- TECHNICAL SUPPORT DOCUMENT –

To: Docket EPA-HQ-OAR-2013-0495

Date: January 8, 2014

Subject: Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs

Introduction and Overview

By notice dated January 8, 2014, the Environmental Protection Agency (EPA) published the proposed rule, "Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 1430 (referred to here as the 2014 Proposal). In this action, the Agency proposes to establish new source standards of performance under Clean Air Act (CAA) §111(b) for fossil fuel-fired electricity generating units, including a standard of 1,100 pounds of carbon dioxide (CO_2) per gross megawatt-hour (lb CO_2/MWh) for steam generating boilers and integrated gasification combined cycle (IGCC) units. EPA based this standard on the proposed determination that new efficient generating technology implementing partial carbon capture and storage technology (CCS) is the best system of emission reduction adequately demonstrated (BSER) for those sources. EPA based this determination, in turn, on a review of existing projects that implement CCS, existing projects that implement various components of CCS, planned CCS projects, and scientific and engineering studies of CCS.

Some of the projects discussed in the 2014 Proposal received financial assistance under the Energy Policy Act of 2005 (P.L. 109-58) (EPAct05). This assistance includes various grants, loan guarantees, and other forms of assistance, as well as the Federal tax credit for investment in clean coal technology under Internal Revenue Code (IRC) §48A. Several provisions in EPAct05 explain the relevance of such projects to an EPA determination of BSER under CAA §111. These provisions are found in several parts of EPAct05: sections 402(a), 402(i), and 1307(b), as discussed below and 1307(b)(adding IRC §48A(g), as discussed below).

Through this technical support document (TSD), EPA solicits comment on its proposed views as to the meaning and significance of relevant provisions of EPAct05, including how these provisions may affect the rationale for EPA's proposed determination that partial CCS is the best system of emission reduction adequately demonstrated for fossil fuel-fired utility boilers and IGCC units. This TSD has two parts. In the first section, EPA summarizes the rationale it presented in the 2014 Proposal, and describes why the EPAct05 is most relevant for EPA's proposed determination that partial CCS is technically feasible and of reasonable cost. In the second section, EPA describes the applicable EPAct05 provisions, including IRC §48A(g). As discussed in greater detail below, EPA interprets these provisions to preclude EPA from relying solely on the experience of facilities that received EPAct05 assistance, but not to preclude EPA from relying on the experience of such facilities in conjunction with other information. In light of this interpretation, EPA explains its reliance on other information in making the determination that partial CCS is the BSER. EPA also explains that IRC §48A(g) presents a number of issues of interpretation that could affect the applicability and scope of that provision's limit on the use of information in CAA §111 rulemakings. EPA believes that even if IRC §48A(g) is interpreted to preclude EPA from, under any circumstances, relying on the experience of facilities that have been identified as having been allocated the IRC §48A tax credit, the remaining information set forth in the 2014 Proposal nonetheless provides an adequate basis for EPA's proposed determination.

Summary of 2014 Proposal of Rationale for BSER and Factors Affected by EPAct05

Best system of emission reduction adequately demonstrated

In the preamble for the 2014 Proposal, EPA discussed in some detail its interpretation of the requirements under CAA §111 for determining the "standard of performance," and readers are referred to that discussion. For convenience, parts of that discussion are excerpted here. In that discussion, EPA provided the following overview of its interpretation (citations omitted):

> By its terms, the definition of "standard of performance" under CAA section 111(a)(1) provides that the emission limit that the EPA promulgates must be "achievable" and must be based on a system of emission reduction – generally, but not required to be always, a technological control -- that the EPA determines to be the "best system" that is "adequately demonstrated," "taking into account … cost … nonair quality health and environmental impact and energy requirements." The D.C. Circuit has stated that in determining the "best" system, the EPA must also take into account "the amount of air pollution" and "technological innovation."
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> As discussed below, the D.C. Circuit has elaborated on the criteria and process for determining whether a standard is "achievable," based on an "adequately demonstrated" technology or system. In addition, the Court has identified limits on the costs and other factors that are acceptable for the technology or system to qualify as the "best." The Court has also held that the EPA may consider the costs and other factors on a regional or national level (e.g., the EPA may consider impacts on the national economy and the affected industry as a whole) and over time, and not just on a plant-specific level at the time of the rulemaking. In addition, the Court has emphasized that the EPA has a great deal of discretion in weighing the various factors to determine the "best

system."[1]

For present purposes, the technical feasibility and costs are the factors that may be primarily affected by the limits imposed by EPAct05 on information EPA may rely on under CAA §111 in finding that the BSER is adequately demonstrated. In the 2014 Proposal, EPA explained its interpretation of the requirements concerning technical feasibility as follows (citations omitted):

> The D.C. Circuit's first decision under section 111, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973), concerned whether EPA's standard of performance for the cement industry met the requirement to be "achievable," which, in turn, depended on whether the technology on which EPA based the standard was "adequately demonstrated." In this case, the Court interpreted these provisions to require that the technology must be technically feasible for the source category, and established criteria for determining technical feasibility.
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> The Court explained that a standard of performance is "achievable" if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard. Specifically, the D.C. Circuit explained:
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>> Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for new plants....- It is the "achievability" of the proposed standard that is in issue....
>>
>> The Senate Report made clear that it did not intend that the technology "must be in actual routine use somewhere." The essential question was rather whether the technology would be available for installation in new plants.... The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry.[2]

EPA discussed costs by noting that the D.C. Circuit has elaborated on the cost factor in several cases, and has identified limits to how costly a control technology may be before it no longer qualifies as the BSER. EPA explained that the Court has used various formulations of the cost standard, such as that the costs cannot be "excessive"

[1] 79 Fed. Reg. at 1463/1.
[2] 79 Fed. Reg. at 1463/2-3.

or "unreasonable." EPA added, "For convenience, in this rulemaking, we will use reasonableness as the standard, so that a control technology may be considered the "best system of emission reduction … adequately demonstrated" if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable."[3]

Basis for determination in 2014 Proposal for technical feasibility and costs

In the 2014 Proposal, the EPA evaluated three alternative control technology configurations as potentially representing the BSER for new fossil fuel-fired boilers and new IGCC units. The three alternatives are: (1) highly efficient new generation technology that does not include any level of CCS, (2) highly efficient new generation technology with "full capture" CCS (capture of at least 90 percent of CO_2 emissions), and (3) highly efficient new generation technology with "partial capture" CCS (capture of a smaller portion of the total CO_2 emissions). EPA discussed each of the alternatives in detail in the proposal and explained why it determined that partial CCS qualifies as the BSER. EPA also included its rationale for selecting 1,100 lb CO_2/MWh as the emission limitation for these sources and we explained its rationale for the requirements for geologic storage of the captured CO_2.

In brief, EPA stated that partial CCS has three core components: CO_2 capture, compression and transportation, and injection and storage of the CO_2 stream. EPA explained that each of these core components has already been implemented. Projects that implement various components of CCS include full commercial scale projects that implement all three components, full scale projects that implement one or more of the individual components and smaller scale projects that implement one or more of the components. It is not necessary that the major components be demonstrated in an integrated process in order to determine the technical feasibility of each component. Nor is it necessary that all of the components be demonstrated at an electricity generating plant.

In particular, EPA based its proposed determination that the technical feasibility of partial CCS is adequately demonstrated on a set of evidence that EPA summarized as follows:

> The EPA proposes to find that partial CCS is feasible because each step in the process has been demonstrated to be feasible through an extensive literature record, fossil fuel-fired industrial plants currently in commercial operation and pilot-scale fossil fuel-fired EGUs currently in operation, and the progress towards completion of construction of fossil fuel-fired EGUs implementing CCS at commercial scale.[4]

[3] 79 Fed. Reg. at 1464/2-3
[4] 79 Fed. Reg. at 1471/2.

In the 2014 Proposal, EPA based its estimation of the costs of partial CCS primarily on a report by the Department of Energy (DOE) National Energy Technology Laboratory (NETL)[5]. This report identified any new plants as "next of a kind," and estimated the amount of costs of CCS for such new plants accordingly. EPA based its proposed determination that these costs were reasonable on the fact that they are comparable to the costs of new construction of other low-carbon electricity generating power plants, including nuclear power plants.

EPAct05 Provisions, including IRC §48A, and EPA's interpretation

The Energy Policy Act of 2005 (EPAct05) addresses energy production in the United States, and contains provisions concerning, among other things: energy efficiency; renewable energy; oil and gas; coal; Tribal energy; nuclear matters and security; vehicles and motor fuels, including ethanol; hydrogen; electricity; hydropower and geothermal energy; climate change technology; and energy tax incentives, including Internal Revenue Code (IRC) §48A. Because the relevant provisions of IRC §48A differ from the other relevant provisions in EPAct05, IRC §48A will be discussed after the other relevant EPAct05 provisions.

Provisions in EPAct05 other than IRC §48A

EPAct05 authorized a number of coal-related programs. Title IV authorized $200 million annually for the Clean Coal Power Initiative between fiscal year (FY) 2006 through FY2014. Of this amount, 70% was designed for funding coal-based gasification technologies.

Section 402(i) of the EPAct05, codified at 42 USC section 15962(i), limits the use of information from facilities that receive assistance under the Act in CAA §111 rulemaking, as follows:

> "No technology, or level of emission reduction, <u>solely</u> by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated for purposes of section 111 of the Clean Air Act…. " (Emphasis added).

In addition, EPAct05 §421(a) amended the Energy Policy Act of 1992 (42 U.S.C. 13201 et seq.) (EPAct92) by adding the "Clean Air Coal Program" to support and promote the production and generation of clean coal-based power, including supporting air pollution control technologies. EPAct05 §421(a) included a constraint similar to EPAct05 §402(i).[6] EPAct05 offered other benefits to coal-fired power plants, including

[5] The "Cost and Performance Baseline" reports are a series of reports by DOE/NETL that establish estimates for the cost and performance of combustion- and gasification-based power plants - all with and without CO_2 capture and storage. Available at http://netl.doe.gov/research/energy-analysis/energy-baseline-studies;"Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture", DOE/NETL-2011/1498, May 27, 2011.

[6] As amended by EPAct05 §421(a), EPAct92 §3103(e) (42 U.S.C. 13573(e)) and EPAct92 §3104(d) (42 U.S.C. 13574(d)), provide:

loan guarantees under Title XVII (42 U.S.C. 16511-16514), research and development (R&D) grants under Title IX, and a tax credit for industrial facilities, IRC §48B. [7]

By their terms, EPAct05 §§402(i) and 421(a) prohibit EPA from relying exclusively – "solely" – on facilities that receive assistance under EPAct05 when determining whether a particular technology, or level of emission reduction, is adequately demonstrated for purposes of section 111 of the Clean Air Act. EPA thus may rely on such projects for its BSER determination if there is additional evidence supporting such a determination.

EPA solicits comment on the meaning of EPAct05 §§402(i) and 421(a). In particular, does the partial prohibition apply to any technology or emissions reduction by any facility receiving any form of assistance, regardless of whether the assistance relates to the technology or emission reductions; or, instead, does the prohibition apply to only the technology or emissions reduction for which the assistance was given. EPA believes that a reasonable reading is that the prohibition relates only to the technology or emissions reduction for which assistance was given. This reading is not only a natural one, but the other reading – under which there would be no connection between the government assistance and the technology/performance which is the subject of the partial prohibition—is strained. If the provision is ambiguous, EPA's interpretation would be accorded deference.[8]

In the 2014 Proposal and in this TSD, EPA relies on a wide range of information to support the proposed determination that partial CCS is the best system of emission reduction adequately demonstrated. This includes literature reviews, the experience of facilities that pre-date EPAct05, the experience of facilities in foreign nations, and projects that have been developed after the enactment of EPAct05, only some of which have received assistance under EPAct05. Accordingly, the proposed determination is not "solely" based on information about facilities that received assistance under EPAct05.

EPA solicits comment on all aspects of EPAct05 §402(i) and §421(a) as they related to the 2014 Proposal and this TSD, including the proper interpretation of those provisions, their application to EPA's proposed determination that partial CCS is the best system of emission reduction adequately demonstrated, and the types of assistance provided under EPAct05. EPA also requests that the owners or operators of facilities identified in the 2014 Proposal and this

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> Applicability. -- No technology, or level of emission reduction … shall be treated as adequately demonstrated for purpose of section 111 of the Clean Air Act (42 U.S.C. 7411), achievable for purposes of section 169 of that Act (42 U.S.C. 7479), or achievable in practice for purposes of section 171 of that Act (42 U.S.C. 7501) solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under [section 3102(a)(1) or (2) of the Energy Policy Act of 1992, as amended (42 U.S.C. 13572(a)(1))].

[7] It should be noted that IRC §48B does not itself contain any provision, comparable to EPAct 05 §402(i) or as discussed below, IRC §48A(g), limiting the use of information for purposes of determinations under the Clean Air Act.

[8] EPA would be the agency authorized to interpret 42 USC section 15962 because it involves the meaning of the Clean Air Act, and substantial deference would be accorded EPA's interpretation. See *Pension Benefit Guar. Corp. v. LTV Corp.*, 496 U.S. 633, 651-52 (1990) ("practical agency expertise is one of the principal justifications behind *Chevron* deference.").

TSD as part of EPA's basis for that proposed determination confirm, during the comment period, whether they did or did not receive assistance under EPAct05. EPA solicits comment on whether, if it does not receive information confirming that a particular facility received assistance under EPAct05, EPA may treat that facility as not having received any such assistance for purposes determining, in this rulemaking, the best system of emission reduction adequately demonstrated.

IRC §48A

Section 1307(b) of the EPAct05 amends the Internal Revenue Code to add §48A, which creates, as an investment tax credit, the "qualifying advanced coal project credit." In accordance with IRC §48A(d)(1), the Secretary of the Treasury (hereinafter referred to as the IRS), in consultation with the Secretary of Energy, established a "qualifying advanced coal project program" for the allocation of the authorized tax credits to projects. As noted below, subsequent congressional amendments added two more phases to this program, so that the original program may be referred to as Phase I. According to an IRS notice describing §48A (as enacted in EPAct05) and this (Phase I) program:

> .02 The qualifying advanced coal project credit is provided under [IRC] § 48A…. Section 48A(a) provides that the qualifying advanced coal project credit for a taxable year is an amount equal to (1) 20 percent of the qualified investment (as defined in § 48A(b)) for that taxable year in certified qualifying advanced coal projects (as defined in § 48A(c)(1) and (e)) using an integrated gasification combined cycle (IGCC) (as defined in § 48A(c)(7)), and (2) 15 percent of the qualified investment for that taxable year in other certified qualifying advanced coal projects.
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> .03 Section 48A(d)(3)(A) provides that the aggregate credits allowed under § 48A(a) may not exceed $1.3 billion. Section 48A(d)(3)(B) provides that (i) $800 million of credits are to be allocated to IGCC projects, and (ii) $500 million of credits are to be allocated to projects that use other advanced coal-based generation technologies (as defined in § 48A(c)(2) and (f)).
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> .04 Section 48A(e)(3)(A) provides that the credits for IGCC projects must be allocated in accordance with the procedures set forth in § 48A(d), and in relatively equal amounts to (i) projects using bituminous coal as a primary feedstock, (ii) projects using subbituminous coal as a primary feedstock, and (iii) projects using lignite as a primary feedstock. Further, § 48A(e)(3)(B) provides that IGCC projects that include (i) greenhouse gas capture capability (as defined in § 48A(c)(5)), (ii) increased by-product utilization, and (iii) other benefits must be given high priority in the allocation of credits for IGCC projects.

> .05 The at-risk rules in [IRC] § 49 and the recapture and other special rules in [IRC] § 50 apply to the qualifying advanced coal project credit. Further, the qualifying advanced coal project credit generally is allowed in the taxable year in which the eligible property (as defined in § 48A(c)(3)) is placed in service by the taxpayer. Pursuant to § 48A(D)(2)(E), a taxpayer that receives a certification under § 48A(d)(2)(D) has 5 years from the date of issuance of the certification to place the qualifying advanced coal project in service.[9]

A project is a "qualifying advanced coal project" that the IRS may certify (under §48A(d)(2)) if it meets the requirements of §48A(e), which include, among other things, that the project must "use[] an advanced coal-based generation technology" to power a new, or to retrofit or repower an existing, "electric generation unit" (as defined in §48A(c)(6)); the fuel input for the project must be at least 75% coal; the project must be of at least a specified size; the majority of the project's output must reasonably be expected to be acquired or utilized; and the project must be located in the U.S. Under §48A(f), an electric generation unit uses an "advanced coal-based generation technology" if the unit uses either integrated gasification combined cycle (IGCC) technology or has a design net heat rate of a specified amount, and if the unit meets other requirements, including being designed to attain specified standards for emissions or removal of certain criteria and hazardous air pollutants.

The term "qualified investment" is defined, under §48A(b)(1) as, for any taxable year, "the basis of eligible property placed in service by the taxpayer during such taxable year." In turn, "eligible property" is defined as –

> (A) in the case of any qualifying advanced coal project using an integrated gasification combined cycle, any property which is a part of such project and is necessary for the gasification of coal, including any coal handling and gas separation equipment, and
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> (B) in the case of any other qualifying advanced coal project, any property which is part of such project.

As described in more detail below, the IRS allocated the credit available under §48A – as enacted by EPAct05 – to a number of projects. However, under the taxpayer privacy rules, no information about any of these projects was made publicly available unless a recipient waived its privacy rights. In light of subsequent modifications to IRC §48A, discussed next, the program as enacted by EPAct05 became known as the Phase I program.

IRC §48A was expanded and modified by the Energy Improvement and Extension Act of

[9] Internal Revenue Bulletin: 2006-11 (Notice 2006-24, March 13, 2006). http://www.irs.gov/irb/2006-11_IRB/ar09.html

2008, Pub. L. 110-343, 122 Stat. 3765 (October 3, 2008) , which established Phase II of the program. According to an IRS notice –

> Section 111 of that Act amended § 48A to provide for a second phase of the qualifying advanced coal project program in which $1.25 billion of additional credits are authorized ("the Phase II advanced coal program" and "the Phase II advanced coal credit").[10]

As further described by the IRS, the revisions to IRC §48A –

> provide[] that the qualifying advanced coal project credit for a taxable year is an amount equal to (1) 20 percent of the qualified investment (as defined in § 48A(b)) for that taxable year in qualifying advanced coal projects (as defined in § 48A(c)(1) and (e)) described in § 48A(d)(3)(b)(i), (2) 15 percent of the qualified investment for that taxable year in qualified advanced coal projects described in § 48A(d)(3)(b)(ii), and (3) 30 percent of the qualified investment for that taxable year in qualifying advanced coal projects described in § 48A(d)(3)(B)(iii). Section 48A(d)(3)(b)(i) describes integrated gasification combined cycle ("IGCC") projects (as defined in § 48A(c)(7)) for which applications were submitted during the Phase I application period ("Phase I IGCC projects"). Section 48A(d)(3)(b)(ii) describes projects that use other advanced coal-based generation technologies (as defined in § 48A(c)(2) and (f)) and for which applications were submitted during the Phase I application period ("other Phase I advanced coal projects"). Section 48A(d)(3)(b)(iii) describes projects that use advanced coal-based generation technologies and for which applications are submitted during the Phase II application period ("Phase II advanced coal projects"). Phase II advanced coal projects include both IGCC projects and projects that use other advanced coal-based technologies. For this purpose, the Phase I application period is the 3-year period following the establishment of the qualifying advanced coal program on March 13, 2006, and the Phase II application period is the 3-year period beginning on March 13, 2009.
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> .04 Section 48A(d)(3)(A) provides that the aggregate credits allowed under § 48A(a) may not exceed $2.55 billion. Section 48A(d)(3)(B) provides that (1) $800 million of credits are to be allocated to Phase I IGCC projects, (2) $500 million of credits are to be allocated to other Phase I advanced coal projects, and (3) $1.25 billion of credits are to be allocated to Phase II advanced coal projects.

[10] Internal Revenue Bulletin: 2009-16 (Notice 2009-24, April 20, 2009) http://www.irs.gov/irb/2009-16_irb/ar07.html

> .05 Section 48A(d)(2)(A) provides that (i) applications for the credits allocated to Phase I IGCC projects and other Phase I advanced coal projects may be submitted only during the Phase I application period, and (ii) applications for the credits allocated to Phase II advanced coal projects may be submitted only during the Phase II application period.
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> .06 Section 48A(d)(5) provides that the Secretary [of the Treasury] shall, upon making a certification under § 48A(d), publicly disclose the identity of the applicant and the amount of the credit certified with respect to such applicant.
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> .07 Section 48A(e)(1)(G) provides that any project the application for which is submitted during the Phase II application period must include equipment that separates and sequesters—
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> (1) At least 65 percent of such project's total carbon dioxide ("CO_2") emissions in the case of an application other than an application for reallocated credits under § 48A(d)(4); and
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> (2) At least 70 percent of such project's total CO_2 emissions in the case of an application for reallocated credits under § 48A(d)(4)….
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> .11 Section 48A(i) provides that the Secretary shall provide for recapturing the benefit of any credit allowable under § 48A(a) with respect to any project that fails to attain or maintain the separation and sequestration requirements of § 48A(e)(1)(G).[11]

In 2012, the IRS established Phase III of this program, which, according to the IRS, was designed "to distribute the §48A Phase I credits that are available for allocation after the conclusion of the §48A Phase I program."[12]

The following information has been made publicly available about the taxpayers who have been allocated the §48A tax credits in the three phases of the program:_For Phase I, in 2006, the IRS and the DOE announced that nine clean coal and advanced gasification projects had been awarded[13] tax credits under IRC §48A or §48B. (As noted above, unlike IRC §48A, IRC §48B does not itself contain any provision that limit the use of information about recipients of the §48B tax credit.) According to the IRS, the awards involved two IGCC bituminous coal projects, one IGCC lignite project, two non-IGCC

[11] Id.

[12] Internal Revenue Bulletin: 2012-33 (Notice 2012-51, August 13, 2012). http://www.irs.gov/irb/2012-33_IRB/ar05.html#d0e358

[13] In its announcements, the IRS sometimes describes the allocations as "awards." Those two terms – allocation and award – are synonymous.

advanced coal electricity generation projects, and four gasification projects.[14] The following information as to seven of these sources was made publicly available by the DOE. [15] (It should be noted that the information from the IRS and DOE does not explicitly state which facilities were allocated the tax credit under IRC§48A and which under IRC §48B.)

Technology	Recipient	Location	Output	Tax Credit
IGCC Bituminous	Duke Energy – Edwardsport IGCC Project	Edwardsport, IN	795 MW	$133.5 million
IGCC Bituminous	Tampa Electric	Polk County, FL	789 MW	$133.5 million
IGCC Lignite	Mississippi Power Company	Kemper County, MS	700 MW	$133 million
Advanced Coal	Duke Energy Cliffside Modernization projects	Cleveland and Rutherford Counties, NC	1600 MW	$125 million
Advanced Coal	E.ON U.S., Kentucky Utilities Co. and Louisville Gas and Electric	Bedford, KY	1744 MW	$125 million
Gasification	Carson Hydrogen Power, LLC: Carson Hydrogen Power Project	Carson, CA	Hydrogen and 390 MW of electricity	N/A
Gasification	TX Energy, LLC: Longview Gasification and Refueling Project	Longview, TX	Synthetic gas for chemical feedstock	N/A

For Phase II, according to the IRS, the following information is available as to the awards of credits, which concerned the 2009-10 and 2011-12 allocation rounds.[16]

[14] IRS Press Release IR-2006-184 (Nov. 30, 2006).
[15] "Fact Sheet: Clean Coal Technology Ushers In New Era in Energy," U.S. Department of Energy, http://energy.gov/downloads/fact-sheet-clean-coal-technology-ushers-new-era-energy
[16] IRS Announcement 2010-56, 2010-39 I.R.B. 398 (September 27, 2010) and IRS Announcement 2013-2, 2013-2 I.R.B 271 (January 7, 2013). During the 2009-10 allocation round, the IRS also awarded §48B tax credits to Faustina Hydrogen Products ($121,660,000) and Lake Charles Gasification, LLC ($128,340,000). IRS Announcement 2010-56. On October 3, 2011, the Service issued Announcement 2011-62, 2011-40 I.R.B. 483, announcing that the second allocation round in 2010-11 did not result in any allocation of the qualifying advanced coal project credit,

Program	Taxpayer	Amount of Credit Awarded	Total Credit Awarded
§48A			
	Christian County Generation, LLC	$417,000,000	
	Summit Texas Clean Energy LLC	$313,436,000	
	Mississippi Power Company	$279,000,000	
	Hydrogen Energy California LLC	$103,564,000	
			$1,113,000,000

For Phase III, according to the IRS, the following information is available as to the awards of credits, which concerned the 2012-13 allocation round:[17] (It should be noted that this information from the IRS does not explicitly state which facilities received the tax credit under IRC§48A and which under IRC §48B.)

Program	Taxpayer	Amount of Credit Awarded	Total Credit Awarded
Phase III			
	STCE Holdings, LLC	$324,000,000	
	SCS Energy California, LLC	$334,500,000	
			$658,500,000

IRC §48A(g) limits information concerning the use of technology or level of emission reduction from EGU facilities[18] for which a tax credit is allowed,[19] which prohibition is similar to those in the other EPAct05 provisions noted above. Specifically, §48A(g) provides (for purposes relevant here):

> No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated for purposes of section 111 of the Clean Air Act….

EPA solicits comment on the proper interpretation of all aspects of this provision,

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[17] IRS Announcement 2013-43. http://www.irs.gov/pub/irs-drop/a-13-43.pdf The IRS stated that "The 2012-2013 allocation round is the only allocation round under the Phase III program." Id.

[18] An "electric generation unit" is defined as "any facility at least 50 percent of the total annual net output of which is electrical power, including an otherwise eligible facility which is used in an industrial application."IRC section 48A(c)(6).

[19] Only an "electric generation unit" may receive the section 48A tax credit. See sections 48A (e)(1)(A) and (f)(1).

including several in particular. The first is the phrase "considered to indicate." In the present context, does the term "considered" mean "referred to", or "deemed,"[20] or something else? In addition, does the term "indicate" mean "support" or "prove," or something else? Depending on the answers to these questions, the phrase, "considered to indicate," could preclude only information providing the sole basis for a determination that a particular technology is the best system of emission reduction adequately demonstrated, or it could also preclude information which is only corroborative or is otherwise only part of the basis for the determination. That is, the phrase could have any one of three different meanings: (i) Information about a particular technology from certain facilities may not be used at all in a determination of whether that technology is the best system of emission reduction adequately demonstrated; (ii) such information may be used to corroborate such a determination, when that determination is based on other information; or (iii) such information may be used along with other information to make such a determination, but may not be used as the only basis.

EPA's proposed interpretation[21] of this provision is the third, that use of technology, or emission performance, from a facility for which the credit is allowed cannot, by itself, support a finding that the technology or performance level is adequately demonstrated, but the information can corroborate an otherwise supported determination or otherwise provide part of the basis for such a determination. EPA notes that this reading would parallel the meaning of the related provisions in EPAct05 §§402(i) and 402(a), including, e.g., 42 USC 15962(i). Since all of these provisions were part of the same legislation and address the same issue, and since there is no legislative history indicating that they were meant to have different meanings, this interpretation is reasonable. This interpretation also is consistent with the apparent purpose of IRC §48A – as well as the other types of assistance in EPAct05 -- which is to encourage the development of technology so that it can be used on a widespread commercial basis. As discussed in the preamble for the 2014 Proposal, CAA §111 is an important vehicle for promoting widespread commercial use of technology.

In addition, EPA interprets other terms in IRC §48A(g) as limiting the scope of the information preclusion. Importantly, §48A(g) raises an issue as to whether the limit on use of information applies to the evaluation of any technology or emissions reduction by any facility allowed the tax credit, regardless of whether the tax credit relates to the technology at issue in the determination of the best system of emission reduction adequately demonstrated or, instead, the limit applies to only the technology or emissions reduction for which the tax credit

[20] Under this view, in the intransitive form that section 48A(g) uses the verb "consider," the verb may be a synonym for "deemed," as in the phrase, "the accused shall be considered innocent until proven guilty."

[21] As with the related provisions of EPAct05, because 26 USC section 48A(g) involves the meaning of the Clean Air Act, EPA would be the agency authorized to interpret it.

was allowed. Specifically, does the phrase "with respect to which a credit is allowed under this section" refer to (i) the entire phrase "use of technology (or level of emission reduction …) and … achievement of any emission reduction…, by or at one or more facilities," or (ii) only "one or more facilities?" This distinction is important because the tax credit is available only for "eligible property," as defined under §48A(c)(3), and not for all technology that EPA may evaluate as part of the BSER. For example, as noted, for projects using IGCC, "eligible property" is defined as "any property which is a part of such project and is necessary for the gasification of coal, including any coal handling and gas separation equipment."

The most natural interpretation appears to be the first of those noted above, so that the phrase "with respect to which a credit is allowed under this section" refers to the entire phrase "use of technology (or level of emission reduction …) and … achievement of any emission reduction…, by or at one or more facilities." This reading also is consistent with the apparent purpose of the provision of not basing demonstrations of technology and performance solely on federally subsidized levels of performance. Under this interpretation, the prohibition in section 48A(g) would appear to be limited to the "eligible property" for which the tax credit is allowed. That is, if a unit is allowed the tax credit only with respect to technology A (for example, IGCC technology, as defined), then EPA is prohibited from reviewing the use of that technology in assessing the best system of emission reduction adequately demonstrated for purposes of CAA §111, but may review use of any other technology at the facility (for example, transportation or sequestration-related technology) in making that assessment. EPA solicits comment on all aspects of this issue of which technology at a facility that is allowed the §48A tax credit EPA may review in determining BSER. In addition, EPA solicits comment on the meaning of the phases, "level of emission reduction solely by reason of the use of the technology" and "achievement of any emission reduction by the demonstration of any technology or performance level."

EPA also solicits comment on questions as to the applicability of IRC§ 48A(g). Does the limitation occur only if and at the time when the tax credit "is allowed under [section 48A]" (and not before), and if so, when is that time? The IRS, in consultation with DOE, has set up a process, as part of the §48A(d) program, for administering the credit, under which a taxpayer may submit an application for the credit, the IRS and DOE may issue certifications, and the IRS may issue an allocation of the credit to the taxpayer. But these events are not the same as when the credit "is allowed." Section 48A does not, by its terms, specify the time when the credit "is allowed." The IRS has stated that "the … credit generally is allowed in the taxable year in which the eligible property … is placed in service by the taxpayer."[22] Under the Treasury

[22] IRB 2006-11 Notice 2006-24, section 2.05; IRB 2009-16, Notice 2009-24, section 2.12. There is case law and other IRS documents that address placed in service questions in the context of electric power plants. See, e.g.,

regulations, the taxable year in which property is "placed in service" is "the earlier of the following taxable years: (i) The taxable year in which, under the taxpayer's depreciation practice, the period for depreciation with respect to such property begins; or (ii) The taxable year in which the property is placed in a condition or state of readiness and availability for a specifically assigned function …." 26 CFR §1.46-3(d)(1).[23] We solicit comment on issues associated with determining when the §48A credit "is allowed." For example, if EPA may review technology at a particular facility in a rulemaking that is finalized before such technology is placed in service at that facility, if the technology is subsequently placed in service – either in the same year in which the rulemaking is finalized or a later year – does the fact that the credit has been allowed become relevant?[24]

In addition, EPA solicits comment on a set of issues that arise due to taxpayer privacy rights. Because of those rights, there is a limited amount of information about the facilities affected by IRC §48A that is available to EPA. EPA does not have complete information as to which of the facilities were allocated the tax credit during Phase I (2006-2009); as noted above, EPA is aware of only the facilities that waived privacy rights. Moreover, EPA does not have specific information as to which of each facility's property is treated as the "eligible property" for which the tax credit was allocated. Nor does EPA have complete information as to the actual "use of [the] technology (or level of emission reduction solely by reason of the use of the technology)" or the actual "achievement of any emission reduction by the demonstration of [such] technology or performance level." Nor does EPA have complete information as to whether, for any facility allocated the tax credit, (i) the allocated tax credit was forfeited because the eligible property was not placed in service by the applicable deadline or (ii) the tax credit was allowed within the meaning of IRC §48A(g).

EPA solicits comment on all aspects of §48A(g), including the interpretation of the provisions noted above. In addition, EPA invites facilities affected by IRC §48A to submit, during the public comment period for the 2014 Proposal, relevant information, including information described in the immediately preceding paragraph, as is consistent with their privacy concerns. Further, EPA solicits comment on how it should proceed with its determination of the best

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Olgethorpe Power Corp. v. Commissioner, T.C. Memo. 1990-505; Consumers Power Co. v. Commissioner, 89 T.C. 710 (1987); Rev. Rul. 76-256, 1976-2 C.B. 46.

[23] The Treasury regulations provide "examples of cases where property shall be considered in a condition or state of readiness and availability for a specifically assigned function." 26 CFR §1.46-3(d)(2).

[24] As another matter of timing, the EPA solicits comment on whether the references to "use of technology" and "achievement of … emission reduction" mean that the only information that is precluded is information that the facility is *actually* using the technology or is *actually* achieving emission reductions, as opposed to other information, such as that the facility is *planning* to use the technology. Arguably, interpreting the limitation to apply only to actual use may be consistent with interpreting the limitation to apply only when the tax credit is allowed, which, as noted, is when the property is placed in service.

system of emission reduction adequately demonstrated under CAA §111(a)(1) if, by the time of the final rulemaking, it lacks relevant information – such as that described above -- with respect to facilities affected by IRC §48A. In particular, should EPA be precluded from relying on the "use of technology (or level of emission reduction solely by reason of the use of the technology)" or "achievement of any emission reduction by the demonstration of any technology or performance level" by or at any particular facility only if EPA has sufficient information concerning such technology or emission reduction for which the §48A tax credit was allocated, and that the §48A tax credit has been "allowed?"[25]

Determination that Partial CCS is the Best System of Emission Reduction

The EPA evaluated three alternative control technology configurations as potentially representing the best system of emission reduction adequately demonstrated (BSER) for new fossil fuel-fired boilers and IGCC units. The three alternatives are: (1) highly efficient new generation technology that does not include any level of CCS, (2) highly efficient new generation technology with "full capture" CCS (capture of at least 90 percent of CO_2 emissions), and (3) highly efficient new generation technology with "partial capture" CCS (capture of a smaller portion of the total CO_2 emissions). EPA discussed each of the alternatives in greater detail in the proposal, and explained why it determined that partial CCS qualifies as the BSER. EPA also included its rationale for selecting 1,100 lb CO_2/MWh as the emission limitation for these sources and explained its rationale for the requirements for geologic storage of the captured CO_2.

Technical Feasibility

The EPA proposed to find that partial CCS is technically feasible because each of its major components – the CO_2 capture, the compression and transportation, and the injection and storage of CO_2 – has been demonstrated to be technically feasible. This is noted in examples of facilities currently in operation or under development as well as an extensive literature record. These examples include both fossil fuel-fired EGUs and other industrial plants with characteristics very similar to EGUs currently in commercial operation, pilot-scale fossil fuel-fired EGUs currently in operation, and the progress towards completion of construction of fossil fuel-fired EGUs implementing CCS at commercial scale designed to achieve limits significantly below the proposed standard.

In discussing the rationale for the determination of BSER and the resulting proposed

[25] It should also be noted that credits are recaptured "with respect to any project which fails to attain or maintain the separation and sequestration requirements" of 65% or 70%. IRC §48A(i). EPA does not have complete information as to whether, for any taxpayer, the benefit of the tax credit was recaptured.

emission standards, the Agency referenced some plants and demonstration projects that have received financial assistance under the EPAct05 or that have been allocated an investment tax credit under IRC§ 48A.

As noted, the purpose of this TSD and the NODA it accompanies is to solicit comment on whether any pieces of the evidence presented in the 2014 Proposal may not be evaluated due to the limits imposed by the applicable EPAct05 provisions, including IRC §48A(g), and, if so, whether the remaining evidence is sufficient to support a finding that partial CCS is technically feasible. As further discussed below, if the EPAct05 limits have any significance, it is with respect to the capture component. The compression and transport as well as injection and storage components have long been well-established. This TSD also notes additional evidence, indicated below, that has come to our attention since the Administrator signed the 2014 Proposal. In light of the forward-looking nature of the determination of technical feasibility, based on information available to us as to which facilities have been allocated the §48A tax credit, even if we are obliged to exclude any information about those facilities, we retain an adequate basis for our determination of technical feasibility based on other available information, as explained below.

Technical Feasibility of CO_2 Capture Technology

Capture of CO_2 from industrial gas streams has occurred since the 1930s,[26] through use of a variety of approaches to separate CO_2 from other gases. In general, CO_2 capture technologies applicable to coal-fired power generation can be categorized into three approaches: (1) post-combustion systems that are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air; (2) pre-combustion systems that are designed to separate CO_2 from the high-pressure syngas produced at IGCC power plants; and (3) oxy-combustion systems that use high-purity O_2, rather than air, to combust fossil fuel and thereby produce a highly concentrated CO_2 stream. Each of these three carbon capture approaches is technologically feasible and has been demonstrated in other industries. Examples of each are summarized below.

Post-combustion capture

With regards to post-combustion CCS, in the 2014 Proposal, we relied on three types of projects: (1) small-scale capture projects operated commercially at coal-fired power plants, (2) demonstration projects at existing power plants, and (3) large-scale projects in advanced stages of development at commercial power plants. EPA cited in the preamble three projects that fall

[26] A process for capturing CO_2 from flue gas was granted a patent in 1930. "Process for Separating Acidic Gases", US Patent 1,783,901 (December 2, 1930).

into the first category: The AES Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) coal-fired power plants are equipped with post-combustion amine scrubbers developed by ABB/Lummus to capture CO_2 for use in the food processing industry.[27] The Searles Valley Minerals soda ash plant (Trona, CA) has captured CO_2 from the flue gas of a coal-fired power plant via amine scrubbing for use in the production of soda ash.[28] In each of these cases, small amounts of flue gas are treated, but a large percentage of CO_2 is removed (generally 90% or more) from the treated gas stream. The technologies used in these plants are the same types that would be evaluated for use at a new conventional coal-fired power plant. All three of these projects were developed and operated prior to EPAct05. These projects show that the technology can be designed, constructed and operated in a commercial power plant environment at smaller scales. While those projects entail relatively small amounts of CO_2 removal (the two largest projects are designed to capture about 800 tons CO_2 per day, about 13% of the amount a 500 MW coal plant would need to achieve a limit of 1,100 lb CO_2/MWh), the technology used can be scaled up. As noted above, under the case law, the determination of technical feasibility is forward-looking and may be based on reasonable projections, and here, EPA believes it is reasonable to project that the technology used by these projects can be scaled up. In particular, EPA believes the efforts at the Boundary Dam project alone demonstrate that companies are willing to pursue full-scale projects at this time. Other projects described below further validate this belief. Further, comments by vendors indicate that they believe they are capable of scaling up the technology. For instance, one vendor indicated as far back as 2009, the ability to supply a capture unit capable of capturing about 3,000 tons of CO_2 per day[29], approximately half the amount needed to meet the requirements of the proposed rule for a new 500 MW coal plant. Building a system with two of these units would meet the requirements of the proposed rule.

Projects that fall into the second category (demonstration projects) would include the 20 MW slip stream CCS demonstration at the AEP Mountaineer Plant in New Haven, WV. The demonstration using Alstom's patented chilled ammonia CO_2 achieved capture rates from 75 percent (design value) to as high as 90 percent, and produced CO_2 at purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent and captured and sequestered approximately 7,000 tons CO_2 per month during the period it operated. In addition to building

[27] Dooley, J. J., et al. (2009). An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.
[28] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.
[29] From Page 12 of Dooley, J. J., et al. (2009).

and operating a 20 MW slip stream, a significantly larger 240 MW project has been designed for the site (further indication of an ability to scale up the technology). At this time AEP has stated that it is not moving forward with the project, not due to technical concerns, but rather because AEP believes that the lack of a national CO_2 policy does not provide the necessary regulatory support for a project of this scale.[30,31] Another project is the 25 MW slip stream post-combustion capture project at Southern Company's coal-fired Plant Barry near Mobile, AL. The project uses a commercially available Mitsubishi Heavy Industries amine scrubbing system to capture CO_2 at a rate of over 90 percent. The captured CO_2 from Plant Barry is being transported to a nearby site for injection into a deep saline geologic formation.

Projects that fall into the third category (commercial scale) would include SaskPower's Boundary Dam CCS Project which is being constructed in Estevan, a city in Saskatchewan, Canada. The project is the world's largest commercial-scale CCS project of its kind. The project will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available post-combustion CCS technology to capture 90 percent of its CO_2 emissions. The captured CO_2 will be utilized for enhanced oil recovery (EOR) operations in nearby oil fields. The facility is currently under construction with full operation expected in 2014. To EPA's knowledge, the Boundary Dam project has not received any assistance under EPAct05.

Finally, NRG Energy is developing a commercial-scale post-combustion carbon capture project at the company's W.A. Parish generating station southwest of Houston, Texas. This project, which has received financial assistance from the EPAct05 CCPI, is expected to be operational in 2015 and provides a third example that the technology can be scaled up.

The information on which the 2014 Proposal relies, in conjunction with the literature and other information noted below, is by no means limited to facilities that received assistance under EPAct05 and, as result, the limitations on the use of information from such facilities do not preclude EPA from relying on such facilities, along with other information, to determine that post-capture is technically feasible. As noted above, EPA has incomplete information as to the facilities affected by the §48A tax credit. However, even if EPA cannot rely, in any manner,

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[30] AEP "is placing its plans to advance carbon dioxide capture and storage (CCS) technology to commercial scale on hold, citing the current uncertain status of U.S. climate policy and the continued weak economy as contributors to the decision". From a July 17, 2011 AEP press release (www.aep.com/newsroom/newsreleases/?id=1704).

[31] As part of Phase I, AEP and its partners developed a front-end engineering and design package for the commercial-scale that incorporated knowledge gained and lessons learned (construction and operations related) from the pilot system and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc. AEP Report prepared for The Global CCS Institute, Project #PRO 004, January 2012, "CCS Lessons Learned Report, American Electric Power Mountaineer CCS II Project Phase 1". Available at http://cdn.globalccsinstitute.com/sites/default/files/publications/32871/ccs-lessons-learned-report-gccsi-final-01-23-2012.pdf

on information from such facilities, the information available from other facilities, noted above, that do not appear to have been affected by the tax credit, along with the literature, is sufficient to demonstrate technical feasibility.

Pre-combustion Capture

In the proposed rule, we prominently discussed the development of the Kemper County Energy Center, the Texas Clean Energy Project, and the Hydrogen Energy California projects – all IGCC units that will capture at least 65 percent CO_2 capture for EOR operations. All of these facilities have received EPAct05 CCPI funding and have been allocated IRC section 48A tax credits. However, the technology that will be used in these projects – pre-combustion CO_2 capture from a syngas stream – is very well demonstrated technology. As a result, even if EPA is unable to rely in any manner on information from those facilities, EPA has sufficient information to determine that pre-combustion is technically feasible.

One of the best examples of pre-combustion CO_2 capture from a coal gasification stream is at the Dakota Gasification Company's Great Plains Synfuels Plant located in Beulah, North Dakota. While the facility is not an EGU, it is functionally very similar to an electric power producing IGCC plant. The plant is a coal gasification facility that uses North Dakota lignite to produce a syngas stream that is catalytically shifted to the desired composition of CO_2, CO and H_2. The facility then uses a pre-combustion Rectisol® system to capture the CO_2 before the syngas is converted to synthetic natural gas (i.e., methane) via a methanation process. The captured CO_2 is purified, compressed and transported via a 200-mile pipeline for use in EOR operations and storage in the Weyburn oil field in Saskatchewan, Canada. The facility began sending captured CO_2 to Canada in October 2000, reducing CO_2 emissions from the plant by about 45 percent. As of December 31, 2012, the facility had captured more than 24.5 million metric tons of CO_2. If the synthetic natural gas produced by the facility were utilized on-site in a combined cycle unit for power production, then the facility would be, for all practical purposes, an IGCC unit. This project demonstrates the ability of carbon capture and sequestration to be utilized with a fossil fuel gasification system creating synthetic natural gas that is compatible with existing natural gas combined cycle (NGCC) technology. These are all of the major components that would be needed at a new IGCC unit that was designed to meet the requirements of the proposed standards. From a capture standpoint, this project demonstrates the ability to separate and capture gas from a gasification system that could be used at an IGCC facility. The transportation, injection and storage components of this project are also directly applicable to an IGCC. The only part of an IGCC with CCS process that this project does not demonstrate is the integration of the gasification system with the combined cycle unit power block – a technology that is very well demonstrated. A number of existing IGCC projects without CCS (e.g., the Wabash River and Polk IGCC facilities) demonstrate the ability to construct and operate an integrated gasification and combined cycle unit. Collectively, these projects demonstrate the operation and integration of all of the major components of an IGCC with CCS. All of the major core components of CCS – the capture, the compression and transportation, and the injection and storage – have been successfully demonstrated at the Great Plains Synfuels Plant and the Weyburn oil field; and, as stated earlier, it is not necessary that all of those components be demonstrated at an electricity generating plant. Thus, the EPA believes that the experience at the Dakota Gasification Great Plains Synfuels Plant adequately demonstrates the technical feasibility of pre-combustion capture CCS and all of its core components.

The Coffeyville Gasification Plant in Coffeyville, Kansas is another example of industrial fossil-fuel gasification with subsequent CO_2 capture. The facility converts petroleum coke into a hydrogen-rich synthetic gas that is used to produce ammonia, urea and ammonium nitrate fertilizers as well as other chemicals. The CO_2 captured at the facility has been used internally for fertilizer production. Recently the capture capacity was increased and the additional captured CO_2 is being transported by pipeline to oil fields in Osage County, Oklahoma for use in EOR operations. The project, which commenced operation in 2013, is expected to capture nearly 1 million tonnes of CO_2 per year.

As with post-combustion capture, the above-described information, in conjunction with the literature and other information noted below, is not limited to technology from facilities that received assistance under EPAct05 and, as result, the limitations on the use of such information do not preclude EPA from relying on such information, along with other information, to determine that post-combustion capture is technically feasible. And also as with post-combustion capture, although EPA has incomplete information as to the facilities affected by the §48A tax credit, even if EPA cannot rely, in any manner, on information from such facilities, the information available from other facilities, noted above, that do not appear to have been affected by the tax credit, in conjunction with the literature and other information described below, is sufficient to demonstrate technical feasibility.

Oxy-combustion

In the 2014 Proposal, we relied on the technical feasibility and availability of post- and pre-combustion capture as the basis for our BSER determination. In addition, we also noted the additional option of oxy-combustion. Oxy-combustion of coal is being demonstrated in a 10 MWe pilot facility in Germany. The Vattenfall Schwarze Pumpe Power Station in eastern Germany has been operating since September 2008 and plans to operate for at least 10 years. It is designed to capture 70,000 tonnes of CO_2 per year.

A larger scale project – the FutureGen 2.0 Project – is in advanced stages of planning in the U.S.[32] This project is being jointly developed by DOE and industry partners and has received funding under provisions of EPAct05.

Carbon Capture and Mineralization

Other novel CO_2 capture and storage technologies are in the advanced stages of development and demonstration. For example, Skyonic[33] has developed a technology for the capture and permanent sequestration of CO_2 in mineral form (i.e., as carbonates). The company recently broke ground on a commercial-scale carbon capture and mineralization plant – the SkyMine® process – at a cement factory in San Antonio, TX. The facility, which will be completed and operational in 2014, will use proven chemical engineering components to capture CO_2 from a coal-fired boiler at the cement plant and sequester the CO_2 through mineralization. This process transforms the captured CO_2 into solid products, effectively storing CO_2 and generating revenue. The process is applicable to a wide variety of CO_2 gas streams and has been piloted at several coal-fired power plants.

Literature

The current status of CCS technology was described and analyzed by the 2010 Interagency Task Force on CCS, established by President Obama on February 3, 2010, co-chaired by the DOE and the EPA, and composed of 14 executive departments and federal agencies. The Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016. The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology challenges, and the current cost of CCS relative to other technologies, there are no insurmountable technological barriers that prevent CCS from playing a role in reducing GHG emissions.[34]

The Pacific Northwest National Laboratory (PNNL) recently prepared a study that evaluated the development status of various CCS technologies for the DOE[35]. The study

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[32] In cooperation with the U.S. Department of Energy (DOE), the FutureGen 2.0 project partners will upgrade a power plant in Meredosia, IL with oxy-combustion technology to capture approximately more than 90 percent of the plant's carbon emissions. http://www.futuregenalliance.org/.

[33] http://skyonic.com/

[34] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 7.

[35] Dooley, J. J., et al. (2009). An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.

addressed the availability of capture processes, transportation options (CO_2 pipelines), injection technologies, and measurement, verification and monitoring technologies. The study concluded that, in general, CCS is technically viable today and that key component technologies of complete CCS systems have been deployed at scales large enough to meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants. In addition, DOE's National Energy Technology Laboratory (NETL) has prepared other reports – in particular their "Cost and Performance Baseline" reports,[36] including one on partial capture[37] -- that further support our proposed determination of the technical feasibility of partial capture. The latter DOE-NETL report includes schematic diagrams and descriptions of both post-combustion and pre-combustion partial capture systems. It should be noted that while some literature may refer to facilities that have received assistance under EPAct05, a great deal of literature does not.

Other Industrial CCS Projects

The DOE/NETL currently lists three active projects under its Industrial Carbon Capture and Storage (ICCS) program. While none of these plants are EGUs, they are demonstrating the core components of CCS that could be directly applicable to a new fossil fuel-fired EGU – the capture, the compression and transportation, and the injection and storage.

Air Products and Chemicals, Inc. (Allentown, PA) has retrofitted its two Port Arthur, TX steam methane reformers (SMRs) with a vacuum swing adsorption (VSA) system to separate the CO_2 from the process gas stream, followed by compression and drying processes. This process, which began operation in May 2013, will concentrate the initial stream containing from 10-20 percent CO_2 to greater than 97 percent CO_2 purity.

Archer Daniels Midland Company (ADM, Decatur, IL) will demonstrate an integrated system for collecting CO_2 from an ethanol production plant and geologically sequester it in the Mt. Simon Sandstone, a saline reservoir in the Illinois Basin.

Leucadia Energy, LLC (Lake Charles, LA) will demonstrate the capture of CO_2 from an industrial petroleum coke gasification facility (that produces methanol and other chemicals). The captured CO_2 will be transported to oil fields in Texas for use in EOR operations.

[36] The "Cost and Performance Baseline" reports are a series of reports by DOE/NETL that establish estimates for the cost and performance of combustion- and gasification-based power plants - all with and without CO_2 capture and storage. Available at http://netl.doe.gov/research/energy-analysis/energy-baseline-studies.

[37] "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture", DOE/NETL-2011/1498, May 27, 2011.

Global CCS Institute Assessment

In its most recent "Global Status of CCS 2013: A Summary,"[38] the Global CCS Institute[39] found that "CCS technology is well understood, and a reality." They also stated that "CCS is often mistakenly perceived as an unproven or experimental technology. In reality, the technology is generally well understood and has been used for decades at a large scale in certain applications." The report noted that CCS is happening now and continuing to grow at a strong pace, with 12 large–scale integrated projects in operation. These projects are listed in the table below. Again, while none of these plants are EGUs, they are demonstrating the core components of CCS that could be directly applicable to a new fossil fuel-fired EGU – the capture, the compression and transportation, and the injection and storage.

Worldwide Large-scale Integrated CCS Projects in Operation Identified by Global CCS Institute

Project	Location	Storage	Industry
Air Products Steam Methane Reformer EOR Project	USA	EOR	Hydrogen Production
Century Plant	USA	EOR	Natural Gas Processing
Coffeyville Gasification Plant	USA	EOR	Fertilizer Production
Enid Fertilizer CO_2-EOR Project	USA	EOR	Fertilizer Production
Great Plains Synfuel Plant and Weyburn-Midale Project	USA/Canada	EOR	Synthetic Natural Gas
In Salah CO_2 Storage	Africa	Deep saline injection	Natural Gas Processing
Lost Cabin Gas Plant	USA	EOR	Natural Gas Processing
Petrobras Lula Oil Field CCS Project	Brazil	EOR	Natural Gas Processing
Shute Creek Gas Processing Facility	USA	EOR	Natural Gas Processing
Sleipner CO_2 Injection	Europe	Deep saline injection	Natural Gas Processing
Snøhvit CO_2 Injection	Europe	Deep saline injection	Natural Gas Processing
Val Verde Natural Gas Plants	USA	EOR	Natural Gas Processing

[38] Available at http://www.globalccsinstitute.com/publications/global-status-ccs-2013

[39] The Global Carbon Capture and Storage (CCS) Institute (www.globalccsinstitute.com) is an independent, not-for-profit company registered under the (Australian) Corporations Act 2001 (Cth). The Institute's mission is to accelerate the development, demonstration and deployment of CCS globally. The Institute was launched with strong and widespread support from governments, corporations, industry bodies and research organizations from key markets around the globe, and has built a diversified membership profile that represents a healthy cross-section of these international stakeholders. The diversity in membership ensures the Institute's endeavors and services provided reflect the varied and evolving nature of the challenges faced by the industry.

Summary of CO_2 Capture

There is an extensive amount of information available supporting the technical feasibility of post-combustion capture, pre-combustion capture, and oxy-combustion capture. For each type of capture, there is information other than from facilities that received any DOE assistance under EPAct05, including facilities that pre-date EPAct05, literature that does not rely on facilities that have received assistance under EPAct05, and foreign facilities. Accordingly, none of the facilities that received EPAct05 assistance must be precluded from EPA's basis due to EPAct05 §§402(i) or 421(a). We also solicit comment on whether there is a sufficient basis for our proposed determination of technical feasibility even without any reference to any facility receiving assistance under EPAct05.

With respect to the limits imposed by IRC §48A(g), if that provision is interpreted narrowly, to be consistent with EPAct05 §402(i) – and putting aside, for present purposes, the other questions of interpretation of §48A, discussed above -- then, as with EPAct05 §402(i), for each type of capture, there is evidence from other facilities and the literature that is not affected by §48A(g), and as a result, none of the facilities that were allocated the §48A tax credit must be precluded from EPA's analysis. If, on the other hand, §48A(g) is interpreted to preclude any reliance on any information from facilities that have been allocated the credit, it is possible that some of this evidence may be precluded from analysis, but, as noted, the remaining evidence is sufficient to support the determination of technical feasibility. We solicit comment on what evidence suffices to demonstrate technical feasibility of CO_2 capture technology.

Technical Feasibility of CO_2 Compression and Transportation

Carbon dioxide has been compressed and transported via pipelines in the U.S. for nearly 40 years[40]. Approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. The majority of this CO_2 has been transported for use in EOR operations. Much of this CO_2 was supplied by facilities other than EGUs, but the compression and transportation technology is the same as the technology used by EGUs. For these reasons, EPA determines that the compression and transportation component of CCS is well-established as technically feasible; and that determination does not depend solely on information from projects receiving assistance under the EPAct05, and remains valid even if facilities allocated the IRC §48A tax credit are excluded (again, putting aside for present purposes the other questions of interpretation of §48A, discussed above).

[40] "Comparing Existing Pipeline Networks with Potential Scale of Future U.S. CO_2 Pipeline Networks", PNNL Report PNNL-17381, February, 2008.

Technical Feasibility of CO_2 Injection and Storage

Scientific understanding, coupled with existing project and regulatory experience (including EOR), research, and analogs (e.g. naturally existing CO_2 sinks, natural gas storage, and acid gas injection), demonstrate that geologic sequestration is a viable long term CO_2 storage option. The first part of this basis is a demonstrated understanding of the fate of CO_2 in the subsurface. Geologic sequestration occurs through a combination of structural and stratigraphic trapping (trapping below a low permeability confining layer), residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the storage formation), solubility trapping (dissolution in the in situ formation fluids), mineral trapping (reaction with the minerals in the storage formation and confining layer to produce carbonate minerals), and preferential adsorption trapping (adsorption onto organic matter in coal and shale).[41,42] These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 is injected.

Project and research experience adds to the confidence in geologic sequestration as a viable CO_2 reduction technology. There are four existing commercial CCS facilities in other countries,[43] and in addition, multiple studies have been completed that have demonstrated geologic sequestration of CO_2 as well as have improved technologies to monitor and verify that the CO_2 remains sequestered.[44] For example, CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for enhanced oil recovery purposes. A study evaluated this project, and estimated that from 1972 to 2005, about 93 million metric tons of CO_2 were injected and about 38 million metric tons of CO_2 were produced, resulting in a geologic CO_2 accumulation of 55 million metric tons of CO_2.[45] This study evaluated the ongoing and potential CO_2 trapping occurring through various mechanisms using modeling and simulations, and collection and analysis of seismic surveys and well logging data. The monitoring at this site confirmed that CO_2 can become trapped in geologic formations. Studies on the permanence of CO_2 storage in geologic sequestration have been conducted internationally as well. For example, the Gorgon Carbon Dioxide Injection Project and Collie-South West CO_2 Geosequestration Hub project in

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[41] Intergovernmental Panel on Climate Change. (2005). *Special Report on Carbon Dioxide Capture and Storage.* Retrieved from http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter5.pdf

[42] Benson, Sally M. and David R. Cole. (2008). *CO_2 Sequestration in Deep Sedimentary Formations*. Elements , Vol. 4, pp. 325–331.

[43] Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

[44] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[45] Han, Weon Shik et al. (2010). *Evaluation of trapping mechanisms in geologic CO_2 sequestration: Case study of SACROC northern platform, a 35-year CO_2 injection site*. American Journal of Science Online April 2010 vol. 310 no. 4 282-324. Retrieved from: http://www.ajsonline.org/content/310/4/282.abstract

Australia have both demonstrated geologic CO_2 trapping mechanisms.[46] As with compression and transportation, much of the technology for injection and sequestration has been used for CO_2 emitted by facilities other than EGUs, but the injection and sequestration technology is the same as the technology used by EGUs.

In addition, CO_2 storage reserves are available throughout the U.S. The Department of Interior's U.S. Geological Survey (USGS) has recently completed a comprehensive evaluation of the technically accessible storage resource for carbon storage for 36 sedimentary basins in the onshore areas and State waters of the United States.[47] The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 storage potential across the United States. For comparison, this amount is 500 times the 2011 annual U.S. energy-related CO_2 emissions of 5.5 Gigatons (Gt).[48] According to the USGS assessment, nearly every state in the U.S. has or is in close proximity to formations with carbon storage potential, including vast areas offshore.

Geologic storage options also include use of CO_2 in EOR, which is the injection of fluids into a reservoir to increase oil production efficiency. EOR is typically conducted at a reservoir after production yields have decreased from primary production. Fluids commonly used for EOR include brine, fresh water, steam, nitrogen, alkali solutions, surfactant solutions, polymer solutions, and CO_2. EOR using CO_2, sometimes referred to as "CO_2 flooding" or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil and make it available for recovery. A crude oil and CO_2 mixture is produced, and sent to a separator where the crude oil is separated from the gaseous hydrocarbons and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, recompressed, and re-injected into the oil or natural gas reservoir to further enhance recovery.

CO_2-EOR has been successfully used at many production fields throughout the U.S. to increase oil recovery. The oil and natural gas industry in the United States has over 40 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for successful deployment of CCS.

Monitoring CO_2 at EOR sites can be an important part of the petroleum reservoir

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[46] Sewell, Margaret, Frank Smith and Dominique Van Gent. Western Australia Greenhouse Gas Capture and Storage: A tale of two projects. (2012) Australian Department of Resources, Energy and Tourism and Western Australia Government of Western Australia. Retrieved from http://cdn.globalccsinstitute.com/sites/default/files/publications/39961/ccsinwareport-opt.pdf

[47] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources – Results: U.S. Geological Survey Circular 1386, 41 p., http://pubs.usgs.gov/fs/2013/1386/.

[48] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources – Summary: U.S. Geological Survey Factsheet 2013-3020, 6p.http://pubs.usgs.gov/fs/2013/3020/.

management system to ensure the CO_2 is effectively sweeping the oil zone, and can be supplemented by techniques designed to detect CO_2 leakage. Recently, many studies have been conducted to better understand the fate of injected CO_2 at well-established, operational EOR sites. A large number of methods are available to monitor surface and subsurface leakage at EOR sites. Some recent studies are presented below.

At the SACROC field in the Permian Basin, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers. At the time of the study (2011), the SACROC field had injected 175 million metric tons of CO_2 over 37 years. No evidence of leakage was detected.[49]

An extensive CO_2 leakage monitoring program was conducted by a third party (International Energy Agency Greenhouse Gas Programme) for 10 years at the Weyburn oil field in Saskatchewan, during which time over 16 million tonnes of CO_2 have been stored. A comprehensive analysis of surface and subsurface monitoring methods was conducted and resulted in a best practices manual for CO_2 monitoring at EOR sites.[50]

The Texas Bureau of Economic Geology has also been testing a wide range of surface and subsurface monitoring tools and approaches to document storage efficiency and storage permanence at a CO_2 EOR site in Mississippi.[51] The Cranfield Field, under CO_2 flood by Denbury Onshore LLC, is a depleted oil and gas reservoir that injected greater than 1.2 million tons/year during the tests. The preliminary findings demonstrate the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage.

The Department of Energy has conducted numerous evaluations of CO_2 monitoring techniques at EOR pilot sites throughout the U.S. as part of the Regional Sequestration Partnership Phase II and III programs and have created a 'Best Practices' guide for monitoring, verification, and accounting of CO_2 stored in deep geologic formations from that experience.[52]

As with CO_2 compression and transportation, EPA determines that the injection and

[49] K.D. Romanak, R.C. Smyth, C. Yang, S.D. Hovorka, M. Rearick, J. Lu. (2011). *Sensitivity of groundwater systems to CO2: Application of a site-specific analysis of carbonate monitoring parameters at the SACROC CO_2-enhanced oil field*. GCCC Digital Publication Series #12-01. Retrieved from http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=190

[50] Geoscience Publishing. (2012). *Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project*. Brian Hitchon (Ed.),

[51] Hovorka, S.D., et al. (2011). *Monitoring a large volume CO_2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA*: Energy Procedia, v. 4, Proceedings of the 10th International Conference on Greenhouse Gas Control Technologies GHGT10, September 19-23, 2010, Amsterdam, The Netherlands, p. 3478-3485. GCCC Digital Publication #11-16. Retrieved from http://www.sciencedirect.com/science/article/pii/S1876610211004711

[52] DOE/NETL. (2012). *Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update*. DOE/NETL-2012/1568. Retrieved from http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf.

storage component of CCS is well-established as technically feasible; and that determination does not depend solely on information from projects receiving assistance under the EPAct05, and remains valid even if facilities allocated the IRC §48A tax credit are excluded (again, putting aside for present purposes the other questions of interpretation of §48A, discussed above).

Costs

As noted in the preamble for the 2014 Proposal and summarized above, according to the D.C. Circuit case law, control costs are treated as acceptable as long as they are reasonable (which, as noted above, is EPA's shorthand for the various formulations the Court has used, including, among others, that costs cannot be "excessive" or "unreasonable")[53]. .

In determining the amount of costs for partial CCS, the EPA relied on DOE/NETL "Cost and Performance" reports[54]. DOE/NETL established the costs of new coal-fired electric power plants with partial CCS on a "next-of-a-kind" basis, so that those new plants would not bear the higher, "first-of-a-kind" costs. Those next-of-a-kind cost estimates remain valid, notwithstanding any limitations imposed by any of the provisions of EPAct05.[55] In this rulemaking, EPA is authorized to base cost estimates on that premise – that new plants will be the next-of-a-kind – because that is factually true, and there is no reasonable reading of IRC §48(g) or any of the other EPAct05 provisions that would mandate that new plants be treated as having first-of-a-kind costs. In this context, nothing in IRC §48A(g) or the other relevant EPAct provisions precludes the recognition that new plants follow ones currently under construction or in the planning stages -- such as Kemper, TCEP, and HECA – and therefore that new plants must be treated as next-of-a-kind. To require that new plants be treated as first-of-a-kind on grounds that, for example, under IRC §48A(g), Kemper, TCEP, and HECA, cannot form part of the basis for the cost analysis because they have been allocated the §48A credit,[56] would be contrary to the clear facts. In any event, as discussed above, even without referring to any plant that has been allocated the credit, other plants have sufficiently demonstrated the technology so that, on those grounds, too, new plants must be considered next-of-a-kind.

As discussed in the 2014 Proposal, the EPA examined costs of new fossil fueled power

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[53] 79 FR 1464

[54] The ''Cost and Performance Baseline'' reports are a series of reports by DOE/NETL that establish estimates for the cost and performance of combustion- and gasification-based power plants— all with and without CO_2 capture and storage. Available at http://netl.doe.gov/research/energy-analysis/energy-baseline-studies

[55] It should also be noted that the NETL studies did not take into account the possibility that a coal-fired electric power plant with partial CCS may receive assistance under EPAct05, including the IRC §48A tax credit. By the same token, EPA, in the 2014 Proposal, also explicitly noted that the estimated costs "do not include the impact of subsidies that may potentially be available to developers of new projects that include CCS."

[56] Here again, for convenience, we will put aside for the moment the other issues of interpretation of IRC §48A described above.

generation options – including for new NGCC units, for new supercritical and IGCC units with no CCS, and for those units with partial capture CCS installed such that their emissions would meet the proposed 1,100 lb CO_2/MWh standard. We determined that, while new coal-fired generation that includes partial CCS is more expensive than either new NGCC generation or new coal-fired generation without CCS, it is competitive with new nuclear power, which, besides natural gas combustion turbines, is the principal other option often considered for providing new base load power with a lower carbon footprint. It is also competitive with biomass-fired generation, which is another generation technology often considered for low carbon base load power. Because the costs are comparable, the EPA determined that, at the proposed emission limitation of 1,100 lb CO_2/MWh, the cost of new coal-fired generation that includes partial CCS is not unreasonable.[57]

It should be noted that even without comparison to such other electricity generation, the costs are acceptable because (i) they meet the D.C. Circuit's standards for acceptable costs (e.g., as noted above, not excessive or unreasonable), and (ii) EPA exercises its authority in determining the best system of emission reduction adequately demonstrated to, in this case, give greater weight to the need to promote CCS technology, notwithstanding its higher costs.

Amount of Emission Reductions and Promotion of Technology

Although this TSD and the accompanying NODA focus on the technical feasibility and cost components of the BSER determination – because it is those components that are primarily affected by the EPAct05 provisions – we reiterate our views in the 2014 Proposal that the other components of that determination support identifying partial CCS as the BSER. As discussed in the 2014 Proposal, EPA has discretion in weighing the various components, and for this rulemaking, an important component is the amount of reductions achieved. For post combustion capture, all of the projects cited above are designed to capture 90% or more of the CO_2 from the flue gas treated. The projects currently operating are capturing from approximately 200 tons per day to 800 tons per day. Projects cited above under development demonstrate the industries' belief that the technology can be designed and operated at larger scales necessary to capture 50+% of the CO_2 from a 500 MW coal-fired power plant.

Another particularly important component for this rulemaking is to advance technology. Identifying partial CCS as the BSER does so by promoting the utilization of CCS. This is because any new fossil fuel-fired utility boiler or IGCC unit will need to install partial capture CCS in order to meet the emission standard. Particularly because the technology is relatively new, additional utilization is expected to result in improvements in the performance technology and in cost reductions. Moreover, identifying partial capture CCS as the BSER will encourage

[57] 79 FR 1477

continued research and development efforts, such as those sponsored by the DOE/NETL. In contrast, not identifying partial CCS as the BSER could potentially impede further utilization and development of CCS. It is important to promote deployment and further development of CCS technologies because they are the only technologies that are currently available or are expected to be available in the foreseeable future that can make meaningful reductions in CO_2 emissions from fossil fuel-fired utility boilers and IGCC units.

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Appendix
Summary of Key Projects Considered and EPA's Understanding of Use of Financial Incentives under EPAct05

Project Name	Location	Overview	Funding under EPAct05?[58]	Allocation of tax credit under IRC §48A?
Post Combustion Capture				
Searless Valley Mineral Soda Ash	Trona, CA	800 tons per day, began operating in 1976	No	No
AES - Warrior Run	Cumberland, MD	200 tons per day, began operating in 2000	No	No
AES - Shady Point	Panama, OK	800 tons per day, began operating in 2001	No	No
AEP Mountaineer	New Haven, WV	7,000 tons/month, began operating in 2009 (operated for 12-18 months)	Yes	No
Southern Company, Plant Barry	Mobile, AL	500 tons/day, began operating in 2011	Yes	No
SaskPower, Boundary Dam	Estevan, SK, Canada	1,000,000 ton/year, scheduled to come on line in April 2014	No	No
NRG (Petra Nova) – WA Parish Plant	Houston, TX	1,400,000 tons/year, scheduled start date, 2016	Yes	No
Pre-combustion Capture				
Dakota Gasification Company – Great Plains Synfuels	Beulah, ND	Over 2,000,000 tons/year on average since 2000.	No	No
Coffeyville Gasification Plant	Coffeyville, KS	Separated about 850,000 tons of CO_2 per year. Until 2013, small amounts were used for	Yes	No

[58] This category includes allocation of the tax credit under IRC §48B.

		fertilizer production and most was vented to the air. In 2013, began capturing an additional 650,000 tons/year for EOR		
Southern Company – Kemper County Energy Facility	Kemper County, MS	Scheduled to commence operation in late 2014. Deigned to capture 65% of CO_2, approximately 3,500,000 tons/year CO_2	Yes	Yes
Summit Power's Texas Clean Energy Project	Odessa, TX	In advanced stages of financing (have contracts for electricity, CO_2 and fertilizer production). Designed to capture. Designed to capture 90% of CO_2 (approximately 3,000,000 tons/year)	Yes	Yes
Hydrogen Energy California	Kern County, CA	In advanced stages of project development Designed to capture 90% of CO_2 (approximately 3,000,000 tons/year	Yes	Yes