III- 22.

and "a separate, 15-year O&M [operation and maintenance] contract…for the complete, turnkey operation and maintenance of the entire 600-acre facility, including day-to-day operation, and short term and long term maintenance."[44]

Recent studies also show that pre-combustion capture can reduce CO_2 emissions to below 1000 pounds per MWh. CATF analysis of data published by the U.S. DOE in May 2011, indicates that achieving a 1000 pounds CO_2 per MWh (gross) emission level from IGCC would require roughly 30 percent CO_2 capture; achieving 1000 pounds CO_2 per MWh (net) level would require roughly 45 percent capture.[45] Both levels are less stringent than those currently targeted by Southern Company's Kemper IGCC[46] and by other developers of IGCC projects with CCS, such as Summit (90 percent capture) and a proposed "hybrid" IGCC project in Taylorville, Illinois (although it appears this project is unlikely to be built). CATF analysis of the IGCC emissions data in DOE's report are included below. The 25 percent, 45 percent , and 75 percent capture cases use a single stage of syngas 'shift'; achieving the 90 percent capture level may require additional stages.[47]

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[44] *See* http://www.texascleanenergyproject.com/2012/summits-texas-clean-energy-project-reaches-major-milestone-with-signed-epc-and-om-contracts (emphasis added) . Attached here as Exh.III- 23.

[45] CATF analysis of data in DOE/NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, Exhibit 1 and Tables ES-14 and ES-15 (including numerous process configurations and capture levels) (May 27, 2011), DOE/NETL-2011/1498, attached here as Exh. III- 3. CATF has plotted data for IGCC cases "2-D1A"(no capture), "2-D2A", "2-D2B", "2D2C". and "2-D2D" (25 %, 45%, 60%, and 75% capture, respectively, all using one stage of 'shift') and "2-D4A"(90% capture, using two stages of 'shift'). Dashed lines represent a curve fit by CATF between the DOE data points. For an emission rate, read from the vertical axis, the corresponding capture level can be read from the horizontal axis.

[46] *See* Rush, R., *Overview of the Kemper Country and TMEP IGCC Projects Using Transport Integrated Gasification (TRIG™)* (October 10, 2011). Attached as Exh. III- 24.

[47] DOE, NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture,* at ES-15 (May 27, 2011) (DOE/NETl-2011/1498). Attached as Exh. III-3. Figure generated by CATF from DOE/NETL data.

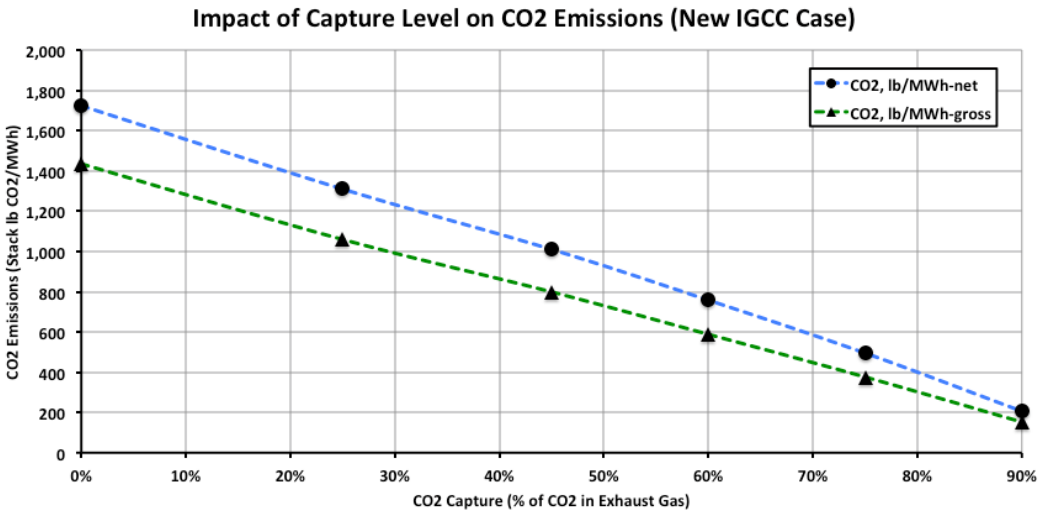

Figure III-3 Source: CATF Plot of Emissions Data (*infra* n. 46).

(b) Post-combustion Capture Systems for Natural Gas and Coal Combustion are Demonstrated and Commercially Available at Large Scale.

Post-combustion capture is based on aqueous solutions of amines (a family of nitrogen compounds similar to ammonia) that are commonly employed in industrial processes outside the power generation industry. These systems have been applied successfully to exhaust from natural gas (including a combined cycle power plant) and coal plants. EPA highlights two technologies in wide use today -- the Fluor Econamine FG process (monoethanolamine or MEA) and the Mitsubishi Heavy Industries KS–1 solvent (which is based upon a sterically hindered amine).[48] But, not included in EPA's record is evidence from other vendors offering post-combustion capture systems including Kerr-McGee/ABB, China's Thermal Power Research Group, and Norway's Aker. PCC projects by Fluor, MHI, and the other firms are summarized in the table below. Some of these projects are quite small. Others are significantly larger. The MHI commercial projects in India (on natural gas plants) are over 400 metric tons per day each, for example,[49] the Fluor commercial project in Massachusetts (on a natural gas plant) was over 300 tons per day, and the Fluor commercial project in Lubbock, TX (on a natural gas plant) was 1000

[48] 77 Fed. Reg. at 22,416 /1.
[49] MHI Project Data available at http://www.mhi.co.jp/en/products/detail/km-cdr_experiences.html, attached here as Exh. III-25.

tons per day.[50] The Searles Valley Minerals project (on a coal plant) in California is over 850 tons per day.[51]

Table III-1 -- Significant Post-Combustion CO_2 Capture Projects[52]

Vendor	**Location**	**Exhaust Stream**	CO_2 **Use**
ABB	Searles Valley, California	Coal Boiler	Chemicals Industry
ABB	Warrior Run, MD	Coal Boiler	Food Industry
ABB	Shady Point, OK	Coal Boiler	Food Industry
TPRI	Shanghai, PRC	Coal Boiler	Food Industry
TPRI	Beijing, PRC	Coal Boiler	Demonstration, Food
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Aonla, India	NG fired SR flue gas*	Urea Production
MHI	Phulpur, India	NG fired SR flue gas*	Urea Production
MHI	Kakinada, India	NG fired SR flue gas*	Urea Production
MHI	Vijaipur, India	NG fired SR flue gas*	Urea Production
MHI	Bahrain	NG fired SR flue gas*	Urea Production
MHI	Phu My, Vietnam	NG fired SR flue gas*	Urea Production
MHI	Fukuoka, Japan	NG fired SR flue gas*	General use
MHI	Abu Dhabi , UAE	NG fired SR flue gas*	Urea Production
MHI	District Ghotoki, Pakistan	NG fired SR flue gas*	Urea Production
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Plant Barry, AL	Coal Boiler	Demo (amine)
Fluor	Bellingham, MA, USA	Gas Turbine Exhaust	Food Industry
Fluor	Lubbock, TX, USA	Natural Gas	Enhanced Oil Recovery

[50] Chapel, D.G. et al., *Recovery of $CO_2$from Flue Gases: Commercial Trends*, at Table 1 (1999) (Available at http://prod75-interl.netl.doc.gov/publications/proceedings/01/carbon_seq/2b3.pdf). Attached as Exh. III-26.

[51] EPRI, *CO_2 Capture and Storage Newsletter*, December 2006, at 1. Attached as Exh. III-27.

[52] Unless otherwise indicated, the MHI project listed here are from http://www.mhi.co.jp/en/products/detail/km-cdr_experiences.html, Fluor projects listed here are from http://www.fluor.com/econamine/Pages/projectsites.aspx, ABB projects are from http://www.ieaghg.org/rdd/gmap/searchresultsgmap.php?keyword=Operational+Large+scale+Project. The Monstad project is described in Appendix 2 of "Request for Interest: Carbon Capture Technology Tests at Available site, TCM DA, Monstad, Norway, Cycle 1". The TPRI projects are described in Best & Levina, Facing China's Coal Future: Prospects and Challenges for Carbon Capture and Storage, at Table 2 and Table 4, available at http://www.iea.org/publications/insights/chinas_coal_future.pdf.

Fluor	Carlsbad, NM	Natural Gas	Enhanced Oil Recovery
Fluor	Santa Domingo, DR	Light Fuel Oil	Enhanced Oil Recovery
Fluor	Barranquilla, Columbia	Natural Gas	Food Industry
Fluor	Quito, Ecuador	Light Fuel Oil	Food Industry
Fluor	Brazil	NG / Heavy Fuel Oil	Food Industry
Fluor	Rio DeJanero, Brazil	Steam Reformer	Methanol Production
Fluor	Sao Paulo, Brazil	Gas Engine Exhaust	Food Production
Fluor	Argentina	Steam Reformer	Urea Plant Feed
Fluor	Spain	Gas Engine Exhaust	Food Industry
Fluor	Barcelona, Spain	Gas Engine Exhaust	Food Industry
Fluor	Bithor County, Romania	Heavy Fuel Oil	Food Industry
Fluor	Cairo, Egypt	Light Fuel Oil	Food Industry
Fluor	Israel	Heavy Oil Boiler	Food Industry
Fluor	Uttar Pradesh, India	NG Reformer Furnace	Urea Plant Feed
Fluor	Sechuan Province, PRC	NG Reformer Furnace	Urea Plant Feed
Fluor	Singapore	Steam Reformer	Food Industry
Fluor	San Fernando, Philippines	Light Fuel Oil	Food Industry
Fluor	Manila, Philippines	Light Fuel Oil	Food Industry
Fluor	Osaka, Japan	LPG	Demo Plant
Fluor	Yokosuka, Japan	Coal/Heavy Fuel OIl	Demo Plant
Fluor	Botany Australia	Natural Gas	Food Industry
Fluor	Alton, Australia	Natural Gas	Food Industry
Alstom	Mountaineer, WV	Coal Boiler	Demo (ammonia)
Alstom	Mongstad, Norway	NG turbine/refinery	Demo (ammonia)
Aker	Mongstad, Norway	NG turbine/refinery	Demo (amine)

* MHI describes these as "post-combustion" capture projects, and the exhaust gas from which the CO_2 is separated is quite similar to conventional combustion gases (68% nitrogen, 8% CO_2, balance mostly water).[53]
+ Licensing of the PCC technology developed by Kerr-McGee[54] was transferred to ABB in 1990.

All of these vendors above, except perhaps for ABB, offer commercial PCC systems for coal power projects. In fact, Fluor has said "[t]he Econamine FG+ technology is ready for full

[53] Kamijo, et al., *Recent technology development of KS-1 CO2 recovery process* (May, 2004) (Available at http://www.netl.doe.gov/publications/proceedings/04/carbon-seq/038.pdf). Attached as Exh. III-29.
[54] Herzog, H. J., *The Economics of CO2 Separation and Capture*, Table 1, Note 1. Attached as Exh. III-30.

scale deployment in: Gas- and Coal-fired Power plants,"[55] and recent commercial activity supports their assertion. A January 2012 front-end engineering and design (FEED) study for Tenaska Trailblazer Partners LLC for a 760 MW (gross) pulverized coal power plant with 85 to 90 percent carbon capture to be located in Texas concluded that "Tenaska and Fluor achieved the goals of the [carbon capture plant] FEED study, resulting in ... establishment of performance guarantees which, after the addition of an appropriate margin, were consistent with the expected performance in Fluor's indicative bid."[56] Regarding their post-combustion CO_2 capture, technology, MHI says "[i]t must also be reinforced that MHI is NOW ready to provide large scale, single train commercial PCC plants for natural gas fired installations (with completed basic design for a 3,000 [tons per day] plant train) and intends to leverage this experience for application to large scale CO_2 capture for coal fired flue gas streams."[57]

Amine-based post-combustion CO_2 capture technology also can be sized to capture essentially any fraction of the flue gas from a coal power plant, from 0 percent up to 70 percent and beyond. DOE's projected relationship between CO_2 emission rates and CO_2 capture levels for PCC is included below.[58]

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[55] Reddy, S., *Econamine FG Plus Technology for CO2 Capture at Coal-fired Power Plants* (August 2008). Attached here as Exh. III-31.

[56] Tenaska Trailblazer Partners, LLC, *Report to the Global CCS Institute: Final Front-End Engineering and Design Study Report*, at 69 (Available at http://cdn.globalccsinstitute.com/sites/default/files/publications/32321/traiblazer-front-end-engineering-and-design-study-report-final.pdf). Attached here as Exh. III-32.

[57] MHI, FW, and E.On, *Design Basis for CO2 Recovery Plant, Kingsnorth Carbon Capture & Storage Project, FEED report*, (2011) (emphasis in original). Attached here as Exh. III-33.

[58] DOE, NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, Tables ES-14 and ES-15 (May 27, 2011) (DOE/NETl-2011/1498) (data includes numerous process configuration and capture levels). Attached as Exh. III-3. From DOE/NETL data, CATF has plotted data for supercritical pulverized coal cases "0", "1A", "1B", "1C". and "1E" (0%, 30%, 50%, 70%, and 90% capture respectively). Dashed lines represent a curve fit by CATF between the DOE data points. For an emission rate read from the vertical axis; the corresponding capture level can be read from the horizontal axis.

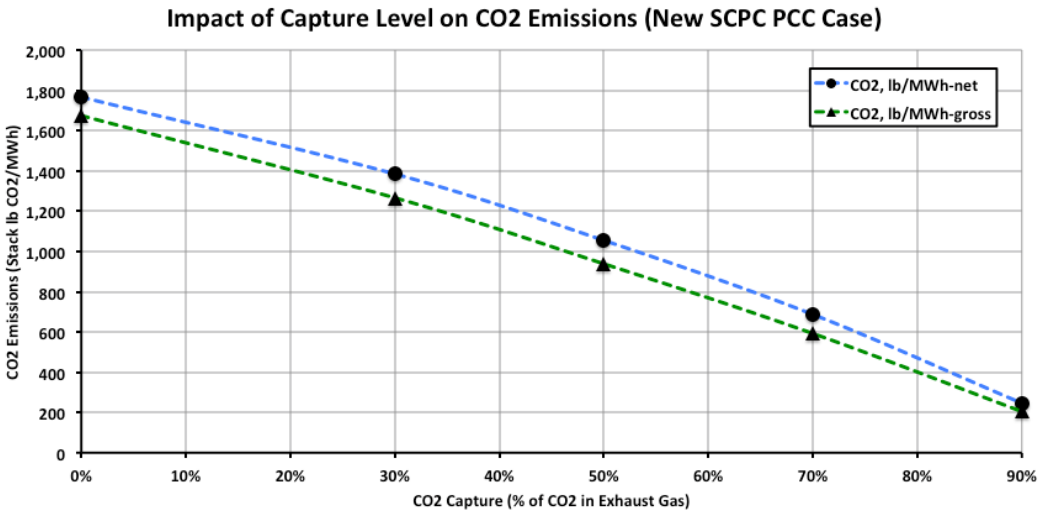

Figure III-4. Emissions and Capture Levels for SCPC (source: CATF from DOE/NETL).

(c) Dedicated CO_2 transport pipelines are available, and build out to support additional demand for CO_2 transportation will be achieved at reasonable costs.

There are presently approximately 4000 miles of CO_2 pipeline connecting naturally mined and anthropogenic sources of CO_2 with enhanced oil recovery projects.[59] In total, this system now carries approximately 50 million metric tons per year of CO_2 throughput. The Denbury "Green" pipeline, completed in 2009, extends from Jackson MS to Houston TX, collecting and delivering both naturally mined and anthropogenic CO_2. The projected routes for the future Midwest pipeline include a 320-mile long extension of the Denbury Green pipeline to southern Illinois. The Midwest extension will connect anthropogenic sources to fields in Mississippi, Louisiana, and Texas. There are half a million miles of natural gas and hazardous liquids pipelines rights-of-way, of which some routes might also provide rights-of-way for the build-out of CO_2 pipeline network.

The modeling work of Battelle's Joint Global Change Research Institute suggests that building out a CO_2 pipeline system would be a reasonable task under two hypothetical climate

[59] Advanced Resources International, *U.S. Oil production potential from accelerated deployment of carbon capture and storage* (2010) (Available at http://www.adv-res.com/pdf/v4ARI%20CCS-CO2-EOR%20whitepaper%20FINAL%204-2-10.pdf). Attached as Exh. III-36.

stabilization policies that would limit atmospheric build up of CO_2 levels to 450 or 550 ppm. [60] Between 11,000 and 23,000 additional miles of CO_2 pipelines might be needed by 2050 in these two cases. From 2010-2030 the analysis estimated that a few hundred to less than 1,000 miles per year. The natural gas pipeline system from 1950-2000 grew at rates that were "far higher" than expected under Battelle's modeled scenarios. The paper concludes: "...the need to increase the size of the existing dedicated CO_2 pipeline system should not be seen as a major obstacle for the commercial deployment of CCS technologies in the United States."[61]

In another analysis, Advanced Resources Inc. has estimated that three 800 mile-long pipelines could result in the storage of 30 years of Ohio River Valley EGU coal plant CO_2.[62] And Elliott and Celia (2012)[63] have analyzed the storage resources in the proximity of the largest U.S. CO_2 sources in the U.S. – they report that large sources emitting 2.2 Gigatons of CO_2 are located within 20 miles of a saline reservoir.

EPA has estimated the interstate transportation cost for CO_2 storage using the GeoCAT (Geosequestration Cost Analysis Tool) model, supporting the Class VI Underground Injection Control Rule.[64] The GeoCAT analysis includes unit cost specification for saline reservoirs, depleted oil and gas fields, EOR (including site characterization, well construction, operations, monitoring, financial responsibility. The EPA analysis also determined that the total cost of geologic sequestration (without taking into consideration credits for byproducts such as EOR) ranged from $2.84 to $28.12 per metric ton of CO_2 stored depending on reservoir characteristics. In an EOR setting, offsetting these costs with the value of CO_2 (which we understand to be roughly on order of $15-40 per ton depending on the basin) would, in some cases fully offset this

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[60] Dooley, J.J., Dahowski, R.T, and Davidson, C.L., *Comparing existing pipeline networks with the potential scale of future U.S. CO_2 pipeline networks. Energy Procedia, GHGT9* (2009) (Available at: http://www.sciencedirect.com/science/article/pii/S1876610209002100). Attached here as Exh. III-37.

[61] *Id.*

[62] Kuuskraa, V., Advanced Resources International, *Challenges of implementing large-scale CO_2 enhanced oil recovery with carbon capture and storage* (2010) (Available at http://web.mit.edu/mitei/docs/reports/eor-css/kuuskraa.pdf). Attached as Exh. III-38.

[63] Elliot T.R. and Celia M.A., *Potential restrictions for CO2 sequestration sites due to shale and tight gas productioni,* 46 Environmental Science and Technology, 4223-4227 (2012). Attached as Exh. III-39.

[64] EPA, *Documentation for EPA Base Case v.4.10 using the Integrated Planning Mode*. Chapter 6 CO_2 Capture, Transport, Storage (2010) (Available at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html). Attached as Exh. III-40.

cost, or even produce net revenue. Vidas *et al.* conclude that for the estimated 3.4 trillion tons of storage capacity in the U.S.[65] half of the saline capacity is available at less than $15 per ton CO_2 (all costs included). Of that storage capacity, over a half trillion metric tons could be utilized at a cost of less than $5 per ton of CO_2.[66]

(d) Current information about Domestic and International Integrated CCS projects Provides Support for reliance on CCS as a BSER for this industry.

(i) The following U.S. integrated CCS projects already have or have proposed to integrate capture and geologic storage over the next 8 years.

- **Southern Company Plant Barry-Denbury Cintronelle Field Integrated Capture, Transport and Storage Project:** This important project demonstrates the availability of fully integrated carbon capture and geologic storage technology in the Gulf Coast. Alabama Power's Plant Barry is the site of the first fully integrated CO_2 capture-transportation and storage test in the U.S. which is a project of Southern Company, the Southern States Energy Board, EPRI and Advanced Resources Inc. CO_2 is captured at Plant Barry with a Mitsubishi Heavy Industries amine technology and transported 12 miles by pipeline to Denbury Resources' Cintronelle oilfield. The plant began capturing CO_2 at a rate of up to 650 tons per day in the 4th quarter of 2011, amounting to a target of approximately 50,000 tons per year.[67] Alabama Power has constructed a pipeline from Plant Barry to Denbury's nearby Cintronelle oilfield where injection of the captured CO_2 into a saline aquifer below the oil field will commence in mid 2012.
- **Hydrogen Energy/ Occidental Petroleum Elk Hills, California:** Hydrogen Energy of California will capture 90 percent of the CO_2 (2 million tons per year) from a 390 MW power plant (250 MW net) and send it via a 5 mile-long pipeline to Occidental Petroleum's Elk

[65] This represents the DOE storage capacity estimate at the time the paper was published in 2009, but that has since been updated.
[66] Vidas, Harry, et al., *Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation Energy Procedia*, Vol. 1, Issue 1, at 4281-88 (February 2009). Attached as Exh. III-41.
[67] Koperna, et al., *The SECARB anthropogenic test: the first U.S. integrated CO2 capture, transportation and storage test* (2011) (Available at: http://www.adv-res.com/pdf/Pitt_Coal_Conference_Paper_FINAL.pdf). Attached as Exh. III-42.

Hills Oil field for combined EOR and geologic storage near Bakersfield, CA.[68] Plant operation is expected to commence in 2016.

- **Tenaska Taylorville (new information about the extent of Midwestern sequestration resource):** As originally proposed, Tenaska's Taylorville Christian County Generation project in Illinois is a 600 MW IGCC project designed to achieve 65 percent CO_2 capture. [69] While the project is now on hold, the permit process resulted in a detailed analysis of the saline storage in the Mt. Simon Formation that describes and supports the availability of geologic carbon storage in the Midwestern U.S.[70]

  CATF reviewed the information in the Taylorville class VI permit application. It demonstrates that the Mt. Simon has the thickness, depth, permeability and cap rock to perform as an excellent low-risk saline storage aquifer at this site. Several of its geological characteristics suggest that the Mt. Simon Formation has the capacity to hold substantial volumes of CO_2: its thickness, its porosity and permeability, its depth, and the multiple overlying thick confining layers that ensure that sequestered CO_2 volumes will permanently remain secure. The Mt. Simon Formation is a sequence of quartz sandstone and conglomerate estimated at 1,100-1,300 feet thick in the Taylorsville area and is thought to have formed as a braided stream deposit, which is known to petroleum geologists as a geologic environment which generally results in good matrix permeability and porosity—characteristics necessary and suitable for the injection and containment of large volumes of CO_2. Taylorville Energy Center's permit application further shows that there are no discernable updip faults in the formation, based on the seismic analysis, along which CO_2 could migrate, although resolution of the seismic line may not permit adequate level of detail to view small structures. Seismic activity in the vicinity of the site is deemed to be low-risk with only one known recorded quake at Richter magnitude 3.2.

  The TEC application also states that Mt. Simon Formation already is extensively developed for underground disposal and storage of other kinds, permitted through UIC Class

[68] *See*: http://sequestration.mit.edu/tools/projects/heca.html. Attached as Exh. III-43.
[69] *See*: http://sequestration.mit.edu/tools/projects/taylorville.html. Attached as Exh. III-44.
[70] Tenaska Taylorville Christian County Generation EPA Class VI UIC Permit Application, September 20, 2011, *available at* http://www.epa.gov/r5water/uic/tec/pdfs/tec-permit-appl-201109.pdf. Attached as Exh. III-83.

I wells in Illinois and Indiana. The Mt. Simon Formation itself has the potential to be an excellent CO_2 reservoir candidate because of its physical characteristics, but also because there are overlying multiple confining formations (impermeable CO_2 traps) that would prevent CO_2 movement into a source of drinking water, or to the atmosphere at the earth's surface in the unlikely event that CO_2 were to migrate out of the Mt. Simon Formation. The thick Eau Claire Formation shale, at 5,000 feet depth, is the primary confining unit. Above the Eau Claire, the Knox Group Formations are tight dolomitic carbonate rocks that also can provide a barrier to flow should the primary (Eau Claire) seal fail. Above the Knox Group are two impermeable shale formations below shallow sources of ground water that have been identified in the UIC Class VI permit application as secondary seals: the Maqouketa and New Albany Formations, located at depths of about 2,500 and 1,800 feet. The Maquoketa shale is roughly 200 feet thick and the New Albany Formation is roughly 125 feet thick.

(ii) The following information provides status updates about international integrated CCS projects that already have or have proposed to integrate capture and geologic sequestration over the next 8 years.

- **Dakota Gasification/Weyburn, Saskatchewan, Canada:** Weyburn-Midale oil field is a CCUS enhanced oil recovery project located in Saskatchewan Canada and is the receptor site for captured CO_2 from the Beulah Dakota gasification site in the U.S.[71] Over the life of the field, approximately 26 million tons (net) will be stored at Weyburn as a part of enhanced oil recovery at the field, more than half of which has already been injected (>17 million tons). The IEAGHG in conjunction with Canada's non-profit Petroleum Technology Research Centre (PTRC), has implemented a monitoring testing program to investigate the most effective methods for ensuring CO_2 injected for EOR remains sequestered. In 2011 it was alleged that CO_2 from the project was leaking at the surface at Kerr Farm. Subsequent independent, peer-reviewed analysis by the University of Texas suggests, however, that the methane in the soils at the farm are of biologic and not geologic origin.[72]

[71] See: http://www.ieaghg.org/docs/general_publications/weyburn.pdf . Attached as Exh. III-45.
[72] Romanak, *Analysis of Gas Chemistry at the Kerr Site*, IPAC Publication (2012). Attached as Exh. III-46.

- **CO2CRC Otway Project, Australia:** The Otway project is operated by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). Supported by the Australian federal government, U.S. DOE successfully tested storage capacity and monitoring of 65,000 metric tons of CO_2 injected into subsurface depleted natural gas fields. [73] The effort provides new and substantial information on injection and tracking of CO_2, and included reservoir modeling, risk assessment, and monitoring and verification. The project incorporated air, water and soil monitoring methods confirming the confinement of the CO_2 to the intended storage zone. The project concluded that depleted gas fields can provide significant CO_2 storage volumes.

- **In Salah, Algeria:** The BP, Statoil, Sonatrach, US DOE, EU Directorate of Research In Salah sequestration project is located in the Sahara desert in Algeria and, since its inception, over 3 million metric tons of CO_2 captured from a BP natural gas processing plant have been injected in the saline field at a rate of up to 1.2 million tons per year.[74] The CO_2 is injected two kilometers deep into the 20 meter thick Krechba Carboniferous sandstone formation via 3 horizontal wells. The sandstone has a 12 percent porosity and 10 mD permeability (a relatively tight formation but similar to many formations around the world). Monitoring implemented at the In Salah field has verified the integrity of the CO_2 sequestration system during the injections and demonstrated the usefulness of several monitoring tools to track subsurface CO_2. This project demonstrates the successful injection of a commercial volume of CO_2 and its sequestration from atmospheric release.

- **Sleipner, Norway, North Sea:** The Sleipner sequestration project is located 250 kilometers offshore in the North Sea where one million tons of CO_2 separated at a natural gas processing

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[73] *See* http://www.carboncapturejournal.com/displaynews.php?NewsID=883&PHPSESSID=gvtdi1gmspkmdlvtqklcl9dfr4, attached here as Exh. III-47.

[74] *See* Wright, *In Salah CCS* (2010), attached as Exh. III-50, and http://www.statoil.com/en/technologyinnovation/newenergy/co2management/pages/insalah.aspx, attached here as Exh. III-51, and http://www.bp.com/sectiongenericarticle.do?categoryId=9033334&contentId=7061356, attached here as Exh. III-52.

plant have been injected into the Utsira Sandstone per year since 1996. [75] Over 17 million tons have been injected over the life of the project to-date. The Utsira is a 200-250 meter thick formation –with an overlying 800 meter thick caprock formation that is predicted to be able to contain 600 billion tons of CO_2. Monitoring has verified that CO_2 has not leaked upward into other rock formations. The Sleipner project demonstrates the successful long-term injection of commercial volumes of CO_2 into a saline reservoir, particularly in an offshore location.

- **Snohvit, Norway, North Sea:** The Snohvit saline sequestration project is operated by Norwegian Statoil, and has sequestered approximately 0.7 million metric tons of CO_2 per year separated from a natural gas processing plant, into the Tubaen sandstone Formation since 2008 at a subsea depth of about 2.5 kilometers.[76] EU-financed monitoring accompanies this project. The project is ground-breaking in that it is the first to operate without offshore installations. The capacity of the sandstone was less than expected so Statoil is testing well stimulation techniques such as hydraulic fracturing to improve capacity. The caprock that has kept the natural gas being produced in place for millennia is also expected to keep the CO_2 secure.

- **GFZ Storage and Monitoring Project, Ketzin, Germany:** A multi-year pilot CO_2 injection research program in Ketzin, Germany, a project of GFZ has, since 2008, successfully injected approximately 60,000 tons of CO_2 from a hydrogen production plant and the Schwarze Pumpe coal oxy-combustion pilot plant, at a depth of between 630-650 meters in the Stuttgart Formation, a saline aquifer in the north Germany Basin.[77] The aquifer

[75] *See* http://sequestration.mit.edu/tools/projects/sleipner.html, attached here as Exh. III-53, and http://www.statoil.com/en/technologyinnovation/newenergy/co2management/pages/sleipnervest.aspx, attached here as Exh. III-54.
[76] *See* http://sequestration.mit.edu/tools/projects/snohvit.html, attached here as Exh. III-55 and http://www.statoil.com/en/technologyinnovation/newenergy/co2management/pages/snohvit.aspx , attached here as Exh. III-56.
[77] See: http://sequestration.mit.edu/tools/projects/ketzin.html, attached here as Exh. III-57 and Martens *et al*., *Europe's longest-operating on-shore CO2 storage site at Ketzin, Germany: a progress report after three years of injection*, Environ. Earth Sci. (April 2012) (DOI 10.1007/s12665-012-1672-5), attached as Exh III-58.

is overlain by a 210 meter thick shale cap rock. Several important outcomes of this project include demonstration that: 1) geochemical and geophysical monitoring are capable of detecting small quantities of CO_2, 2) geophysical tools are capable of imaging CO_2 in the subsurface, 3) the injection of CO_2 has had no adverse interactions with the reservoir rock containing the CO_2, and 4) simulations were able to predict the fate of injected CO_2.

- **European CO_2 Test Centre, Mongstad, Norway:** The Mongstad CCS facility, started in May 2012, a combined effort of Statoil, Sasol, Shell and the Norwegian government.[78] It is a 2-phase project. In the first phase, already underway, 100,000 tons per year will be captured from an existing natural gas-fired combined heat and power facility and an existing oil refinery using a flexible arrangement of both amine and chilled ammonia post-combustion capture process. The flexible approach allows for use of different combinations of the inlet gases and capture processes for testing[79] using a post-combustion capture amine plant (20,000 tons) and Alstom chilled ammonia plant (80,000 tons) at the Mongstad refinery, and released. In phase 2, slated for 2016, 1.5 millions tons per year are proposed to be captured and sequestered in a saline aquifer.

- **Belchatow, Poland:** Poland's PGE Elektrownia and Alstom are constructing a two-stage carbon capture and saline storage project in Belchatow, Poland.[80] The operation is slated to go online in 2014 (phase 1) and 2015 (phase 2). During phase 1, the project is proposed to capture approximately 100,000 tons per year from a 250 MW slipstream. In phase 2, 1.8 million metric tons will be captured from an 858 MW unit. The captured CO_2 will be sequestered in a saline aquifer within the Wojszyce onshore salt structure.[81]

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[78] *See* http://sequestration.mit.edu/tools/projects/statoil_mongstad.html . Attached as Exh. III-59.
[79] *See* Appendix 2 of "Request for Interest: Carbon Capture Technology Tests at Available site, TCM DA, Mongstad, Norway. Cycle 1", attached here as Exhibit III-28.
[80] *See* http://www.pgesa.pl/en/PGE/PressCenter/PressInformation/Pages/PGEDecidestoContinueCCSProject.aspx, attached as Exh. III-60, and http://sequestration.mit.edu/tools/projects/belchatow.html, attached as Exh. III-61.
[81] *See* Krzywiec, P., *Triassic Evolution of the Klodawa salt structure: basement-controlled salt tectonics within the mid-Polish trough (central Poland)*, Geological Quarterly 48 (2) 123-134

- **Don Valley Power Project, Stainforth, UK:** The Don Valley Power project, one of the UK's and EU's CCS projects, is a 650 MW IGCC power plant which will capture and inject up to 5 million tons per year or 90 percent of the power station's CO_2 emissions for offshore EOR in the North Sea.[82] The project continues to move forward with construction planned for 2013, pending financial support, with operations to commence in 2016.

- **Boundary Dam, Saskatchewan, Canada**: This SaskPower project will add post-combustion capture to a 110 MW EGU (Unit 3 at Boundary Dam Power Station).[83] SaskPower received approval from the Saskatchewan Government to build the project in April 2011 and construction is underway. The project will capture 90 percent of the CO_2 from the 110 MW unit which is approximately 1 million tons per year.[84] Operation of the plant will begin in 2014. CO_2 capture from Boundary Dam will be injected at the Sasketchewan Aquistore facility.

- **Aquistore, Saskatchewan:** The IEAGHG's "Aquistore Program," a collaborative industry and government program, is being operated by Canada's non-profit Petroleum Technology Research Centre (PTRC).[85] Aquistore is a 3-kilometer deep, 100 meter thick Cambro-Ordovician age saline sandstone reservoir located in the Williston Basin in Saskatchewan, Canada.[86] Aquistore is set to be drilled and accept CO_2 from a nearby refinery in 2012-2013

(2004) (Available at: http://gq.pgi.gov.pl/gq/article/viewFile/7338/5988). Attached as Exh. III-62.

[82] See: http://www.2coenergy.com/don_valley_power_project.html, attached as Exh. III-63 and http://sequestration.mit.edu/tools/projects/don_valley.html, attached as Exh. III-64.

[83] http://www.saskpower.com/sustainable_growth/assets/clean_coal_information_sheet.pdf. Attached as Exh. III-65.

[84] Global CCS Institute, *The Global Status of CCS: 2011*, pp. 25, 102 (2011). Attached as Exh. III-66.

[85] For more information on Aquistore, see: http://www.google.com/url?sa=t&rct=j&q=aquistore&source=web&cd=2&ved=0CF0QFjAB&url=http%3A%2F%2Fwww.ifpenergiesnouvelles.com%2Fcontent%2Fdownload%2F67983%2F1473837%2Ffile%2F26_Whittaker.pdf&ei=x2ixT7KoBKig6QHCmaGICQ&usg=AFQjCNH-h5UNO2_dyK9_8-yDUxK1zdUwkQ. Attached as Exh. III-48.

[86] See: http://www.ptrc.ca/aquistore_overview.php. Attached as Exh. III-49.

and at the end of 2013 captured CO_2 from the SaskPower Boundary Dam project two kilometers away, where it will most likely become the largest commercial and fully integrated CO_2 capture and storage facility in the world.

(2) CCS adds acceptable costs to power plants, and additional development activities will reduce CO_2 capture costs to improve performance.

Recent analysis by DOE suggests that the electricity price impacts of partial CCS meeting EPA's proposed emission standard would not be unreasonable, even without considering revenue for sales of CO_2 for EOR. Compared to an uncontrolled IGCC, the levelized cost of electricity from an IGCC emitting 1010 pounds of CO_2 per MWh (net) would increase by about 19 percent; for a supercritical pulverized coal power plant emitting 1055 pounds of CO_2 per MWh (net) the relative increase over an uncontrolled baseline is somewhat higher, about 43 percent.[87] These estimates include the costs of compressing, transporting, sequestering, and monitoring the captured CO_2.[88]

Innovation and experience are expected to reduce these costs significantly over time, as EPA has noted. In June, 2012, for example, General Electric of the U.S. and Sargas of Norway announced that they "have launched a new technology for capturing carbon dioxide emissions from power plants that they say will be much cheaper than rival processes and commercially viable without any government subsidy. The two companies said that they have formed an alliance to sell gas-fired plants that would capture 90 percent of their output of carbon dioxide. They expect to be able to supply carbon dioxide at prices that are much lower than the capture costs faced by other prototype projects now under development, and even well below the $30 per [metric ton of CO_2] paid in the oil industry in Texas."[89] The companies plan for the technology to be used initially in two plants, one on the coast of Norway and one along the Gulf of Mexico.

Additionally, EPA correctly identifies that "significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control

[87] DOE, NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, at ES-14 and -15 (May 27, 2011) (DOE/NETl-2011/1498). Attached as Exh. III-3.
[88] *Id.* at 1.
[89] Ed Crooks, *GE Launches New Carbon Capture Technology*, Financial Times (June 19, 2012). Attached as Exh. III- 67.

technology."[90] In addition to the factors cited by EPA, the cost of capture may fall as Chinese post-combustion capture and pre-combustion gasification systems become available in the West. For example, on February 13, 2012, Duke and Huaneng announced plans for a feasibility study to retrofit Duke's Gibson 3 station with post-combustion capture technology developed by Huaneng for the Shidonkou power plant near Shanghai.[91] The feasibility study will be funded by the U.S.-China Clean Energy Research Center. Huaneng estimates the cost of their technology to be about $39/ton; according to Duke's Chief Technology Officer, that is about one-third the cost of similar technology in the U.S.[92] The feasibility study will be completed at the end of 2012.

(3) Ample U.S. Sequestration Is Available to Support Reliance On CCS as BSER in This Rulemaking.

Decades of experience in enhanced oil recovery (EOR), wastewater injection, and natural gas storage, combined with very large geologic CO_2 storage capacities in the U.S., provide confidence that long term CO_2 storage is both available and a best system of emissions reductions (BSER).[93] While commercial-scale deep saline CO_2 injection and storage experience is more limited, deep geologic injections and storage of wastewater, natural gas and for enhanced oil recovery (EOR) are commonplace in the U.S. CO_2 injection technology is grounded in a half-century of oil industry CO_2 management expertise. Moreover, natural gas companies routinely use deep geologic storage for natural gas reserves at over 400 sites in the U.S. injecting and storing natural gas in saline aquifers, depleted natural gas reservoirs and salt deposits. Including geologic wastewater injections, billions of tons of fluids are injected each year in the U.S.[94] Capacities for deep geological storage of CO_2 amount to hundreds, if not thousands of years, of present day CO_2 emissions rates. The U.S. Department of Energy's North American Carbon

[90] 77 Fed. Reg. at 22,416 /1.
[91] See http://www.duke-energy.com/news/releases/2012021301.asp. Attached as Exh. III-68.
[92] *Id.*
[93] Benson, S., *Monitoring carbon dioxide sequestration in deep geological formations for inventory verification and carbon credits*, Society of Petroleum Engineers SPE paper 102833 (2006) (Available at http://www.energy.utah.gov/government/docs/forum/dec2006/spe102833.pdf). Attached as Exh. III-69.
[94] Wilson, E. *et al.*, *Regulating the ultimate sink: managing the risks of CO2 storage*, 37 Environmental Sci. & Tech 3476-3483 (2003). Attached as Exh. III-70.

Storage Atlas (NACSA) released in 2012 estimates that there are approximately 500 years of storage capacity for CO_2 emissions in North America.[95] Geologic formations that can accept CO_2 are widespread in the U.S., particularly in states that are rich in coal reserves. This means that where power plants are built close to coal resources, they will also be proximal to deep geologic storage resources. Furthermore, substantial capacity and transportation and injection infrastructure are currently available in EOR fields in the parts of the Rocky Mountains, Midwest, Southeast and parts of California. Cooperative research in the western U.S. is wisely evaluating development of storage resources near existing CO_2 pipelines.

Secure geologic storage not only requires injection technology and capacity but it means careful site selection and surveillance to ensure that injected volumes remain out of the atmosphere and groundwater resources. Department of Energy (DOE) National Energy Technology Laboratory (NETL) Research Carbon Sequestration Partnerships (RCSP) have developed protocols and experience in site characterization, monitoring, verification and accounting (MVA) to ensure that injected CO_2 remains confined in the subsurface and does not migrate and threaten aquifers or escape into the atmosphere.[96] Federal regulations also now govern geologic CO_2 storage. EPA Underground Injection Control Program (UIC) Class VI[97] rules were finalized in 2010 to protect fresh water aquifers during saline geologic storage, and UIC Class II rules[98] are designed to protect aquifers during EOR. EPA's Greenhouse Gas Reporting rule subpart RR lays out a framework for monitoring, reporting and verification (MRV) of CO_2 volumes stored.[99] CO_2 brine injection experience over the past ten years and combined with industry experience in EOR, over the past decade demonstrate that today's

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[95] Press Release: "Energy Department Announced New Mapping Initiative to Advance North American Carbon Storage Efforts" (May 1 2012) (Available at http://energy.gov/articles/energy-department-announces-new-mapping-initiative-advance-north-american-carbon-storage. The 2012 North American Carbon Storage Atlas is available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf. Attached as Exh. III-71.

[96] NETL, *Monitoring, verification and accounting of CO2 stored in deep geologic formations* (2010) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf). Attached as Exh. III- 72.

[97] 40 C.F.R. Part 144.

[98] 40 C.F.R. Part 146.

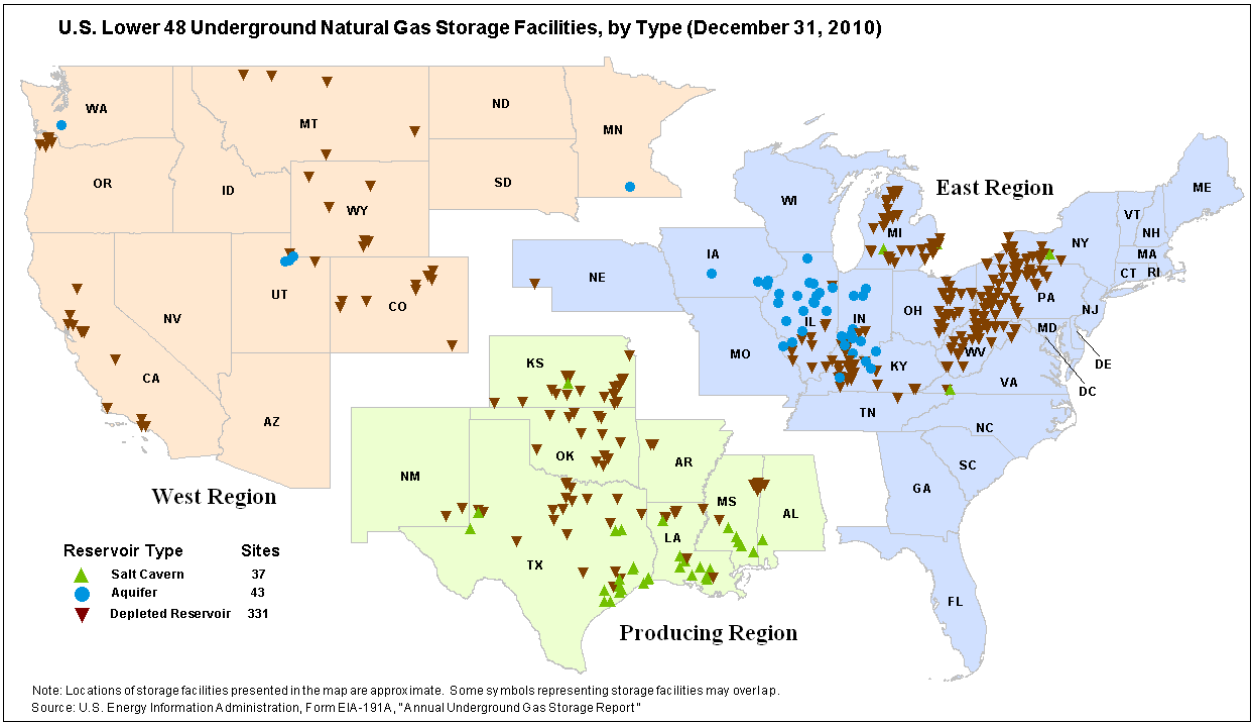
[99] 40 C.F.R. §98.440.

monitoring, verification and accounting methods can track and adequately account CO_2 in the subsurface.

(a) Ongoing Experience with Natural Gas Storage Offers Ample Evidence that Storage Technology is Demonstrated and Commercially Available At Scale.

The natural gas industry offers an excellent example of successful and complete long-term storage of gas from atmospheric release. Over 2.7 trillion cubic feet of natural gas are stored in subsurface aquifers, depleted natural gas fields and salt domes.[100] In many cases, natural gas storage occurs in similar geologic settings as offer potential for geologic CO_2 storage. The map in Figure III -5 illustrates the geographic diversity of existing natural gas storage sites in the U.S. [101]

Figure III-5: U.S. Energy Information Administration map of natural gas storage sites in the U.S. (2010).



[100] U.S. Energy Information Administration. At: http://ir.eia.gov/ngs/ngs.html. Attached as Exh.III-73.

[101] U.S. Energy Information Adminsitration map at: http://205.254.135.7/cfapps/ngqs/images/storage_2010.png. Attached as Exh.III-74.

(b) Current data and experience in the enhanced oil recovery industry demonstrates the commercially available capacity to receive and store anthropogenic CO_2 today.

Deep geologic CO_2 injections have been taking place on a commercial scale and commercial basis for over 4 decades.[102] In fact, the successful first experimental CO_2 flooding (injections) in U.S. oil fields dates back nearly half a century, having taken place first in 1964 at the Mead Strawn Field near Abilene Texas.[103] Results from those early tests indicated that over 50% more oil was produced using CO_2 than by water flooding.[104] The first successful commercial-scale CO_2 flooding took place forty years ago in January 1972 at the SACROC field in west Texas. The CO_2 for the project was supplied from the Canyon Reef pipeline and sourced by anthropogenic CO_2 separated at the Val Verde gas plant. In fact, nearly four decades of CO_2 injections have been undertaken at SACROC with no relative harm to the overlying freshwater aquifer. [105] In 2008, there were 105 CO_2 EOR projects with approximately 13,000 CO_2 injection wells[106] injecting about 50-60 million tons of CO_2.[107] Approximately eighty percent of the CO_2 used in EOR operations is now naturally mined for existing CO_2 deposits, and transported by pipelines to the oil production fields where it is used.[108] According to API, on a daily basis, over 2 billion cubic feet of CO_2 are presently injected for tertiary EOR producing a quarter million barrels of oil. This long experience with a commercial technology, and the current existence of the infrastructure supporting it, provides further evidence and support for its use in sequestering anthropogenic CO_2 captured from U.S. EGUs.

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[102] API Background Report: *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2-EOR) Injection Well Technology* (Available at: http://api.org/environment-health-and-safety/environmental-performance/~/media/D68DE1954B8E4905A961572B3D7A967A.ashx). Attached as Exh.III-75.
[103] *Id.*
[104] *Id.*
[105] Smyth, R., Presentation: *SACROC EOR and Sequestration Demonstration*. Attached as Exh.III-76.
[106] Meyer, J., *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology*. Prepared for American Petroleum Institute. Attached as Exh.III-75.
[107] NETL, *Improving domestic energy security and lowering CO2 emissions with "next generation" CO2 enhanced oil recovery* (2011) (Available at http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf). Attached as Exh.III-77.
[108] *Id.*

In the process of CO_2 flooding for EOR, CO_2 is injected, mixes with oil and is produced with the oil. The CO_2 in the oil is separated at the surface at a separation facility then it is compressed to a supercritical state and recycled for reinjection. The vast majority (all but a few percent) remains isolated from atmospheric release during production and after production activities are completed. While a substantial proportion of the injected CO_2 is produced with the oil, and recycled again for additional production, it is contained within the production system, and as well, much of the injected CO_2 remains trapped in the formation. These CO_2 volumes remain in the reservoir permanently via several mechanisms, including capillary, structural and stratigraphic trapping.

Moreover, historically, purchased CO_2 represents 33-68 percent of the total cost of EOR operations,[109] so there already exists in this industry incentive to track and minimize CO_2 losses. In most places, EOR operators take great care to ensure that CO_2 is not vented to the atmosphere after it is produced, except in the case of a temporary shutdown. As a result, the original "purchased volume" of CO_2 delivered onsite progressively and asymptotically approaches the original volume of CO_2 purchased is preserved for long-term storage in the formation.

The EOR industry therefore now provides available, commercial scale technology, infrastructure and capacity for long-term storage of large volumes of CO_2, with only modest changes from business-as-usual required to satisfy EPA monitoring and reporting protocols, including changes related to injection site selection, monitoring surveillance and CO_2 accounting efforts.[110] In fact, the U.S. DOE's "low" estimates for sequestration volumes available through this method projects that approximately 136 billion metric tons of CO_2 could be permanently sequestered in EOR fields. And, the Gulf Coast Carbon Project estimates that there are 3,549 oil and natural gas reservoirs in the Gulf Coast region where opportunity exists to use anthropogenic CO_2 first for EOR, and then for high volume storage once production is complete, in non-productive formations below the primary production interval.[111]

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[109] EPRI, *Enhanced Oil Recovery Scoping Study* (1999) (Available at: http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf). Attached as Exh.III-78.
[110] Hovorka, S., MIT Symposium on role of EOR in accelerative deployment of CCS, *EOR as sequestration--Geoscience perspective* (2010) (Available at: http://web.mit.edu/mitei/docs/reports/eor-css/hovorka.pdf). Attached as Exh.III-85.
[111] Southeast Carbon Sequestration Partnership (SECARB), *Gulf Coast Stacked Storage Project* (Available at: http://www.netl.doe.gov/publications/proceedings/07/rcsp/factsheets/19-SECARB_Gulf%20Coast%20Stacked%20Storage%20Project.pdf). Attached as Exh.III-79.

There are a number of advantages to EOR storage: 1) oil companies possess long exprience with managing, injecting and tracking injected CO_2, 2) depleted oil fields offer known reservoir capacities and injectivities and can--today--accept large volumes of CO_2 for tertiary oil production and subsequent storage, 3) EOR fields are equipped with the facilities to manage and inject CO_2, 4) oil fields are proven traps, known to hold oil and gas for millions of years, and 5) multiple injection and production wells offer the potential to manage the subsurface CO_2 plume.

Advanced Resources Inc. for the U.S. Department of Energy estimates that approximately 45 billion tons of CO_2 could *technically* be utilized and/or stored at an oil price of $85 per barrel, 20 billion metric tons *economically* utilized and stored using next generation EOR.[112] More recently, petroleum geologists and reservoir engineers have identified residual oil zones (ROZ)[113] in Texas and Wyoming and elsewhere in the naturally waterflooded zones below the main pay zone, as illustrated in Figure III-6 below.[114] Because they have been naturally waterflooded and the residual oil can no longer be mobilized with water, production of these accumulations requires CO_2. As there are currently inadequate CO_2 supplies to flood existing reservoirs and ROZs, substantial new volumes of anthropogenic CO_2 will be needed to produce oil from ROZs. This next-generation EOR, including some estimates of ROZ production, may produce as much as 135 billion barrels of oil in the Permian Basin of Texas, yet only 12% from utilization of existing CO_2 sources. Advanced Resources Inc for the U.S. Department of Energy also has estimated that next generation EOR combined with the limited estimates of ROZ production could produce a demand for approximately 20 billion tons of CO_2.[115] The National Coal Council (NCC) suggests, in addition to that estimated 20 billion metric tons of demand,

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[112] NETL, *Improving domestic energy security and lowering CO2 emissions with "next generation" CO2 enhanced oil recovery* (2011) (Available at http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf). Attached as Exh.III-77.

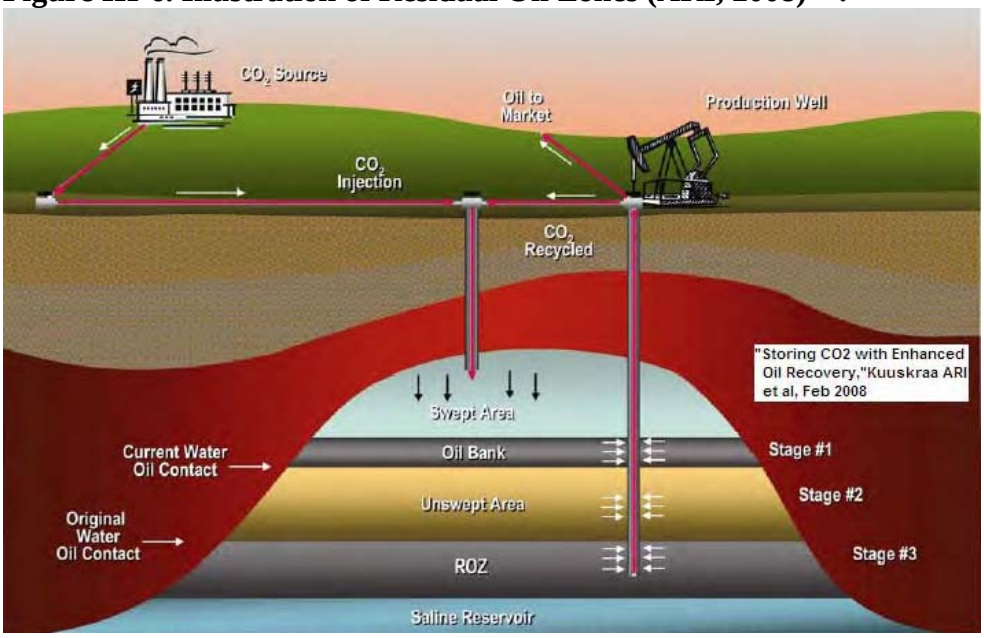
[113] "Residual oil zones" are at the new frontier in petroleum geology. They are recently discovered naturally waterflooded oil deposits that are below the main "pay" zone (oil-water contact) that can be produced with CO_2.

[114] See Permian Basin newsletter, available at: http://www.permianbasinccs.org/newsletter/V1N1.pdf; *see also* Presentation by Steve Melzer USGS Stanford Sequestration Workshop (May 10, 2011), *available at:* http://www.residualoilzons.com/resources/USCS-StanfordEOR-SequestrationWorkshop-Melzer5-10-11.pdf. Attached as Exh.III-80.

[115] NETL, *Improving domestic energy security and lowering CO2 emissions with "next generation" CO2 enhanced oil recovery* (2011) (Available at http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf). Attached as Exh.III-77.

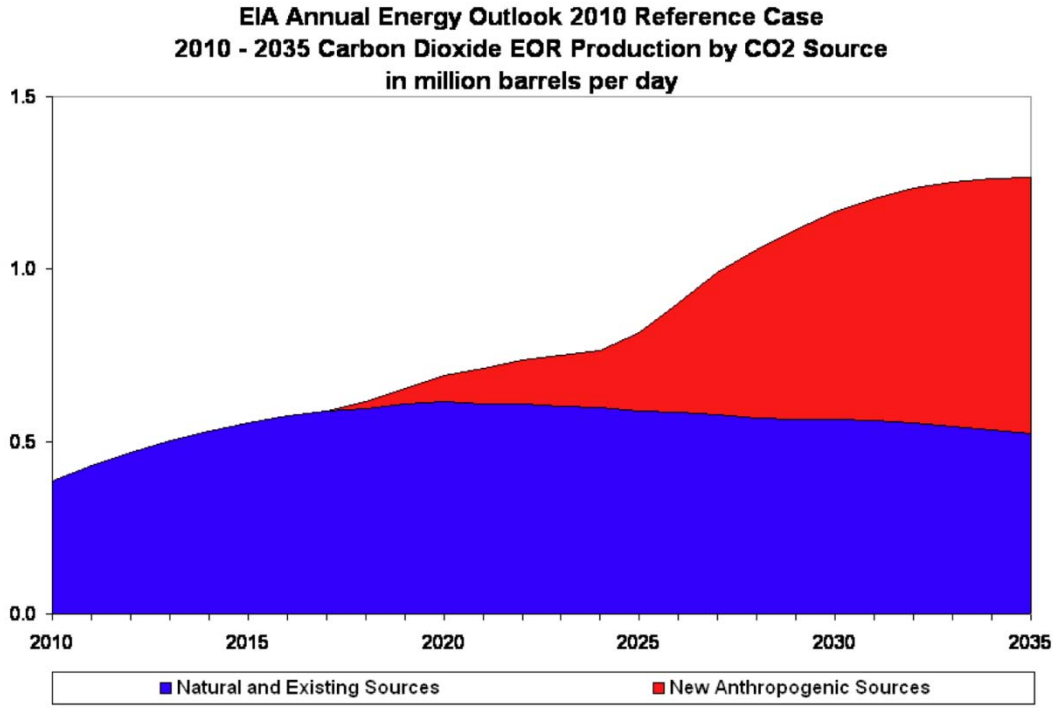
that next-generation EOR would utilize an additional 13 billion metric tons of CO_2 that could be sequestered in developing ROZ, for a total of 33 billion metric tons of CO_2 demand.[116] Approximately 2 billion of those tons of CO_2 are presently available from existing natural and anthropogenic sources, which leaves an additional demand and storage capacity for approximately 18 billion metric tons for next-generation EOR or 31 billion additional metric tons needed. An analysis by the U.S. Energy Information Administration (see Figure III-7, below) supports the conclusion that future EOR oil production in the lower 48 states will require substantial captured CO_2. This highlights the importance of new anthropogenic sources in meeting that demand and in the process of providing revenues from the captured CO_2 that is stored.[117] Similarly, Steve Melzer (2012)[118] notes that naturally mined sources of CO_2 and CO_2 from natural gas processing plants will be unable to meet the CO_2 demand for next generation EOR.

Figure III-6. Illustration of Residual Oil Zones (ARI, 2008)[119].



[116] National Coal Council, *Harnessing coal's carbon content to advance the economy, environment and national security*, at 4 (2012). Attached as Exh. III-88.
[117] Moreover, this market demand is creating incentives for industry to develop cheaper capture technologies, so that the price of anthopogenic CO_2will be more competitive with mined natural CO_2. See Crooks, "GE Launches New Carbon Capture Technology" *see supra* n. 90.
[118] Presentation by Steven Melzer, USGS Stanford Sequestration Workshop (May 10, 2011), *available at* http://www/residualoilzons.com/resources/USGS-StanfordEOR-SequestrationWorkshop-Melzer-5-10-11.pdf. Attached as Exh.III-86.
[119] Advanced Resources International, *Storing Oil with Enhanced Oil Recovery* (2008) (Available at http://www.adv-

Figure III-7: An EIA estimate illustrating that the increasing demand for CO_2 in EOR oil production will require new captured sources of CO_2[120].



(c) Current data demonstrates that ample CO_2 saline storage capacity exists in U.S. sedimentary basins today.

Exhibit III-115 (attached) includes a series of maps created by CATF using the National Energy Technology Labs NATCARB Viewer[121] that illustrate US geologic sequestration resources. Exhibit III-115a illustrates the widespread U.S. sedimentary basins; regions that contain layered sedimentary rocks such as sandstones that may be utilized for carbon storage, both onshore and offshore. Exhibit III-115b illustrates areas underlain by saline aquifers, formations that could accept CO_2 for deep disposal. In these areas, DOE's regional carbon sequestration partnerships (RCSPs) have identified saline rock formations that could accept large

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res.com/pdf/storing%20CO2%20with%20Enhanced%20Oil%20Recovery%20MAY%2008%20ARI%20Kuuskraa.Ferguson.VanLeeuwen.pdf). Attached as Exh.III-81.

[120] AEI Annual Energy Outlook 2010 Reference Case.

[121] The NETL NATCARB Viewer tool is available at: http://www.natcarbviewer.com/.

volumes of CO_2 that DOE estimates are on the order of 1.6-20 trillion metric tons.[122] Exhibit III-115c shows areas underlain by oil and gas reservoirs that would likely offer capacity for CO_2 EOR and possible stacked storage. DOE estimates approximately 124 billion metric tons of CO_2 could be stored in oil fields.[123] Exhibit III-115d highlights regions with coal supplies and existing or potential for coal-fired power plants. Exhibit III-115e is a composite showing the overlap of coal basins, sedimentary formations, saline reservoirs, oil reservoirs and coal plants (black dots). In this map, storage resources would appear to overlap substantially with coal resources. It is likely that future coal plants predominantly will be built in areas with coal resources and therefore coal plants will likely have access to geologic storage.

(i) The spatial availability of geologic saline storage sites overlaps distribution of coal resources: CO_2 storage sites will be near any new coal plants.

Exhibit III-115e shows the overlap between coal resources (yellow), geologic storage sites (blue and red) and the largest 500 coal power plants. This overlap is not a coincidence, but is expected because coal resources occur only in sedimentary basins where it is very likely that there also will be saline water-bearing formations at depth. If new coal plants are built where coal supplies are most plentiful, geologic carbon storage resources also will likely be readily available, underlying these plants, or nearby. Research by Battelle's Joint Global Change Research Institute (Dooley *et al.*, 2006) concluded that the largest U.S. sources (dominated by coal power plants) are within a reasonable range of a candidate storage site. The locus of new coal plants will likely be similar to the existing largest plants, because those plants are located in areas of, or with access to coal reserves. The report finds that: "[w]ithin the United States, the potential application of CCS systems to the 500 largest CO_2 point sources could potentially yield substantial CO_2 reductions, since fully 95 percent of these sources are within 50 miles of a candidate CO_2 reservoir."[124]

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[122] DOE, *The North American Carbon Storage Atlas*, Appendix C (2012) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf). Attached as Exh.III-71.
[123] *Id.*
[124] Dooley, J.J., *et al., Carbon dioxide capture and geologic storage: a core element of a global energy technology strategy to address climate change*, Battelle Joint Global Carbon Research Institute (April 2006). Attached as Exh.III-10.

Table III-2 summarizes and illustrates the vast capacity of saline and depleted oil-bearing geologic formations to store CO_2, and provides a detailed table of storage resources CO_2 by geologic basin, illustrating the availability of sequestration resources across the U.S.

Table III-2. Large regional stationary sources and Regional Carbon Storage Partnerships regional storage volume estimates.

Regional Carbon Sequestration Partnership	**Large Stationary Source CO_2 Emissions** (GT/YR)	**Saline Storage capacity (low-high)** (GT)	**EOR Storage Capacity** (GT)
Blue Sky (BSCSP)	0.02	220-3040	2
Midwest GS Consortium (MGSP)	0.26	10-160	1
Midwest Regional (MRCSP)	0.70	45-180	15
Plains (PCOR)	0.40	125	8
Southeast (SECARB)	1.03	910-12,250	30
Southwest (SWP)	0.29	220-3,010	60
West Coast (WESTCARB)	0.22	80-1,120	4
Non RCSP (New England states)	0.08	unk	0
TOTAL	**3.02**	**1,610-20,155**	**120**

Source: The North American Carbon Storage Atlas (2102)
Available at: http://www.nacsap.org.

(ii) Abundant Offshore Geologic Carbon Storage Capacity Is Available

Offshore U.S. carbon storage resources are infrequently discussed despite the fact that the geologic formations lying deep below U.S. offshore regions provide very large potential resources to sequester CO_2. DOE estimates that 500 billion to 7.5 trillion tons of CO_2 could be sequestered in all U.S. offshore formations.[125] Moreover, offshore Gulf Coast reservoirs have proven trapping capability having contained oil and gas resources for millions of years. Recent work done by the Gulf Coast Carbon Center (GCCS) at the University of Texas, Austin has

[125] DOE, *The North American Carbon Storage Atlas* (2012) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf). Attached as Exh.III-71.

mapped and estimated the magnitude of the large storage volumes in the Gulf of Mexico.[126] The work of GCCS has documented capacity for billions, if not trillions of tons of CO_2 in geologic formations below the Gulf of Mexico. There are promising targets for offshore storage for sources of CO_2 off the east coast as well. For example, offshore geologic storage is potentially available in the Northeast U.S. the U.S. Geological Survey (USGS) completed an offshore exploratory drilling program in 1979 off the coast of New Jersey, described in an U.S.G.S. Open File Report.[127] The report details the stratigraphy encountered during drilling that includes thick sandstones of Mississippian age capped by a thick mudstone. Furthermore, research is underway to characterize the Triassic basins off New York and New Jersey.[128] This resource could be important for New England where there are limited onshore geologic storage resources in a largely igneous and metamorphic bedrock terrain. In the Southeast U.S., studies are underway to assess the storage capacity in the South Georgia Rift Basin.[129] On the west coast, in California, some reports indicate the potential for storage resources as well. Research is ongoing to estimate the large-scale CO_2 storage capacity of the Wilmington Graben, which is offshore of Los Angeles.[130]

(4) <u>The Status of U.S. Geologic Storage Tests Provides Additional Support for the Viability of Sequestration Resources.</u>

The following projects illustrate the diversity, availability and injectivity of geologic sequestration resources across the U.S. The DOE coordinates the Regional Carbon Sequestration

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[126] Meckel, et al., *Offshore CCS in the Northern Gulf of Mexico and South Atlantic*, Poster, Regional Carbon Sequestration Partnership Meeting Pittsburgh (September 2011), attached as Exh. III-89.

[127] U.S.G.S., *Geological and operational summary*, Cost B-3 Will, Baltimore Canyon Through area, Mid Atlantic OCS, U.S.G.S. Open File Report 79-1159, Attached as Exh.III-90.

[128] *See* NETL, *Characterization of the Triassic Newark Basin of New York & New Jersey for Geologic Storage of Carbon Dioxide* (Available at http://www.netl.doe.gov/publications/factsheets/project/FE0002352.pdf). Attached as Exh.III-91.

[129] *See* NETL, *Geologic Characterization of the South Georgia Rift Basin for Source Proximal CO_2 Storage* (Available at http://www.netl.doe.gov/publications/factsheets/project/FE0001965.pdf). Attached as Exh.III-92.

[130] *See* NETL, *Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2* (Available at http://www.netl.doe.gov/publications/factsheets/project/FE0001922.pdf). Attached as Exh.III-93.

Partnership (RCSP) storage research projects.[131] Ten specific geologic storage research projects across the U.S. (as of 2010) are currently funded under the American Reinvestment and Recovery Act.[132]

a. SECARB Stacked Storage Test, Denbury Resources Cranfield Field, Mississippi

The cooperative work at Cranfield demonstrates the capacity for commercial volumes of CO_2 to be contained in stacked storage in a formation in the Gulf Coast region, and, moreover, has advanced monitoring, reporting and verification and accounting (MRV) methods that are an integral part of geologic storage technology and ensure secure commercial carbon storage in both saline reservoir and oilfield settings. [133] [134] [135] [136] A project of the Texas Bureau of Economic Geology Gulf Coast Carbon Center, Denbury Resources and others, the Cranfield Mississippi oilfield geologic carbon storage project began injection operations in 2009 and had injected 3.5 million metric new tons of CO_2 into the Tuscaloosa Formation as of March 2012 and approximately 5 million tons when CO_2 recycling is accounted for. The Tuscaloosa is an available widespread oil producing formation in the Gulf Coast region with multiple overlying confinement zones. Three years of cooperative SECARB work at Cranfield's stacked storage (having numerous layers capable if storing CO_2) site has aimed at evaluating methods for tracking injected CO_2 in a deep saline reservoir within an existing oilfield. One specific goal of the project is to evaluate protocols that demonstrate a 99 percent probability of 100 percent retention of the injected CO_2, and to test predictions of storage capacities in the field. During the course of the project, a variety of methods have been tested focusing on optimizing MRV methods for commercial use. Results are presently informing the development of MRV plans for CO_2 EOR projects planned in Texas. In addition, Texas BEG researcher, Katherine Romanak,

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[131] *See* NETL, http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp.html. Attached as Exh.III-94.
[132] *See* NETL http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/geologicsitechar.html. Attached as Exh.III-95.
[133] See: http://www.beg.utexas.edu/gccc/cranfield.php. Attached as Exh. III-96.
[134] http://sequestration.org/mgscprojects/deepsalinestorage.html. Attached as Exh. III-97.
[135] SECARB, "early test" at Cranfield MVA update. Attached as Exh. III-98.
[136] SECARB Gulf Coast Stacked Storage project fact sheet. Attached as Exh. III-79.

has developed a new approach to soil gas measurements at Cranfield that can identify sources of leaked CO_2 independent of the methods used to track CO_2 volumes over time. The method has been successfully tested at the Weyburn Field in Saskatchewan.[137]

b. SECARB Frio Formation Brine Pilot Injection Test, Texas.

The Frio brine pilot was the first saline injection test in the U.S. and was conducted by the Texas Bureau of Economic Geology with the support of NETL and Texas American Resources. The injection site was located in a historic oil field in Texas, selected in 2003 after characterization of 21 saline storage formations in the U.S.[138] The Frio Formation sandstones are thick and regionally extensive, potentially ideal for CO_2 injection and long-term storage. It has been estimated that across the Gulf Coast the Frio Formation has a capacity to store between 208 and 358 billion tons of CO_2.[139] The Frio pilot test consisted of two phases. In phase 1, in 2004, 1,600 metric tons were injected to a depth of 1,500 meters, accompanied by monitoring and modeling. A second phase test injection of 300 metric tons at a depth of 1,570 meters was completed in 2006. The testing confirmed the injectivity of the formations and demonstrated the effectiveness of using geochemical and geophysical techniques to document the evolution of the CO_2 plume.[140]

c. ADM Saline Test, Decatur IL

A successful 7,000 foot deep saline injection test is underway in Decatur IL, including a comprehensive monitoring program. It is a cooperative project of Archer Daniels Midland (ADM), the Midwest Geological Sequestration Consortium, and Schlumberger with $4.4 million

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[137] Romanak, *Analysis of Gas Chemistry at the Kerr Site*, IPAC Publication (2012). Attached as Exh. III-46.

[138] Hovorka et al., *Monitoring CO2 storage in brine formations: lessons learned from the Frio field test one year post-injection* (2006) (Available at http://www.gwpc.org/e-library/documents/co2/UIC%2006%20Monitoring%20CO2%20storage%20in%20brine%20formations-%20lessons%20learned%20from%20the%20Frio%20field%20test%20one%20year%20post%20injection.pdf). Attached as Exh. III-99.

[139] Hovorka, S., *Evaluation of brine-bearing sands of the Frio Formation, upper Texas Gulf Coast, for geological sequestration of CO2* (2001) (Available at http://www.beg.utexas.edu/environqlty/pdfs/hovorka-netl01.pdf). Attached as Exh. III-100.

[140] Hovorka, S. et al., Powerpoint for Gulf Coast Carbon Center, *GCCC Field monitoring projects* (2008). Attached as Exh. III-101.

of DOE support.[141] During the 3-year injection program, 1.1 million tons of CO_2 will be captured at ADM's ethanol plant using Alstom's amine capture process and will be injected into the Cambrian Mt. Simon Formation. A second well is planned which will bring the total to approximately 1 million tons per year. Monitoring tools utilized at the site include four shallow groundwater wells and soil gas measurements, 3-D seismic profiling, a dedicated monitoring well with embedded geophones for walk-away vertical seismic profiling (VSP) and a dedicated in-zone monitoring well. The success of this project underscores the availability of commercial scale saline geologic sequestration in the Mt. Simon Formation under the Midwest United States, an area rich in coal and the present and likely future locus of coal-based electric power generation

d. MRCSP Duke Energy East Bend Generating Station, Cincinnati Arch Kentucky Geologic Injection Test.

During the first CO_2 injection test of the Mt. Simon Formation that underlies much of the Midwest U.S., 910 metric tons of CO_2 were injected from September 20-25, 2009 at a depth of about 3,500 feet near the Duke generating station into a 300 foot section of the Mt. Simon sandstone. Rates of 1,200 metric tons per day were sustained during several hours of the test indicating good permeability and injectivity of the formation. [142]

e. MRCSP First Energy RE Burger Plant Injection Test, Shadyside, Appalachian Basin, OH.

Test injections were made at the First Energy RE Burger test site between 5,900 and 8,300 feet depth into the Oriskany Sandstone, the Salina Formation and the Clinton Formation. A very small amount of CO_2 was injected as the formations in this area were found to be tight.

f. MRCSP/ Core Energy EOR Injection Test, Michigan.

The Midwest Regional Carbon Sequestration Partnership, in cooperation with Core Energy, are utilizing CO_2 from a DOE gas separation plant from the Antrium gas field, for EOR and a saline test. The CO_2, otherwise being vented to the atmosphere, is being sent from the gas

[141] *See* http://sequestration.mit.edu/tools/projects/decatur.html. Attached as Exh. III-102.
[142] *See* http://www.battelle.org/spotlight/11-15-11_mrcsp.aspx. Attached as Exh. III-103.

plant to the oil field via an 8 mile pipeline. The CO_2 injected is being used for both EOR in the Niagran reef system, as well as for a deep saline test of several formations, including the St. Peter sandstone, at a depths ranging from 3,500 to 7,500 feet and below the oil and gas producing horizon.[143] A successful pilot test of deep geologic injection, accompanied by monitoring, of 60,000 tons of CO_2 from February to March 2008 demonstrated "industrial-scale CO_2 sequestration potential" in the Bass Islands Dolomite at 3,500 feet. The next series of saline test injections have yet to commence due to a delay in permitting. This project demonstrates storage capacity in depleted petroleum -bearing and saline formations in the upper U.S. Midwest including northern Michigan.[144]

g. Wellington Kansas CO_2 Injection Test.

In 2009, Kansas State University, Lawrence Berkeley National Laboratory, Sandia Technology and BEREXCO Inc., initiated an injection test below a depleted oil field in Wellington Kansas that will be completed mid-2013.[145] Approximately 40,000 tons of industrial CO_2 will be captured and injected at a depth of about 5,000 feet into the saline Arbuckle sandstone and an additional 30,000 tons will be injected into a shallower formation of Mississippian age. Researchers will use state-of -the art monitoring techniques to track the CO_2 plume and its seismic properties in the subsurface and to assess the viability of saline injections in the southwest region.

h. Southwest Partnership (SWP) Projects: Aneth, San Juan, and Wasatch Plateau Gordon Creek Field Injection Tests.

The Wasatch Plateau Gordon Creek Field Injection Test is a project of the Southwest Partnership with the New Mexico Institute of Mining, Schlumberger and Los Alamos National Laboratory. The objective of this project is multi-year commercial scale injection while testing risk

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[143] *See* http://sequestration.mit.edu/tools/projects/otsego.html. Attached as Exh. III-104.
[144] *See* MRCSP Phase II Final Report, April 2011: http://216.109.210.162/userdata/phase_II_reports/phase_ii_final_report_MRCSP.pdf. Attached as Exh. III-105.
[145] Watney, W.L. *et al*., *Modeling CO2 sequestration in saline aquifer and depleted oil reservoir to evaluate regional co2 sequestration potential of Ozark plateau aquifer system, south-central Kansas* (2011) (Available at: http://www.netl.doe.gov/publications/proceedings/11/carbon_storage/thursday/1_Watney%20--%20FE0002056%20overview%20Final%2011-16-11.pdf). Attached as Exh. III-106.

assessment and MVA efficacy, water management, and to provide a blueprint for commercial scale storage in the SWP region. Storage capacities in the SWP region states in the SWP region are considerable and are listed in Table III-3. SWP's broad strategy is to develop CO_2 storage reservoirs along pipeline corridors. [146] The SWP began its work in Phase 1 with characterization (2003-2005) followed by validation (2005-2009). The SWP Aneth EOR and sequestration project began in August 2007 and 292,300 tons were injected accompanied by successful seismic imaging tracer monitoring and EOR with net CO_2 storage. In the SWP San Juan enhanced coal bed methane project 18,400 tons of CO_2 were successfully injected accompanied by successful vertical seismic profiling, tiltmeter deployment, and tracer testing. At Gordon Creek, SWP is preparing for the Phase 3, a 1-million ton per year (for 3-4 years) multiple-zone saline injection test into the Jurassic Entrada and Navajo sandstones beginning in 2013.[147] Although the CO_2 to be utilized in the project is naturally mined, the Gordon Creek test will demonstrate the viability of containing large volumes of CO_2 in these widespread southwest U.S. formations. [148] A CO_2-injection modeling effort will commence in 2012 followed by injections in 2013.

[146] SWP phase 3 deployment project overview and summary, available at http://www.netl.doe.gov/publications/proceedings/10/rcsp/presentations/Wed%20am/Dawn%20Deel/McPherson.%20Grigg.swp.%20phase3.annual.pitt.rcsp.oct2010.shorte.pdf. Attached as Exh. III-107.

[147] *See* http://sequestration.mit.edu/tools/projects/wasatch_plateau.html. Attached as Exh. III-108.

[148] *See* http://www.carboncapturejournal.com/displaynews.php?NewsID=826. Attached as Exh. III-109.

Table III-3. Estimated CO_2 Storage Capacities by State in the SWP region.

(source: SWP phase 3 deployment project overview and summary. *Available at* http://www.netl.doe.gov/publications/proceeding/10/resp/presentations/Wed%20am/Dawn%20Deel/McPherson%20Grigg.swp.%20phase3.annual.pitt.resp.oct2010.shorte.pdf.)

Saline Formation CO_2 Storage Resource by State (million metric tons)		
State	Low CO_2 Storage Resource	High CO_2 Storage Resource
Arizona	199	752
Colorado	18,828	75,313
Nebraska	87	348
New Mexico	33,054	132,215
Texas	11,700	46,800
Utah	24,934	99,305
Wyoming	4,909	19,636

i. Exxon LaBarge Project, Wyoming

Exxon's LaBarge Shute Creek gas separation and processing plant is the world's largest CO_2 capture operation.[149] The anthropogenic CO_2 captured is transported via pipeline for CO_2 EOR in the SWP region. Capture volumes began with 4 MMT/y in 2008 and the project was expanded in 2010 to 6 MMT/y.

(5) **Hydraulic Fracturing Operations Used in Unconventional Oil and Gas Production Won't Significantly Limit Geologic Storage Availability**.

A recent paper by Princeton researchers has questioned the compatibility of hyrdraulic fracturing (fracking) activity undertaken for oil and gas production, with geologic carbon sequestration activity.[150] In response, we note that overwhelming evidence suggests geologic storage can, indeed, coexist safely with other subsurface resource utilization activities, including oil and gas extraction and fracking. The Princeton study mkes the implicit assumption that the productive shale gas formation in any given area would serve a duplicate function as the seal for the saline formation below. But sedimentary geology is complex, and does not consist of just two simple layers, the CO_2 reservoir and the cap rock/shale gas target. Instead, sedimentary basins

[149] *See* http://sequestration.mit.edu/tools/projects/la_barge.html. Attached as Exh. III-110.
[150] Elliot T.R. and Celia M.A., *Potential restrictions for CO2 sequestration sites due to shale and tight gas productioni*, 46 Environmental Science and Technology, 4223-4227 (2012). Attached as Exh. III-39.

typically consist of thousands of feet of bedrock, with multiple layers of shale, sandstones, limestones (that may also be "tight" or largely impermeable) and other sedimentary rocks. And, because CO_2 must be injected in a fluid-like "supercritical" state (rather than as a gas), sequestration must take place at depths of at least one half mile. In the Illinois basin, for example, near the heart of the coal power industry, CO_2 injected into the available formations would have to travel upwards through multiple impermeable formations comprising nearly 7,000 feet of rock to approach the first freshwater aquifer or the surface.

Even if incompatibility with fracking operations exists in some production areas, the DOE in 2012 estimated that U.S. geologic formations can provide 1.6 to 20 trillion metric tons of storage space for CO_2 – by DOE's most conservative estimate roughly 500 times or more the current U.S. power sector's emissions 2.4 billion tons of CO_2 annually.[151] And that analysis doesn't take into account the DOE estimate of an additional 124 billion tons of CO_2 storage capacity in depleted petroleum-bearing formations, and other saline formations stacked below, that have contained oil and natural gas for millions of years. Finally, the Safe Drinking Water Act mandates that geologic storage operators must complete a comprehensive study of the geology and risks before CO_2 injection and storage in saline aquifers can be initiated.

(6) Seismic Risk Won't Threaten the Viability of Long-Term Geologic Carbon Storage

Two Stanford geophysicists have recently raised concerns, in the Proceedings of the National Academy of Science (PNAS) *Perspectives*, about seismic risks due to CO_2 injection and sequestration practices.[152] While their opinion piece rightly raises the importance of rigorous site selection and site characterization for commercial scale storage, it falls far too short in its

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[151] DOE, *The North American Carbon Storage Atlas*, Appendix C (2012) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf). Attached as Exh.III-71. *See also* Press Release, "Energy Department Announces New Mapping Initiative to Advance North American Carbon Storage Efforts" (May 1, 2012) (Available at http://energy.gov/articles/energy-department-announces-new-mapping-initiative-advance-north-american-carbon-storage). Attached as Exh.III-82.

[152] Zoback, M. and Gorelick, S., *Earthquake triggering and large-scale geologic storage of carbon dioxide*, Proceedings of National Academy of Science, Perspectives; (Early Edition, June 19, 2012) (Available at http://www.pnas.org/content/early/2012/06/13/1202473109.abstract). Attached as Exh. III-111.

analysis of the overall feasibility of storing commercial volumes of CO_2. By analogy with recently experienced earthquakes resulting from brine injections, the authors attempt to cast doubt on the feasibility of large-scale geologic storage of carbon dioxide captured from industrial sources by pointing to the role of CO_2 pressure buildup in the hosting formations in their potential to induce earthquakes and resulting fractures and faults. Their concern is not about the impacts of tremors nor large scale earthquakes that would let CO_2 rush out, but instead about the possibility that the induced seismicity could be accompanied by small-scale fracturing that could migrate upwards and compromise integrity of an overlying geologic seal.

But there have been no earthquakes reported from saline CO_2 injections to date, according to the June 15, 2012 NSA report, *Induced Seismicity Potential for Energy Technologies*).[153] And, what the article does not say, is that for a brittle fault or fracture to reach the surface would require crossing thousands of feet of rock and shale layers – which, in the process may accommodate the upwardly propagating stress like a plastic substance bending like taffy–rather than fracturing. The authors also do not address the rate at which any CO_2 affected by such small scale fracturing might migrate over time, and whether those volumes would be significant in the near term period in which CO_2 sequestration offers the promise of a bridge to more low-carbon options, while mitigating the current impacts of CO_2 on global climate change.

The authors also describe a scenario of limited storage capacity for power plant CO_2 generated in the Midwest's Illinois Basin–the U.S. locus of coal power generation. They overlook numerous storage strategies that would complement local and regional storage in the Midwest, however. For example, they rely on the unrepresentative example of American Electric Power's Mountaineer pilot CCS project in West Virginia, combined with computer modeling of the Illinois basin done in 2009 by Lawrence Berkeley National Laboratory undertaken for a purpose other than to predict seismicity. But, the poor injectivity in the Mt. Simon formation beneath the Mountaineer project simply suggests that the Mt. Simon at this location is undesirable as a geologic storage resource. It is not representative of the geology of

[153] National Academy of Sciences, *Induced Seismicity Potential in Energy Technologies,* Proceedings of the National Academy of Science (June 15, 2012) (link to document at http://www.nap.edu/catalog.php?record_id=13355). Attached as Exh. III-112.

Mt. Simon Formation across the entire Illinois basin.[154] Additionally, a complete understanding of three-dimensional subsurface geology is critical. In the Illinois Basin, there are other formations that have the potential to simultaneously store CO_2. The University of Texas Bureau of Economic Geology Gulf Coast Carbon Center has been investigating stacked storage in combination with EOR in brine formations below producing zones in Mississippi. At their Cranfield, Mississippi test site, they have injected over 3 million metric tons of CO_2 into the Tuscaloosa Formation.[155]

Also, CO_2 can and will be pipelined to the Gulf Coast and Texas' Permian Basin for enhanced oil recovery. Plans are underway for an extension CO_2 pipeline that will extend Denbury Resources' existing "Green Pipeline" up into southern Illinois to tap into anthropogenic sources of CO_2.[156] A 2011 NETL study suggests next-generation EOR in depleted U.S. oilfields can accommodate an additional 20 billion tons of CO_2.[157] A National Coal Council study suggests that including ROZ, this number could go to 33 billion metric tons of CO_2 demand[158]. Pipelines also could carry CO_2 to other formations in the offshore Gulf, Atlantic and Pacific coasts where there are an estimated 500 billion to 7.5 trillion tons of storage capacity, according to DOE. [159] CO_2 pipeline build-out has been studied by Battelle for several international climate mitigation scenarios. [160] ARI estimates that three 800-mile pipelines could accommodate the CO_2 from Midwest power plants for 30 years.[161] Finally, brine water production from the saline

[154] Braine, B., Conference Presentation, *Climate Change and Technology, Opportunities and Risks*, at16 (Available at http://www.esrl.noaa.gov/gmd/co2conference/pdfs/braine.pdf). Attached as Exh.III-113.
[155] SECARB, Exh. III-79.
[156] *See* http://www.denbury.com/Corporate-Responsibility/Pipeline-Projects/midwest-pipeline-prospect/default.aspx.
[157] NETL 2011, Exh III-87.
[158] National Coal Council, Exh. III-88.
[159] NACSA 2012, Exh III-71. This study suggests that pipeline buildout is likely to occur at a reasonable pace, sufficient to handle demand for piped CO_2.
[160] Dooley 2009, Exh III-37.
[161] Kuuskaraa 2010, Exh III-38.

formation, and reinjection into other formations can relieve formation pressure that could potentially lead to rock failure.

Finally, CO_2 injection technology is hardly new. As noted above, approximately 1 billion tons of CO_2 have been safely injected (and stored) in the process of enhanced oil recovery in the U.S. since the late 1970s with no reported seismic incidents according to the NAS report.

IV. EPA's Proposed Exemption from the Standard for "Potential Transitional Sources" Is Unnecessary, and Overbroad/Unjustified.

While we strongly support the Agency moving forward with this first-ever regulation of stationary source greenhouse gas emissions, we have serious concerns about EPA's proposed treatment of what it calls "transitional sources." Specifically, EPA has proposed a complete exemption from the statute's requirement that all new sources constructed after the publication date for the proposed rule must meet the NSPS, for what it refers to as "a distinct set of sources" that otherwise meet the applicability requirements but that have "complete" preconstruction PSD permits as of the proposal date,[162] and that commence construction prior to April 13, 2013. 77 Fed. Reg. at 22,423/2, 22,436 (proposed 40 C.F.R.§60.5510(b)(3)). The agency identifies a list of 15 "potential transitional sources," all of which are coal plants, and only 6 of which have planned any CO_2 control. *Id.* at 22,422,[163] *see also* RIA at 2A-1 (listing identified 'potential transitional sources' in Appendix 2-A).

The nine remaining power plants identified by EPA as "potential transitional sources" that do not plan to use CCS to control their CO_2 emissions simply do not merit the special treatment EPA proposes, either on policy grounds or as a legal matter. Building a coal-fired power plant under current economic conditions is a risky and ill-advised investment. As EPA recognizes, dozens of similarly ill-conceived projects have already been canceled. 77 Fed. Reg. at 22,422, n.66. Building even a single coal-fired power plant without CCS also is particularly damaging to the climate--each new uncontrolled coal plant emits millions of tons of CO_2 per year. Not only are new power plant facilities likely to remain in service for 40 years or more, so that the lifetime CO_2 emissions from one moderately sized facility will approach a quarter billion tons, but CO_2 remains in the atmosphere for a long time, causing climate harms for on the order of a century. In no way can the construction of even a single uncontrolled coal plant be

[162] Or, where the proposed source is participating in a U.S. Department of Energy funding program for CCS, where the source has an expired PSD permit that is in process of being extended. 77 Fed. Reg. at 22,436 (proposed 40 C.F.R.§60.5510(b)(3).

[163] The list, at the time it was published, only includes coal-fired sources, as EPA notes that any new gas-fired plant "will be able to meet the requirements of the proposed new source standards …." 77 Fed. Reg. at 22,422 n. 67. EPA also states, *id at 22,422/3*: "Of the[] 15 identified potential transitional sources, six have indicated that they plan to install CCS (and in most if not all cases have been issued or awarded a DOE CCS loan guarantee or grant).

considered insignificant. Nor will EPA's adoption of the proposed exemption for these sources advance emerging CO_2 control technologies like CCS in any way.

Public information (which EPA has not included in the record underlying the rule or relied on as justification for the assertions the agency makes about developers' sunk costs in these projects) demonstrates that the 9 "potential transitional sources" that are not able to meet the NSPS for new sources are also highly unlikely to *ever* complete construction (whether or not they can manage to convince state authorities that they have "commenced" construction by April 2013). Specifically:

- Limestone 3 (Texas) received its PSD permit in December 2009, but has not identified any plans to proceed with the project.

- White Stallion (Texas) has not yet received a permit that U.S. EPA has said meets CAA PSD requirements.

- The Holcomb 2 (aka Sunflower) project does not qualify as a "potential transitional source" for numerous reasons. EPA has repeatedly advised the Kansas Department of Health and Environment in writing that the PSD permit for Holcomb 2 does not comply with the Clean Air Act because it does not include required emission limits to ensure that the plant will not exceed the one-hour NAAQS for NO_2 and SO_2.

- While the expansion of the James De Young coal-fired power plant in Holland, Michigan apparently is moving forward its permit is currently the subject of an appeal, and questions about the need for the plant undermine its financial viability;

- Wolverine faces similar challenges.

- Georgia's Plant Washington does not qualify under EPA's definition of a "transitional source" -- as of April 13, 2012, it had not obtained the required complete, final, and legally effective construction and operation air permit.

- The Bonanza plant proposal in Utah has been dormant for years, and does not hold a final complete PSD permit, so it should not appear on a list of "potential transitional sources."

- Two Elk is a proposed pulverized coal plant designed in the early 1990s, that originally applied for an air permit in 1996, began some construction, and has been apparently unable to find financing to complete the facility. The status of the air permit has been in dispute, and the developers have agreed that if construction lapses

again, a new, up-to-date air permit would be required (and in that case, EPA's first transitional source criterion would not apply).

And the "potential transitional source" projects that *do* propose (or did propose) to rely on CCS technology in fact *do not need* the exemption – given the 30 year averaging period EPA has proposed, these sources can and will meet EPA's proposed NSPS. Specifically, Summit's project is an integrated gasification combined cycle (IGCC) plant that plans to emit less CO_2 than a natural gas plant. The company's president, Eric Redman, stated in May of this year that "CO_2 emissions would amount to about 200 pounds per MWh, making the Texas plant far more climate-friendly than even the best combined-cycle natural-gas plants, which emit about 850 to 1,000 pounds per MWh."[164] The Tenaska (Texas Trailblazer) project's developer has publicly stated that "Trailblazer is designed to perform much better than the proposed standard."[165] The Tenaska Taylorville (Illinois) project has recently put its plans for a coal gasification plant including CCS on hold and is discussing constructing a natural gas facility instead, which also would meet the proposed standard. Similarly, the Good Spring plant's developers recently announced plans to construct a natural gas combined cycle facility which would meet the NSPS. The Power County (Idaho) plant's permit includes an enforceable CO_2 emission limit that would require the plant to achieve a 58 percent reduction in its CO_2 emissions – which is near the level needed to meet EPA's proposed standard immediately on commencement of operations. And the Cash Creek plant in Kentucky received an air permit in 2006 but has not moved forward to date. Finally, the Coletto Creek plant's developers have expressed willingness, if their plant is moves forward, to incorporate CCS technology in order to meet the proposed standard, although they are on the EPA list as a potential "transitional source" not intending to do so.

EPA puts forward several theories under which it hopes to justify its transitional source exemption, but all of which are unavailing. Essentially these arguments are, at their core, based on the sunk costs and extent of planning that the developers of these proposed sources have

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[164] Summit Power, Latest News, *at* http://www.summitpower.com/in-the-news/can-environmentalists-learn-to-love-a-texas-coal-plant/, *citing Can Environmentalists Learn To Love a Texas Coal Plant?*, Yale Environment 360 (May 31, 2012). Attached as Exh.IV-1.

[165] Bill Dawson, *Texas and carbon capture: A status report on power plants, policy and research*, May 15, 2012, at http://texasclimatenews.org/wp/?p=4972. Attached as Exh.IV-2.

undertaken to date towards development of their projects.[166] 77 Fed. Reg. at 22,424/2-3. Specifically, EPA asserts:

- that the extent of planning and investment already undertaken justifies the exemption alone, and on equitable grounds;
- that the Agency cannot propose a separate standard for these sources (even the sources proposing to implement CCS technology) because it doesn't have sufficient information to determine BSER for them;
- that because only a small number of sources will be able to satisfy the transitional source criteria, the environmental benefit of requiring them to meet the standard would essentially be *de minimis*;
- that there is precedent in previous NSPS rulemakings for EPA's decision "not to cover all sources within the source category; and finally,
- that these sources will eventually be subject to the section 111(d) performance standards for existing sources that the agency recognizes it must issue following the issuance of the new source standards.

None of these attempted rationales is persuasive on its face, or sufficient as a legal matter to support the broad exemption EPA has proposed, on the record before the agency.

Nor is EPA's treatment of transitional sources analogous to the creation of a lawful subcategory of the listed industry and a subsequent decision not to regulate based on the *National Lime* factors. EPA *might* have been able to justify the creation of a limited subcategory of already-permitted sources that intend to deploy CCS technology for CO_2 control, on the basis that as they already will be achieving the standard, an additional permit requirement does not increase environmental benefit or further the statutory purpose of advancing emerging technologies. Or, the agency *might* have proposed to offer these sources some relief under the waiver provisions of section 111(j) for innovative control technologies. But, that is not what the agency has done here. Instead the agency's exemption sweeps in sources that have no intention deploying any system for CO_2 control.

[166] EPA states: subjecting these sources to the proposed standard "could upset carefully crafted financial plans, causing delay or even cancellation of the project[s]." 77 Fed. Reg. at 22,425.

EPA asserts that it can exempt transitional sources from the proposed NSPS because the Agency is "not require[d to] … propose such standards for *all* new sources or for *any* new source." 77 Fed. Reg. 22,425/3. But EPA misreads the language of CAA sections 111(b)(1)(B) and 111(a)(2). Specifically, Section 111(b)(1)(B) states in relevant part that:

> Within one year after the inclusion of a category of stationary sources in a list under subparagraph (A), the Administrator shall publish proposed regulations, establishing Federal standards of performance for new sources within such category.

42 U.S.C. §7411(b)(1)(B). And section 111(a)(2) defines "new source" as including:

> … any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

Id. §7411(a)(2). Moreover, since at least 1970, it has been clear that new source standards developed for a listed industry are intended to apply to all sources on which construction is commenced after the date the proposal is issued. *See, e.g., U.S. v. City of Painesville,* 644 F.2d 1186, 1189-1190 (6th Cir. 1981)(noting that "Congress provided that even the publication of proposed regulations establishes the cut-off date for identifying new sources of a particular pollutant"). EPA's decision to allow a broad array of coal plant sources, some of which are simply "dead men walking," a full *additional year* to commence construction, in order to avoid the standards, clearly runs afoul of this requirement.

EPA *is* authorized to create subcategories within a listed source category, and determine that performance standards for a particular subcategory are not justified on the record before the Agency in a given review period, based on the *National Lime* factors discussed *supra* section I. Clean Air Act section 111(b)(2) authorizes EPA to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [performance] standards." 42 USC §7411(b)(2). It is not in dispute that during the course of fulfilling its mandatory duty to determine whether or not standards are "appropriate" for a listed industry, EPA may make a record-based determination that it cannot establish standards for a particular pollutant or subcategory of sources, because: (1) the amount of emissions of a given pollutant from that source category or subcategory is too small, or that (2) there are no demonstrated control

measures for the pollutant or the subcategory. *See National Lime*, 627 F.2d at 426 n. 27 (discussing these factors).

But, EPA has not proposed transitional sources as an industry subcategory,[167] and then justified a decision not to regulate that subcategory. Nor can it, as the agency has defined and identified this collection of sources. They simply do not represent a subcategory based on "class, type, or size."[168]

While EPA purports to find "precedents in prior NSPS rulemakings," 77 Fed. Reg. at 22,426, a look behind many of the citations the agency provides shows they offer no support for the agency's treatment of transition sources. Each of these is an example of the Agency describing and creating a subcategory of a listed industry, on the basis of "class, type, or size," and then determining not to propose, or in some instances, to finalize emissions standards for such subcategory, consistent with the *National Lime* analysis.[169]

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[167] Although EPA seems confused about what it actually is proposing, *see e.g.,* 77 Fed. Reg. at 22,423/3 (describing why the agency has not proposed a separate standard for transitional sources – as it would do for an industry subcategory), the language of the proposed rule clearly describes EPA's treatment of transitional sources as an "exemption." See *id.* at 22,436 (proposed 40 C.F.R § 60.5510(b)).

[168] As discussed further below, EPA could, in its final rule, identify a more limited transitional source subcategory based on class – namely those facilities designed to employ CCS and that already have received permits to do so (or indeed to use some other potential innovative CO_2 control technology), and could propose a section 111(j) waiver of the NSPS as applied to those sources.

[169] *See, e.g., National Lime Ass'n v. EPA*, 627 F.2d 416, 426 & n. 28 (DC Cir. 1980)(noting EPA's stated rationale for not proposing standards for the vertical kiln, rotary hearth kiln, and fluidized bed kiln as that they were not in widespread use at the time); 74 FR 25,304 (May 27, 2009)(determining to propose standards for thermal dryers, pneumatic coal-cleaning equipment, petroleum coke, and coal refuse after initially choosing not to, because each item had originally failed to meet either the amount of emissions or availability of technology prongs of the *National Lime* analysis; determining as well that an emissions standard for open storage piles – which are significant sources of potential emissions – would be infeasible); 71 FR 38,482 (July 6, 2006)(creating a new subcategory for turbines with smaller than 10 MMBtu/hr heat input and exemptions for emergency units and combustion turbine test cells); 40 C.F.R. §60.310(c)(EPA creating an exemption for any owner or operator of a metal furniture surface coating operation that uses less than 3,842 liters of coating (as applied) per year);
49 FR 2,636 (January 20, 1984)(EPA determining not to propose standards for "process emission sources" at natural gas processing plants because they failed to meet the availability of technology prong of the *National Lime* analysis).

Exemptions from clear statutory mandates, such as EPA's proposed treatment of transitional sources, can *only* be justified on grounds available in limited, record-based circumstances, and categorical exemptions like the one EPA proposes here are highly disfavored. *See, e.g., Alabama Power v. Costle*, 636 F.2d 323, 358 (D.C. Cir. 1979) (describing the limited availability of these doctrines). While EPA claims that the benefit from regulating all of the listed "potential transitional sources" would be limited, 77 Fed. Reg. at 22,427/2, the Agency bears a "heavy burden" to demonstrate that regulation would achieve only *de minimis* benefits. *C.f. Alabama Power*, 636 F.2d at 358-359 (noting that government officials are not permitted to "seize on a remedy made available for extreme illness and promote it into the daily bread of convenience").

EPA has not provided any record evidence that exempting all transitional sources from the new source standards would cause minimal harm or achieve minimal environmental benefits.[170] Nor has EPA made any effort to show that applying the statute as written, and requiring review and permitting based on the new source performance standard as proposed, would impose an impossible administrative burden on the part of any permit-issuing authority. The Agency simply can't make any record-based showing under these doctrines in support of the broad exemption it proposes. Instead, it attempts to shore up its proposed exemption only on cost grounds, which it may not do. EPA may not justify an exemption from clear statutory requirements "based on the agency's perceptions of costs and benefits" alone.[171] *Alabama Power*, 636 F.2d at 357; *see also Public Citizen v. FTC,* 869 F.2d at 1556 (same).

Finally, EPA's assertion that it is acceptable to exempt these sources from the *new* source performance standards because they will later on become subject to the required *existing source*

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[170] Here, the sources EPA proposes to exempt from the proposed rule will emit *tens of millions of tons of* CO_2 each year if built. Clearly allowing these sources to avoid any requirement to reduce their CO_2 emissions does not result in *de minimis* impacts.

[171] Nor are increased costs associated with meeting the new standard evidence of any absurd result from applying the statute as written – Congress intended and understood that compliance with new source standards after the date of publication would be costly, but imposed those costs understanding that "the short-term costs of 'maximum feasible control' are ultimately less expensive than the long-term costs of increasing air pollution." *U.S. v. Painesville,* 644 F.2d at 1191 (quoting S. Rep. No. 1196, 91st Cong. 2d Sess. 16 (1970).

standards, ignores not only the language of the statute but its purpose. The plain language demonstrates that Congress intended all new sources in a listed industry to meet performance standards from and after their publication. In part, that is because it is simply less expensive to plan for and install pollution control prior to constructing a new source than it is to add on pollution control years later. For these reasons, EPA must decline to finalize the complete transitional source exemption it has proposed.

VI. The Record does not support reliance on substitution of biogenic fuels as a compliance option, nor is EPA's decision to entirely exempt baseload and intermediate load biomass plants supported.

It is EPA's responsibility to "set forth the reasons for its actions" as "the fundamental requirement of nonarbitrary administrative decisionmaking." *Northeast Md. Waste Disposal Auth. v. EPA*, 358 F.3d 936, 949 (D.C. Cir. 2004), *citing Motor Vehicle Mfrs. Assn. of U.S., Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 48-50 (1983). The Clean Air Act specifically requires proposed and promulgated rules to set forth a "statement of basis and purpose" that summarizes "the major legal interpretations and policy considerations underlying the proposed rule." 42 U.S.C. §§7607(d)(3)(C), (d)(6)(A)(i). EPA has provided no record to support the use of biogenic material as a compliance option. Because no evidence in the record provides justification for exempting the CO_2 derived from co-firing biogenic fuel from counting towards compliance with the proposed performance standards, all CO_2 emissions from an EGU that has a baseload rating of 250 MMBtu/hr (73 MW) of a fossil fuel, including CO_2 resulting from the co-firing with biogenic fuels, must be included to determine compliance.

EPA states that it did not analyze what it calls the "unique treatment of CO_2 emissions from biologically-based material, otherwise called biogenic CO_2 emissions" in proposing these performance standards. 77 Fed. Reg. at 22,399/3. Furthermore, in responding to interagency review comments on the draft proposed rule, EPA asserted that "EPA is still developing a biomass policy. The limits in this proposal did not consider biomass. We are adding a description of the process the agency is currently undertaking to address biomass for GHG emission reductions." EPA's Fifth Summary of Interagency Working Comments on Draft Language under EO12866/13563 Interagency Review, Docket ID. No. EPA-HQ-OAR-2011-0660-0030 at 16.

However, EPA does, in effect, exempt all biomass-fueled baseload and intermediate load power plants from the EGU GHG NSPS, unless they are designed to co-fire with fossil fuels at a heat input rate of more than 250 MMBtu per hr. 77 Fed. Reg. 22,398/1 (exempting biomass-fired boilers subject to subpart Db). EPA thus declines to include any greenhouse gas control requirement for this expanding and carbon-intensive component of the power sector. Biomass power plants are expected to provide a rapidly growing proportion of electricity generation

capacity over the next two decades. According to the Energy Information Administration, future renewable generation will be dominated by wind and biomass.[172]

The exemption is not only arbitrary in its own right, but also contradicts the rationales EPA advances for the NSPS as a whole. EPA's rationale for creating a new subpart TTTT from subparts KKKK and Da, is to adopt a single GHG performance standard "for plants that perform the same essential function, which is to provide generation to serve baseload or intermediate load demand." 77 Fed. Reg. 22,410/3. But if it is "sensible to treat as part of the same category units that generate baseload or intermediate load electricity, regardless of their design of fossil fuel type," *id.*, so too it is irrational to exclude biomass burning power plants that serve this function.

Nor does EPA's 2011 Biomass Deferral Rule, 76 Fed. Reg. 43,490 (July 20, 2011), preclude the calculation of biogenic emissions when evaluating and determining an EGU's compliance with the proposed NSPS. EPA agrees that that final rule, the legality of which is currently the subject of litigation in the U.S. Court of Appeals for the D.C. Circuit, *CBD, et al. v. EPA*, No. 11-1101, pertains only to the question whether biogenic emissions are "subject to regulation" and affect applicability under the PSD and Title V programs and not to any other EPA program. 76 Fed. Reg. at 43,492. The Biomass Deferral Rule amended 40 CFR Part 71, by creating an exception for certain sources that are required to obtain a federal operating permit. As it relates to 40 C.F.R. Part 75 (CEMS provisions), the biogenic exemption is simply a post-processing directive for purposes of the Act's permit program and for those purposes only. The NSPS proposal by contrast does not contain such a post-process directive, but instead requires facilities to demonstrate compliance-using data collected under Part 75 Appendix G, which does not provide any exemption for biogenic CO_2 emissions. An EGU that is subject to the NSPS must include the mass emission measurement of all of the fuels it burns, including biomass as required in 40 CFR Part 75. 77 Fed. Reg. 22,437 (proposed 40 CFR §60.5535).

Furthermore, the Biomass Deferral Rule amended the definition of "subject to regulation" under 40 CFR §70.2 to exclude CO_2 emissions from biogenic facilities when determining when a facility is a major source under the Title V program. However, pursuant to 40 CFR §70.3(a)(2), facilities covered under Section 111, and thus subject to the proposed rule, are also considered

[172] U.S. EIA, Annual Energy Outlook 73-74 (2011).

major sources under the Title V program. Nothing in 40 CFR Part 70 adopts a biogenic CO_2 exclusion for the calculation of mass emissions under 40 CFR Part 75. Thus, all CO_2 emissions from affected facilities under the proposed rule must be included when determining compliance.

The proposed rule subjects facilities with a base load rating of greater than 250MMBtu/h (73 MW) of fossil fuel, independent of the type of fuel that it actually burns. *See* 77 Fed. Reg. 22,436/2 (proposed 40 C.F.R §60.5509). It is unclear whether a facility that is designed to burn fossil fuels but *instead* burns biomass (whole trees, for example), would be subject to the proposed NSPS. EPA should clarify this point, to avoid perverse incentives to fuel switch to more carbon-intensive fuels in order to avoid the EGU CO_2 NSPS.[173] Therefore, a biogenic-fueled EGU that has a base load rating greater than 250MMBtu/h (73 MW) of a fossil fuel must include all CO_2 emissions when calculating mass emissions of CO_2 to determine compliance with the proposed rule.

[173] *See, e.g.,* T. Stecker, *Burning Wood for energy will hasten climate change – study*, E&E News (Monday June 4, 2012) describing the release of a new study by Steven Mitchell, of Duke University and Mark Harmon of Oregon State University, showing that the collection of wood and its combustion for energy generation could accelerate the pace of climate change in the near term.