October 31, 2018

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EPA Docket Center
U.S. EPA, Mail Code 28221T
1200 Pennsylvania Ave, NW
Washington DC 20460
Attn: Docket No. ID EPA-HQ-OAR-2017-0355

Re: Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revision to New Source Review Program, 83 Fed. Reg. 44,746 (Aug. 31, 2018).

Clean Air Task Force (CATF) and Natural Resources Defense Council (NRDC) respectfully submit these comments on the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, or Affordable Clean Energy rule ("ACE" or "Proposal"). These comments are directly responsive to the U.S. Environmental Protection Agency's ("EPA" or "Agency") request that "if there is any new information regarding the availability, applicability, costs, or technical feasibility of CCS technologies, commenters are encouraged to provide that information to EPA (Comment C-12)." 83 Fed. Reg. at 44,762.

Founded in 1996, CATF seeks to help safeguard against the worst impacts of climate change by working to catalyze the rapid global development and deployment of low carbon energy and other climate-protecting technologies, through research and analysis and public advocacy leadership.

NRDC is a national nonprofit environmental organization representing more than three million members and online activists. NRDC uses law, science, and the support of its members to ensure a safe and healthy environment for all living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

These comments incorporate and supplement the Joint Comments[1] and individual comments submitted by CATF and NRDC to this docket today. The focus of these comments is EPA's treatment of carbon capture and sequestration (CCS) in the Proposal.

I. Introduction

CCS is adequately demonstrated, cost reasonable and likely important to staving off the worst impacts of catastrophic climate change. EPA fails to overcome the extensive record on CCS built under the Clean Power Plan or to build a record of support for its determination that CCS is not part of the best system of emission reduction (BSER). In light of the availability of CCS at reasonable cost to achieve emission reductions significantly greater than the proposed heat rate improvements, the Proposal is arbitrary, capricious and unlawful.

II. CCS far exceeds the statutory requirements for the BSER and must be considered in the Proposal.

Clean Air Act requires EPA to identify the *best*, adequately demonstrated system of emission reduction considering costs and health, environmental and energy impacts.[2] "[T]he amount of air pollution [is] a relevant factor to be weighed when determining the optimal standard."[3] In the Proposal, EPA seems to be questioning whether "section 111(d) may be used to project technological advances,"[4] but it settled law that the section is technology-forcing and "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present."[5]

EPA's standards have been upheld on the basis of 1) "literature review and operation of one plant in the U.S;"[6] 2) "various test programs;"[7] 3) "pilot plant technology;"[8] and 4) "testimony from experts and vendors."[9] EPA may also base standards upon "the reasonable extrapolation of a technology's performance in other industries."[10] EPA's standards are also reasonable where "the combination of controls is novel" and each of the "components have been tested and used."[11] As we describe in detail below, CCS has well exceeded this demonstration.

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[1] *See* Joint Environmental Comments on Framework Regulations; Joint Environmental Comments on Regulatory Impact Analysis; Joint Environmental Comments on BSER Issues; Joint Environmental Comments on NSR Issues; Joint Environmental Comments on Climate Science; CATF & NRDC Comments on Biomass.

[2] 42 U.S.C. § 7411(a)(1).

[3] *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

[4] 83 Fed. Reg. at 44,761-62.

[5] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

[6] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, at 434 (D.C. Cir. 1973).

[7] *Cf. Nat'l Petrochemical & Refiners Ass'n v. EPA*, 287 F.3d 1130, 1137 (D.C. Cir. 2002) (upholding CAA section 202(a)(3) standards for new motor vehicles, which have a similar basis as section 111 standards).

[8] *Cf. Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1061 (3rd Cir. 1975) (upholding Clean Water Act standards and guidelines, which are based on the best practicable technology currently available); *cf. FMC Corp. v. Train*, 539 F.2d 973, 983-83 (4th Cir. 1976) (upholding EPA's decision to set Clean Water Act guidelines based on data from a single pilot plant).

[9] *Portland Cement Ass'n,* 486 F.2d at 402.

[10] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1978).

[11] *Cf. Sur Contra la Contaminacion v. EPA*, 202 F.3d 443, 448 (1st Cir. 2000) (upholding CAA section 145 best available control technology determination).

Costs are reasonable where "[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the…standards,"[12] and were not "exorbitant."[13] As EPA previously determined, costs of CCS are in line with other low- or zero-emitting baseload technology, such as nuclear.[14] Moreover, the availability of the 45Q tax credit for sequestered carbon and the availability of enhanced oil recovery proceeds reduce costs even further. As EPA explains in the Proposal the "costs attributed to CO_2 emission reductions…is the net cost" once things like fuel savings, proceeds and tax credits are taken into account.[15] Additionally, as described below, costs are expected to follow the typical declining trajectory as more projects are developed and built.

It is unavoidable that uniform national standards will impose greater burdens on some plants than others, but this does not undermine the reasonableness of the standards.[16] Here, however, EPA failed to provide a national emission limit as required. *See* Joint Environmental Comments on BSER Issues. While that omission renders the Proposal unlawful, the proposed scheme allows states to take into consideration the characteristics of individual plants but arbitrarily fails to include CCS in the list of "candidate technologies" that can be implemented on a "source-specific" basis.

III. CCS must be included in the BSER for existing power plants.

In three short paragraphs, EPA dispenses with one of the most promising technologies for significantly reducing CO_2 emissions from fossil fuel-fired power plants. The Agency "entirely failed to consider"[17] or even cite any studies, projects, or reports before hastily rejecting CCS as part of the BSER. "Th[is] type of vaporous record will not do—the Administrative Procedure Act requires reasoned decisionmaking grounded in actual evidence."[18] This failure to develop any record supporting the decision renders the Proposal arbitrary, capricious and unlawful.[19]

EPA's reason for rejecting CCS is based on a mischaracterization of the Clean Power Plan record. The Agency claims that it previously found that CCS should not be part of the BSER because it is "significantly more expensive than alternative options for reducing emissions and may not be a viable option for many individual facilities."[20] EPA actually found that CCS is "more expensive" as compared to the Clean Power Plan approach, which leveraged the lower cost options available due to the integrated nature of the electric system.[21] In fact, EPA found that CCS is "technically feasible and within price ranges that [are] cost effective in the context of other GHG rules."[22] EPA went on to note that CCS may be viable option at some individual facilities resulting in emission reduction

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[12] *Portland Cement*, 486 F.2d at 508.
[13] *Lignite Energy Council*, 198 F.3d at 933.
[14] 80 Fed. Reg. at 64,562-63, tbl. 8.
[15] 83 Fed. Reg. at 44,759.
[16] *See Weyerhouser Co. v. Council*, 590 F.2d 1011, 1054 (D.C. Cir. 1978) (upholding EPA effluent limitations that were more difficult for some mills to meet).
[17] *Motor Vehicles Mfrs. Ass'n v. State Farm*, 463 U.S. 29, 43 (1983) (internal citations omitted).
[18] *Flyers Rights Educ. Fund v. FAA*, 864 F.3d 738, 741 (D.C. Cir. 2017).
[19] 5 U.S.C. § 706(2)(A); 42 U.S.C. § 7607(d)(9).
[20] 83 Fed. Reg. at 44,761.
[21] 80 Fed. Reg. at 64,727-28.
[22] *Id.* at 64,727.

that could be significant, noting that multiple existing facilities have already been retrofit with CCS and costs are expected to decline.[23] But ultimately concludes "as a practical matter, were the EPA to include co-firing and CCS in the BSER and promulgate performance standards accordingly, few EGUs would likely comply with their emission standards through co-firing and CCS; rather, the EGUs would rely on the lower cost options of substituting lower- or zero-emitting generation or, as a related matter, reducing generation" – which is what EPA chose as the BSER in the Clean Power Plan.[24]

Now that EPA has – unreasonably – taken this lower cost option off the table it must perform its own "complex balancing"[25] of the section 111 factors to determine the *best* system. Instead, EPA relies on a mischaracterization of the previous record and fails to build a record at all supporting its decision. Further, EPA fails to provide any support for its claim that CCS may not be viable for some individual plants or square this concern with its Proposal, which allows states to determine standards of performance on a case-by-case basis, tailored to the characteristics of particular power plants.

Even though in the Clean Power Plan, EPA ultimately determined that the generation-shifting approach was superior to a BSER based on CCS, it first undertook an extensive review and built up a substantial record on CCS, its achievability, costs, emission reduction potential, and the regulatory framework for CCS.[26] EPA must "provide a more detailed justification than would suffice for a new policy…when, for example, its new policy rests upon factual findings that contradict those which underlay its prior policy… It would be arbitrary and capricious to ignore such matters."[27] "An agency cannot simply disregard contrary or inconvenient factual determinations that it made in the past."[28]

EPA cannot ignore the record underlying the Clean Power Plan, which described that various carbon capture options for existing power plants, CO_2 pipeline infrastructure, and geologic sequestration is "technically feasible and available throughout most of the United States."[29] EPA recognized that "[c]arbon capture technology has been successfully applied since 1930 on several smaller scale industrial facilities and more recently in a number of demonstration phase projects worldwide for power sector applications."[30] EPA then reviews the commercial-scale power plant projects at Boundary Dam and PetraNova.[31] EPA concluded geologic sequestration is available in

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23 *Id.*
24 *Id.* at 64,728.
25 *Am. Elec. Power Co. v. Connecticut*, 564 U.S. 410, 427 (2011).
26 *See generally* 79 Fed. Reg. at 34,876; EPA, Technical Support Document, *GHG Abatement Measures*, ch. 7 (June 2014); 80 Fed. Reg. at 64,756, 64,883-84; EPA, *Regulatory Impact Analysis for the Clean Power Plan Final Rule*, at 2-29 – 2-39 (Aug. 2015) [hereinafter "CPP RIA"]; EPA, *Basis for Denial of Petitions to Reconsider and Petitions to Stay the CAA section 111(d) Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units*, at App. 3, *Non-BSER CPP Flexibilities*, at 3-10 (Jan. 2017) [hereinafter "Reconsideration Denial"].
27 *FCC v. Fox Television Stations*, 566 U.S. 502, 515-16 (2009) (internal citation omitted).
28 *Id.* at 537 (Kennedy, J., concurring).
29 EPA, Technical Support Document, *GHG Abatement Measures*, ch. 7 (June 2014) [hereinafter "Abatement TSD"]; CPP RIA at 2-29 – 2-39.
30 CPP RIA at 2-31.
31 *Id.*

deep saline formations and via enhanced oil recovery (EOR) and that the experience of CO_2-EOR "provides a strong foundation for the injection and monitoring technologies that will be needed for successful deployment of CCS."[32]

EPA updated its record on emission reduction "opportunities available within a plant including…carbon capture and storage" last year.[33] The Agency reaffirmed that CCS has been "successfully implemented at multiple projects around the world during the past decades …and can be retrofitted on an existing plant."[34] EPA provided updates on the two existing coal-fired power plant CCS retrofits and the bioethanol CCS project at Illinois Basin Decatur Capture and Storage Project.[35] EPA incorporated into the record two amicus briefs which "explain that carbon capture technologies and carbon storage are mature and viable, as well as explain that carbon capture technology can be expected to continue to improve and become less expensive as it is deployed more."[36] EPA also explained that there are several CCS projects that would have been installed but for the lack of a regulatory driver and that there is significant potential for CCS across the existing coal-fired fleet.[37] EPA also updated the availability of sequestration opportunities and available pipelines, concluding that retrofit CCS is broadly available across the United States.[38]

EPA fails to engage, let alone overcome, the substantial Clean Power Plan record on CCS. Because the Agency – unreasonably – removes the lowest cost, building block approach from consideration, it must start anew and engage in a thorough review of all available measures, including CCS, and provide "reasoned analysis to cogently explain why its recommended measures satisfied the [statute's] requirements."[39]

EPA fails to consider the factors relevant to a section 111 rulemaking – best, technology-forcing, and the amount of emission reductions – and instead relies wholly on a mischaracterization of the Clean Power Plan's analysis of CCS. These failures render the Proposals record woefully incomplete and the rulemaking arbitrary, capricious and unlawful.

IV. As summarized in the CPP record, all components of CCS are adequately demonstrated.

CCS is composed of three separate technologies: 1) carbon capture, 2) transportation, and 3) injection and storage of CO_2 deep underground. These technologies are available, demonstrated, and have been in wide commercial use for decades. *See* Appendix B for extensive technical discussion of all components of CCS.

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[32] CPP RIA at 2-37 – 2-38; Abatement Measures TSD at 7-4.
[33] Reconsideration Denial at App. 3, *Non-BSER CPP Flexibilities*, at 3-10.
[34] *Id.* at 3
[35] *Id.* at 4-5
[36] *Id.* at 5 (citing Br. for *Amicus Curiae* Carbon Capture and Storage Scientists, Doc No. 1652097, *North Dakota v. EPA*, No. 15-1381 (D.C. Cir. Dec. 21, 2016); and Br. for *Amicus Curiae* Technology Innovation Experts, Doc No. 1652263, *North Dakota v. EPA,* No. 15-1381 (D.C. Cir. Dec. 21, 2016)).
[37] *Id.* at 5.
[38] *Id.* at 5-10.
[39] *NRDC v. Daley*, 209 F.3d 747, 755-56 (D.C. Cir. 2000).

Since the 1930's, carbon capture equipment has been used commercially to purify natural gas, hydrogen, and other gas streams found in industrial settings.[40] Since that time, the technology has evolved and grown. Every year, China captures over 270 million tonnes of high-purity CO_2 from plants that process coal into fertilizers, methanol, substitute natural gas, and a variety of industrial chemicals.[41] In the United States, over 26 million tons of CO_2 is captured from natural gas processing plants, refineries, and fertilizer plants and sold for EOR.[42] Since the 1970s, over 850 million tonnes of CO_2 have been injected underground in the United States for EOR.[43] Another approximately 12.5 million tonnes/year in United States supplies the food industry, beverage carbonation and other specialty applications.[44]

A mature network of over 4,500 miles of pipelines brings CO_2 to EOR fields in the United States,[45] while trucks and rail cars operated by specialty chemical companies transport smaller volumes to meet the needs of the food industry and other chemical uses.

The United States has a strong and mature regulatory structure in place to support these commercial activities. The transport of CO_2 through pipelines is jointly regulated by states and the federal government. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration oversees operation and construction, including design specifications.[46] EPA regulates injection of CO_2 through the Safe Drinking Water Act's Underground Injection Control Program and the Clean Air Act's Greenhouse Gas Reporting Program. Many states, particularly with active oil and gas industries, have their own set of regulations that govern the reporting of CO_2 injection for state tax and safety purposes. These include California, Montana, North Dakota, Wyoming, Kansas, Oklahoma, Texas, Louisiana and Mississippi.[47] IRS guidelines and requirements govern tax credits.

Now the experience of CO_2 capture, transport and storage gained in industrial plants over the last 50 to 80 years is migrating to the power sector as part of efforts to address climate change. Canada, for example, requires coal plants to either close or install CCS by 2030.[48] New York state has adopted

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[40] Anthony Armpriester, Petra Nova Parish Holdings LLC, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project*, at 10 (2017), https://www.osti.gov/scitech/biblio/1344080-parish-post-combustion-co2-capture-sequestration-project-final-public-design-report.

[41] Zhong Zheng, Princeton University China Energy Group, *CO_2 Storage: Large-scale Low-cost Demonstration Opportunities in China* (2012), http://www.princeton.edu/puceg/perspective/ccs_%20in_china.html.

[42] Timothy C. Grant, *An Overview of the CO_2 Pipeline Infrastructure*, at 3 (Oct. 18, 2018) (Attach. A).

[43] Bruce Hill, Susan Hovorka & Steve Melzer, *Geologic carbon storage through enhanced oil recovery*, 37 Energy Procedia 6808, 6811 (2013), https://ac.els-cdn.com/S1876610213008576/1-s2.0-S1876610213008576-main.pdf?_tid=983571f7-bab0-4cce-917c-42529f537266&acdnat=1540136852_e133d0666a3fd9606bcb83e497fdd325.

[44] Bala Suresh, *Global Market for Carbon Dioxide*, at 26 (Feb. 2017) (Attach. B).

[45] Matthew Wallace, Lessly Goudarzi, Kara Callahan & Robert Wallace, Energy Sector Planning and Analysis, *A review of the CO2 pipeline infrastructure in the U.S.*, at 1 (2015), https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

[46] *Id.*

[47] *See* C2ES, Map, "Rules for CO2 Injection," https://www.c2es.org/document/rules-co2-injection/ (last accessed Oct. 24, 2018) (describing state legislation specifying requirements applicable to CO_2 injection for EOR and geologic storage).

[48] Sonal Patel, *Canada to Phase Out Coal Generation by 2030, Stricter Power Plant Rules on the Horizon*, POWER (Nov. 21, 2016), https://www.powermag.com/canada-to-phase-out-coal-generation-by-2030-stricter-power-plant-rules-on-horizon/?printmode=.

regulations requiring existing coal plants to either retrofit with CCS or cease operations by 2021.[49] Technical Appendix B describes the industrial and other demonstration projects whose experience is directly transferable to establishing regulations based on CCS in the power sector. Specific coal and gas CCS projects are highlighted below.

a. Real-world project experience shows that carbon capture is adequately demonstrated for both coal and gas power plant application.

EPA's standards have been upheld on the basis on test programs, pilot plant technology, operation of the measure at one plant, and the operation of similar measures applied in different industries. In addition to the projects described in Appendix B, CCS has been installed on multiple fossil fuel-fired power plants as described below. These projects demonstrate that CCS is adequately demonstrated, and the costs are certainly not exorbitant - these projects were undertaken without any regulatory requirement.

W. A. Parish Plant, Thompsons Texas:

Petra Nova began capturing CO_2 on January 10, 2017 after retrofitting NRG Energy's W.A. Parish coal-fired power plant southwest of Houston, in Thompsons Texas.[50] The project was built on time and on budget.[51] A 240 MWe slipstream uses Mitsubishi Heavy Industries (MHI) capture technology to remove 90% of the CO_2 or about 1.4 MMtpa.[52] The CO_2 is transported by an 82-mile pipeline to the Hilcorp West Ranch Oil Field in Jackson County Texas for use in EOR where initial estimates projected a boost oil production between 500 and 15,000 barrels of oil per day[53] and is currently producing over 5,000 barrels per day.[54]

The W.A. Parish project includes a number of innovative technical advances. Specifically, the project's use of amine technology specifically designed to capture CO_2 from low-pressure coal plant flue gas streams that have been scrubbed of virtually all ash, sulfur and nitrogen.[55] The primary

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[49] NYS Register, at 5 (May 16, 2018). The standards require existing power plants to meet an emissions limit of either 1,800 lbs./MW-hr gross electrical output or 180 lbs./MMBtu of input by December 31, 2020, on a 12-month rolling average or annual CO_2 emission basis.

[50] National Energy Technology Laboratory, U.S. Department of Energy, *Recovery Act: Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project*, https://www.netl.doe.gov/research/coal/project-information/fe0003311.

[51] David Greeson, *Carbon Capture with new 45Q* (2018), https://www.naruc.org/default/assets/File/CCS45Q_041018.pdf.

[52] National Energy Technology Laboratory, *supra* note 50.

[53] *Id.*

[54] Greeson, *supra* note 51.

[55] *See generally* NRG, "Petra Nova," https://www.nrg.com/case-studies/petra-nova.html; NARUC DOE/NARUC Carbon Capture, Storage & Utilization Partnership Webinar Summary "Petra Nova and the Future of Carbon Capture" (Mar. 23, 2017), https://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-DOE-341-082312.pdf; EIA, "Petra Nova is one of two carbon capture and sequestration power plants in the world," (Oct. 31, 2017), https://www.eia.gov/todayinenergy/detail.php?id=33552; NETL, "Recovery Act: Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project," https://www.netl.doe.gov/research/coal/project-information/fe0003311; Sonal Patel, Capturing Carbon and Seizing Innovation: Petra Nova is POWER's Plant of the

amine solvent ingredient used in the process is readily available worldwide and inexpensive, and the process is offered commercially with performance warranties.[56] The solvents have relatively low energy consumption properties and, in addition, the industry is developing more advanced solvents for even better performance.[57] Innovations in process equipment performance for this project, such as absorber intercooling and lean solution vapor compression have the potential to reduce the energy requirements of these systems by as much as 20 percent.[58] Additionally, efficiency improvements in the supporting balance of plant processes such as process steam generation and CO_2 compression will also reduce energy requirements. These advances are anticipated to lower carbon capture costs and increase system flexibility and efficiency.

Southern Company Plant Barry Project, Mobile, Alabama:

In 2012 Alabama Power's Plant Barry became a fully integrated CCS project utilizing CO_2 from a coal-fired power plant and demonstrated the availability of fully integrated carbon capture and geologic storage technology in the U.S.[59] The project captured and stored 150,000 metric tons per year (tpa) CO_2 before ending in December 2015.[60] The Southern Company project was supported by the U.S. Department of Energy (DOE) and partners Denbury Resources, the Southeast Regional Carbon Sequestration Partnership (SECARB), Electric Power Research Institute (EPRI) and Advanced Resources, Inc.[61] CO_2 was captured at Plant Barry from a 25 MW emissions slip stream with post-combustion, MHI amine technology and transported 12 miles by pipeline to Denbury Resources' Citronelle oilfield where injection of CO_2 captured from Plant Barry began in August 2012 into the Paluxy sandstone, a saline brine-bearing formation.[62] The monitoring, verification, and accounting program was led by SECARB, LBNL and EPRI and has resulted in the development of an innovative fiber optic Modular Downhole Monitoring system (MBM) that can monitor in-zone pressure, temperature and CO_2 distribution.[63]

Year, Power (Aug. 1, 2017), https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/; Massachusetts Institute of Technology, *W.A. Parish Fact Sheet*, https://sequestration.mit.edu/tools/projects/wa_parish.html.

[56] *Id.*

[57] *Id.*

[58] Timothy Gardener, *U.S. utilities balk at expanded carbon-capture subsidy*, Reuters (Aug. 2, 2018) https://www.reuters.com/article/us-usa-carbon-storage-analysis/u-s-utilities-balk-at-expanded-carbon-capture-subsidy-idUSKBN1KN1HM ("David Knox, an NRG spokesman, said operating Petra Nova is showing the firm ways to cut costs for the next generation of technology, such as using smaller towers with less steel. 'We feel you can build a second one for maybe up to 20 percent cheaper,' Knox said").

[59] Office of Fossil Energy, U.S. Department of Energy, *DOE-Sponsored Project Begins Demonstrating CCUS Technology in Alabama* (Aug. 22, 2012), http://energy.gov/fe/articles/doe-sponsored-project-begins-demonstrating-ccus-technology. *See generally* George Koperna *et al.*, *The SECARB Anthropogenic Test: A U.S. Integrated CO2 Capture, Transportation and Storage Test*, 1 Int'l J. of Clean Coal and Energy 13 (2012), http://www.scirp.org/journal/PaperInformation.aspx?paperID=19454#.U07ZJOZdWQw.

[60] Global CCS Institute, *Plant Barry & Citronelle Integrated Project* (2017), https://www.globalccsinstitute.com/projects/plant-barry.

[61] *Id.*

[62] *Id.*

[63] Global CCS Institute, *Global Status of CCS: 2013* at 132 (2013); Thomas M. Daley *et al.*, *Advanced Monitoring Techniques and their application at the SECARB phase III CO2 storage site near Citronelle Alabama* (2013), http://www3.aiche.org/proceedings/Abstract.aspx?PaperID=345411.

The successful operational demonstration at Plant Barry was an important consideration in Petra Nova's decision to adopt the MHI technology for the W.A. Parish plant.[64] In a report to DOE, Petra Nova noted that the Plant Barry demonstration showed that the MHI technology, was "able to successfully demonstrate key features of the technology including the stability of the KS-1™ solvent, amine emissions reduction, heat integration, and automatic load following control."[65] The development of the MHI system is the culmination of efforts that began 25 years ago. In the 1990s, MHI partnered with Kansai Electric Power Company (KEPCO) to develop and test solvents at KEPCO's Nanko power plant. From lab tests on over 200 solvents, about 20 were evaluated at the Nanko plant. Subsequently, MHI developed commercial systems of the capture technology that was used at 11 commercial capture projects, primarily in natural gas flue settings, that ranged in size from 300 to 500 tons per day. In 2006, MHI applied the technology to a 10 MW slip stream at Japan's Matsushima 500 MW commercial coal-fired power plant. The long-term tests at this facility verified the impact of coal-fired flue gas impurities on the process and allowed MHI to develop solutions to these challenges.[66]

Boundary Dam, Saskatchewan, Canada:

The SaskPower Boundary Dam project was the first large-scale, post-combustion capture project added to a coal plant. It captures CO_2 from a 110 MW electric generating unit (EGU) (Unit 3 at Boundary Dam Power Station).[67] It began commercial operation on October 2, 2014.[68] The project captures up to 90 percent of the CO_2 from the 110 MW unit or approximately 0.8 to 1 Mtpa.[69] The CO_2 captured from Unit 3 is sent to two locations. Most of the CO_2 is transported via a 60-mile pipeline to the Whitecap Resources' Weyburn Oil Unit where it is injected 1.4 km below the ground surface. CO_2 from the project is also sent to a nearby deep saline formation as part of the Saskatchewan Aquistore project where it is injected 3.2 km below ground.[70]

The Shell Cansolv capture unit's operation experienced some initial difficulties early on due to the low-rank coal creating fly ash and other contaminant challenges for the solvent, causing its premature solvent degradation. Numerous generic equipment problems unrelated to the CCS

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[64] Armpriester, *supra* note 40, at 6.
[65] *Id.* at 11.
[66] *Id.* at 10.
[67] *See generally* SaskPower, "Boundary Dam Carbon Capture Project," https://www.saskpower.com/our-power-future/infrastructure-projects/carbon-capture-and-storage/boundary-dam-carbon-capture-project; Mike Monea, SaskPower, Powerpoint "SaskPower CCS," https://unfccc.int/sites/default/files/01_saskatchewan_environment_micheal_monea.pdf; Karl Stephenne, Shell Cansolv, Start-up of the World's First Commercial Post-Combustion Coal Fired CCS Project: Contribution of Shell Cansolv to SaskPower Boundary Dam ICCS Project, 63 Energy Procedia 6106 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214024576; IEAGHG, Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station, (Aug. 2015), https://ccsknowledge.com/resources/ieaghg-integrated-ccs-project-bd3.
[68] *Id.*
[69] *Id.*
[70] *Id.*

portion of the project caused periods of downtime. But despite these challenges, the facility still captured 800,000 tonnes of CO_2 between November 2015 to October 2016. [71]

Between October 2015 and August 2017, SaskPower implemented major improvements to the process to address solvent degradation, replacing certain piping and equipment sections made with carbon steel with stainless steel, revamping temperature and process controls to meet design specifications and to minimize fouling, and other changes aimed at improving safety and maintenance. These improvements were successful, and by October 2017, the plant had achieved design capacity and the ability to maintain 85% operational availability for on-going future operation.[72] The unit experienced downtime during the summer of 2018, but that was related to damages caused by a severe storm. By the end of August 2018, the unit had captured 2,190,624 tonnes of CO_2 since commencing operation.[73]

Mike Monea, who lead the retrofit project, states that, "post-combustion capture has been demonstrated at commercial scale" and that "Boundary Dam pioneered the way for full-scale CCS around the world for coal and other industrial emission sources."[74]

The Cansolv process 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.[75] This process separates CO_2 from combustion exhaust gases using a liquid amine solvent.[76] Once absorbed by the solvent, heating removes the CO_2 as a high-stream.[77] For the Boundary Dam project, Cansolv offered process guarantees for steam consumption, CO_2 removed, electricity consumption and critical equipment, solvents and chemical consumption.[78]

In addition to SaskPower, Cansolv has successfully installed post-combustion technology on the Lanxess chrome chemical plant in Newcastle South Africa, capturing 170 Mtpa of CO_2.[79] The Lanxess plant captures CO_2 from the flue gas created by burning natural gas in conventional

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[71] *Id.*
[72] *Id.*
[73] Saskpower Blog, "BD3 Status Update: August 2018" https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-august-2018.
[74] Michael Monea, "An Update Report on the Integrated CCS Project at SaskPower's Boundary Dam Power Station," (Oct 22, 2018) presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018 (photos of slide on file with CATF).
[75] Cansolv Technologies Inc., Shell Global Solutions International BV, *Cansolv Technologies Inc. CO_2 Capture System* (2012), http://s02.static-shell.com/content/dam/shell-new/global/downloads/pdf/factsheet-cansolvco2.pdf.
[76] *Id.*
[77] *Id.*
[78] John Sarlis, Cansolv Technologies Inc., *Providing the Capture Process* (2013), https://www.yumpu.com/en/document/view/24417751/sk-ccs-symposeum-john-sarlis-cx-cansolv-revised.
[79] Cansolv Technologies Inc., Shell Global Solutions International BV, *Shell Cansolv CO2 Capture Underway in Unique Application* (2013), https://www.shell.com/business-customers/global-solutions/gas-processing-licensing/licensed-technologies/shell-cansolv-gas-absorption-solutions/cansolv-news-and-media-releases/shell-cansolv-co2-capture.html.

boilers.[80] Also, Cansolv Technologies in partnership with RWE power, piloted their process at the Aberthaw Power Station in South Wales.[81]

Bellingham NGCC, Bellingham, Massachusetts:

The Bellingham natural gas combined cycle (NGCC) plant in Massachusetts captured 330 tonnes of CO_2 per day from a 40 MW slip stream between 1991 and 2005. The CO_2 was sold to a beverage company. The plant closed in 2005 due to rising natural gas prices. The plant demonstrated Fluor's Economine FG process under plant conditions found in NGCC plants - 14% oxygen and 3% CO_2.[82] Fluor's capture process has been installed at 25 commercial projects over the past 20 years.[83]

b. Vendor offers demonstrate that carbon capture technology is available in the market for the power sector

There are three types of capture approaches applied to CO_2 in the power sector: post-combustion capture, pre-combustion capture, and oxy-fired approaches to fossil fuels that produce high-purity CO_2 without capture. The most common approach to coal and gas-fired power plant retrofits is post-combustion capture. This section describes the vendors and options available for the power sector using post-combustion capture. The technologies for all three approaches are described in Appendix B.

A large number of vendors offer carbon-capture systems for power plants. In addition to offering commercial capture systems for coal plants and a variety of boiler emissions, MHI states that its KM CDR Process® can be successfully applied to NGCC power plants.[84] MHI's solvent can withstand higher oxygen concentrations in NGCC applications.[85]

Fluor has said "[t]he Econamine FG+ technology is ready for full-scale deployment in: Gas- and Coal-fired Power plants,"[86] and commercial activity supports their assertion. While the project did not proceed, a January 2012 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,

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80 *Id.*

81 Shell, *New Life for Coal-Fired Power*, https://www.shell.com/business-customers/global-solutions/impact-magazine/new-life-for-coal-fired-power.html.

82 Dennis Van Puyvelde, Global CCS Institute, *Fluor's Econamine FG Plus* (2013), http://hub.globalccsinstitute.com/insights/fluors-econamine-fg-plus.

83 Fluor Corporation, *Refinery and Chemical Applications*, http://www.econamine.com/refinery_chemical_applications.

84 Mitsubishi Heavy Industries America, Inc., *MHI's Carbon Capture Technology* at 22 (2017), http://www.co2conference.net/wp-content/uploads/2017/12/4-MHI-Slides-on-the-PetroNova-Project.pdf.

85 *Id.*

86 Satish Reddy, Dennis Johnson & John Gilmartin, *Fluor's Econamine FG Plus[SM] Technology for CO2 Capture at Coal-fired Power Plants* (Aug. 2008), http://www.fluor.com/SiteCollectionDocuments/EFG_forCO2CaptureatCoal-FiredPowerPlants-PPAP_Aug2008.pdf.

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."[87]

Canslov offers its post-combustion capture system for a variety of industries, including coal-fired and NGCC plants.[88] Other vendors also have options to address carbon capture. These include Akers Solutions, Kerr-McGee/ABB, China's Thermal Power Research Group, and Norway's Aker and Alstom.

c. Geologic sequestration is available for all U.S. fossil fuel-fired plants.

Geologic sequestration of CO_2 is widely available to reduce carbon emissions from fossil fuel-fired power plants and other large point sources. Overwhelming evidence demonstrates that CO_2 can be injected and sequestered safely both in depleted oilfields and saline aquifers. First, nature's ability to contain fluids and gases in geologic formations is demonstrated by CO_2 and hydrocarbons that have been trapped for millions to hundreds of millions of years. Second, subsurface CO_2 management know-how is proven by five decades' worth of CO_2 injection and management experience in depleted oilfields.

Geologic carbon management and injection technology, used in both saline and EOR sequestration projects, is founded upon decades of experience transporting and injecting CO_2 in deep geologic reservoirs and supported by related forms of subsurface fluid management. Experimental CO_2 injections began over a half century ago in the West Texas Mead Strawn Oilfield in 1964, while commercial-scale CO_2 flooding began in 1972 at the SACROC field in Texas.[89] To date, more than 1 Gt of CO_2 has been injected in geologic formations throughout the world for the purposes of EOR. Large-volume geologic injections and disposal of wastewater are commonplace in the U.S.; including geologic wastewater injections, billions of tons of fluids are injected each year in the U.S.[90] Moreover, natural gas companies routinely use deep geologic storage for natural gas reserves, with nearly 3 Tcf stored presently.[91] There are over 400 sites in the U.S. alone where natural gas is injected and stored in saline aquifers, depleted natural gas reservoirs and salt deposits.[92]

There are several mechanisms by which CO_2 may be sequestered: CO_2 can be trapped physically by an impermeable barrier formation, dissolved in the saline formation water, or trapped in microscopic rock pores by capillary forces. In some geologic settings a portion of the CO_2 may be mineralized over long periods of time, thereby turning the CO_2 into rock itself. CO_2 can be

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87 Tenaska Trailblazer Partners, LLC, *Report to the Global CCS Institute: Final Front-End Engineering and Design Study Report*, at 15 (Jan. 2012), https://hub.globalccsinstitute.com/sites/default/files/publications/32321/traiblazer-front-end-engineering-and-design-study-report-final.pdf.

88 Shell Global Solutions International BV, *Industries that Cansolv Serves*, https://www.shell.com/business-customers/global-solutions/gas-processing-licensing/licensed-technologies/shell-cansolv-gas-absorption-solutions/industries-that-cansolv-serves.html#b1.

89 Bruce Hill *et al.*, *Geologic carbon storage through enhanced oil recovery*, 37 Energy Procedia 6808, 6811 (2013), https://www.sciencedirect.com/science/article/pii/S1876610213008576.

90 Wilson, E. *et al.*, *Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage*, 37 Environmental Sci. & Tech 3476 (2003), http://pubs.acs.org/doi/abs/10.1021/es021038%2B.

91 *See* EIA, *Natural Gas*, https://www.eia.gov/naturalgas/.

92 EIA, *The Basics of Underground Natural Gas Storage* (2015), https://www.eia.gov/naturalgas/storage/basics/.

sequestered in oil or gas fields in the process of producing hydrocarbons, or it may also be sequestered in associated saline reservoirs (in what is known as "stacked storage")[93] or in geologic (saline) formations bearing no hydrocarbons.

Numerous studies, as well as experience, have demonstrated that CO_2 injected for storage under a protective regulatory regime will be trapped and sequestered for millennia or more in rock with thousands of feet of vertical separation between the injected CO_2 and the surface. Subsurface CO_2 storage is secure if properly conducted. Building on a wealth of evidence and experience, a 2018 study, modeling leakage scenarios, demonstrates that CO_2 stored in well-regulated settings has a 98% probability that the CO_2 will be retained for over 10,000 years.[94] Furthermore, many recent studies have afforded the opportunity to better understand the fate of injected CO_2 at EOR sites. These studies have found no evidence of leakage.[95]

North America has widespread and abundant geologic storage options in deep porous saline brine-bearing formations and in depleted oil fields. The U.S. Geological Survey has mapped numerous deep, secure storage basins across the U.S., characterized by subsurface geologic formations with the capacity to sequester over 500 years of the U.S. total, current energy-related CO_2 emissions.[96] The DOE CarbonSAFE initiative has begun to identify promising regional storage "hub" basins with the geologic capacity to store gigatons of pipelined CO_2 both onshore in Midwest and southern U.S. basins and enormous offshore storage basins of the eastern and Gulf Coast U.S.[97]

d. All affected U.S. fossil fuel-fired plants are within a reasonable distance to transport CO_2 to sequestration injection sites via pipeline.

For facilities without geologic storage onsite, CO_2 pipelines provide the ability to transport CO_2 to suitable geologic storage sites. Transport of CO_2 by pipeline is also a proven commercial technology. Today, tens of millions of tons of CO_2 are transported by pipeline each year for injection into oil fields.[98] The DOE National Energy Technology Lab (NETL) demonstrated this in 2011, when it investigated the availability of geologic sequestration to 388 large coal plants. The report, "Coal-fired

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[93] Susan D. Hovorka & Scott W. Tinker. *EOR as sequestration: Geoscience perspective* (2010), https://repositories.lib.utexas.edu/handle/2152/67533.

[94] Juan Alcalde *et al.*, *Estimating geological CO_2 storage security to deliver on climate mitigation*, Nature Communications (June 12, 2018), https://www.nature.com/articles/s41467-018-04423-1.

[95] Katherine D. Romanak *et al.*, *Sensitivity of groundwater systems to CO2: Application of a site-specific analysis of carbonate monitoring parameters at the SACROC CO2-enhanced oil field,* 6 Int'l J. of Greenhouse Gas Control 142 (2012), http://www.sciencedirect.com/science/article/pii/S1750583611002039; Brian Hitchon, *Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the IEAGHG Weyburn-Midale CO_2 Storage Project* (2012); Susan D. Hovorka *et al., Monitoring a large-volume injection at Cranfield, Mississippi—Project design and recommendations*, 18 Int'l J. Greenhouse Gas Control 345 (2013), http://www.sciencedirect.com/science/article/pii/S1750583613001527.

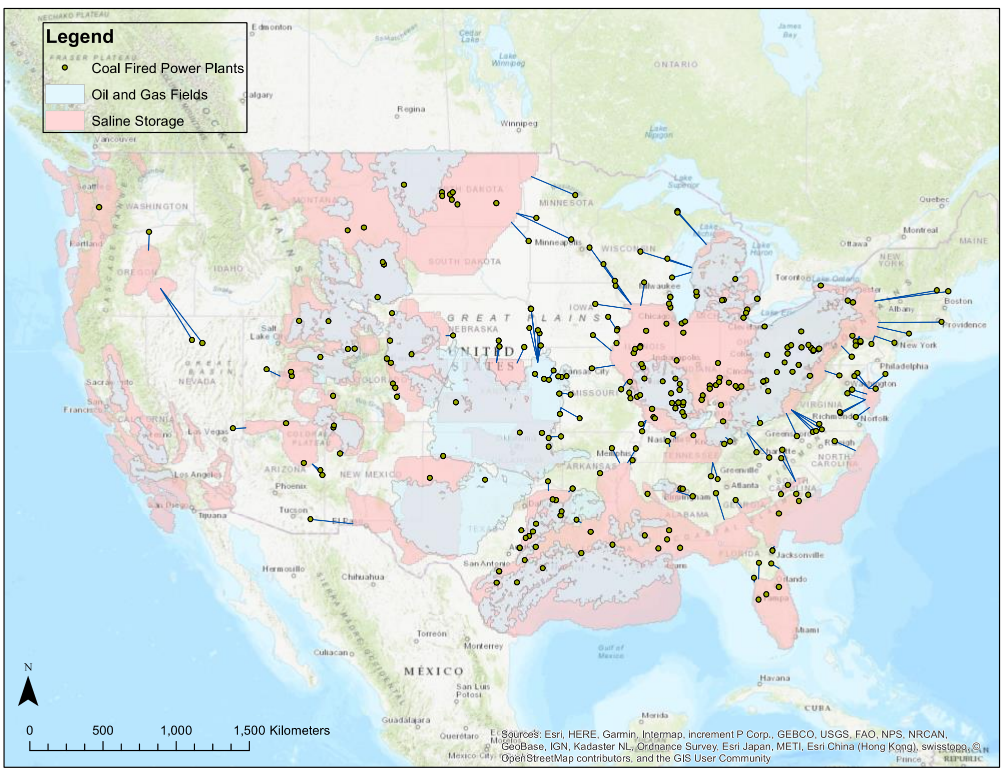
[96] U.S. Geological Survey, *National Assessment of Geologic Carbon Dioxide Storage Resources* (2013), https://pubs.er.usgs.gov/publication/fs20133020; U.S. Geological Survey, *USGS Releases National Assessment of Geologic Carbon Dioxide Storage Resources* (2013), https://energy.usgs.gov/GeneralInfo/EnergyNewsroomAll/TabId/770/ArtMID/3941/ArticleID/999/USGS-National-Assessment-CO2Storage.aspx. Additional capacity lies in the sedimentary basins not yet mapped by USGS.

[97] NETL, "CarbonSafe," https://www.netl.doe.gov/research/coal/carbon-storage-1/storage-infrastructure/carbonsafe.

[98] NETL, *A Review of the CO2 Pipeline Infrastructure in the U.S.* (2015), https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

Power Plants in the U.S.: Examinations of the Costs of Retrofitting with CO_2 Capture Technologies," found that 84 percent were within 25 miles of a sequestration site. As a follow-up in 2018, Clean Air Task Force commissioned a study by the University of Texas Gulf Coast Carbon Center to update the availability of geologic storage for the plants affected by the Proposal. The study, included in Appendix B, demonstrates each source can be matched to a reasonable storage site, further supporting inclusion of CCS in the BSER.

In order to illustrate source-sink analysis and to provide an estimate of the proximity to each source to geologic storage, CATF commissioned a screening study of the availability of geologic storage capacity for remaining plants subject to ACE by engaging Peter Tutton of the University of Texas Gulf Coast Carbon Center. The results of this GIS-based assessment demonstrate that ***all*** coal-fired power plants affected by the Proposal can be linked to a storage site. The investigation finds that half of the existing sources covered by this Proposal are within a mere 8 miles of a basin appropriate for the storage of CO_2 captured at those sources. In addition, 75% are within 31 miles and 95% are under within 125 miles from a basin that could store CO_2 and the volumes required. These distances are well within the range of today's pipelines, as highlighted in the NETL 2010 report. As a part of finalizing this rule, EPA must undertake a comprehensive, source-sink investigation to help determine the availability of storage for each individual U.S. coal plant as part of the BSER analysis.



Map showing applicable sources and proximity to a geologic storage site (P. Tutton for CATF 2018). Please refer to further discussion in Appendix B.

Additionally, a 2010 NETL report entitled: "A review of CO_2 pipeline infrastructure in the U.S." demonstrates the feasibility of CO_2 pipeline build-out. The report identified some 50 individual "safe, reliable" pipelines spanning over 4,500 miles, that represent "an essential building block for linking the capture of CO_2 from electric power plants…with its productive use in oilfields and safe storage in saline formations."[99] A 2011 DOE/NETL study examined transportation from plants to storage basins estimated transport costs to be $3.65 per tonne.[100]

Existing pipeline networks will provide the initial infrastructure framework for future pipeline network expansion that will be able to transport CO_2 captured from power plants and other sources to geological storage sites. An independent academic analysis commissioned by CATF demonstrates that all power plants affected under ACE have reasonable access to geologic sequestration capacity sufficient to sequester all of their CO_2 emissions.

As described in Appendix B, a regulatory construct exists to ensure storage integrity, and that CO_2 can be confidently permanently stored and accounted for. In addition, tax incentives adopted through enactment of the FUTURE Act in 2018 make geologic carbon storage more economic between now and 2030 than was assumed in the CPP analysis. Appendix B provides the results of the new analysis by the Texas Gulf Coast Carbon Center and a review of research published since the close of the previous public comment period on the Clean Power Plan.

It is important to note that, unlike the CPP, ACE would have states evaluate the BSER for plants on a case-by-case basis. Because CCS relies on technology applied to individual plants, EPA should consider CCS as part of the BSER, and undertake a source-sink evaluation of the availability of geologic storage for each plant.

V. <u>CCS costs are reasonable.</u>

EPA fails entirely to consider the costs of CCS in the Proposal. And as described above, the Agency mischaracterizes the Clean Power Plan record to dismiss CCS outright as "expensive." Regardless, "more expensive" than an alternative is not a legitimate basis for rejecting a meaningful measure that can significantly reduce emissions and that is not "exorbitantly" expensive. EPA's record in the Proposal on CCS costs is nonexistent, and therefore renders the rulemaking arbitrary, especially as critical learnings and cost reductions for CCS have occurred since the Clean Power Plan was finalized.[101] Additionally, the costs of CCS that EPA relies on in its IPM modeling for this rule are unreasonably high and do not take into account the most economic means of installing CCS or financial incentives available under current law. *See* Appendix A.

Therefore, we focus on primarily on two indicators of the cost-reasonableness of CCS here, which EPA must consider: 1) reductions for next plant retrofits based on the experience of Petra Nova and SaskPower; and 2) recent changes in federal law, which increased 45Q tax incentives for CCS and thereby significantly improved the economics of CCS on power plants.

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[99] *Id.* at 2.
[100] NETL, *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases*, 6 (Aug. 2012), https://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-DOE-341-082312.pdf.
[101] If the agency receives new and better data it must deal with it in a reasonable fashion and cannot blindly accept outdated or inaccurate information. *Dist. Hosp. Partners*, 786 F.3d at 57; *see also Flyers Rights Educ. Fund v. FAA*, 864 F.3d 738, 745 (D.C. Cir. 2017) ("Agency reasoning…must adapt as the critical facts change.").

Had EPA properly evaluated this information,[102] the Agency would have concluded that CCS is cost reasonable, certainly not exorbitantly costly, and an appropriate BSER for both coal and gas-fired power plants. Furthermore, EPA fails to adequately consider the technology-forcing impacts of rulemaking on innovation for CCS that could lead to much deeper CCS cost reductions over the next 15 years.

a. Costs of CCS

The ACE record fails to consider CCS cost reductions that the next CCS retrofits will gain as a result of constructing and operating the Petra Nova W.A. Parish Plant CCS retrofit and the SaskPower Boundary Dam Unit 3 retrofit.

Petra Nova Holding LLC recently submitted a report to DOE entitled, "W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project," as part of the grant requirements for the project. The report provides detailed process flow diagrams, heat and material balances, basic engineering and design data, and costs that were not part of the previous record.

Petra Nova's retrofit approach to the W.A. Parish plant differs from other projects because the steam and electricity used by the post-combustion capture unit comes not from the coal plant, but from a separate cogeneration plant that burns natural gas. This minimized integration into the existing coal plant and improved the project economics. As Petra Nova notes, the retrofit does not impact the Parish Plant's cost of electricity because the project included a cogeneration unit.[103] EPA failed to consider the benefits of separately supplying steam/electricity. In a low-gas price environment, this approach has important economic advantages. As a result, the CCS costs EPA uses in its IPM Modeling for ACE overstate the economic impacts of CCS.

Petra Nova believes that next CCS retrofit based on their approach will be at least 20% cheaper based on the experience of the W.A. Parish.[104] Approximately half of the savings come from eliminating "overkill" from the design that proved unnecessary based on the experience of W.A. Parish. The remaining savings come from learnings related to efficiencies that can reduce the amount of stainless steel and other bulk commodities used in the facilities.[105] Based on these cost reductions, Petra Nova estimates the cost of capture from the second project based on Parish Plant learnings to be about $2.5 per MCF or around $47/tonne.[106]

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[102] To comply with the APA the agency must examine the relevant data and show that they data is accurate and defensible. *See Dist. Hosp. Partners v. Burwell*, 786 F.3d 46, 57 (D.C. Cir. 2015). Courts require agencies to use "the best information available," *Catawba County v. EPA*, 571 F.3d 20, 45 (D.C. Cir. 2009).

[103] Petra Nova Parish Holdings LLC, "W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project," 10, https://www.osti.gov/scitech/biblio/1344080-parish-post-combustion-co2-capture-sequestration-project-final-public-design-report.

[104] David Greeson and Kenji Hagiwara, NRG, "Petra Nova Carbon Capture and Enhanced Oil Recovery Project," (Dec. 8, 2014), http://www.co2conference.net/wp-content/uploads/2015/01/5-Hagiwara-JX-Greeson-NRG-slides-11-9-14.pdf

[105] Personal Communication, David Greeson to CATF, (Dec. 13, 2017); *see also* Gardner *supra* note 112.

[106] David Greeson, "Petra Nova Capture Project" presented at International CCS Knowledge Centre Symposium on Carbon Capture, GHGT-14, October 21-25, 2018 (Attach. D).

EPA's record also does not contain any reference to reports prepared by International Knowledge Centre on CCS costs for a CCS retrofit of SaskPower's Shand plant. While SaskPower has not yet committed to undertake a second CCS project on their system, the most likely second project would be on the Shand Plant. The International CCS Knowledge Centre is an organization created by SaskPower to disseminate the company's insights and learnings gained from building the Boundary Dam 3 CCS retrofit. The Centre's most recent (attached) report shows projected cost reductions at Shand of 67% compared to the Boundary Dam 3 project.[107] The report notes, "factors such as scale, modularization, simplifications and other lessons learned as a result of building and operating the BD3 facility contributed directly to these reductions."[108] The report estimates that the projected cost of capture is $45/tonne (U.S. dollars).

The two approaches to capture retrofits represented by Petra Nova (which uses a separate gas-fired cogen plant to provide steam and electricity for the capture unit) and SaskPower (which provides steam and electricity for the capture unit directly from the coal plant) are complementary and expand the range of retrofit options available for the power sector. Appendix A compares the costs of these two approaches. In the appendix, CATF developed costs for a CCS retrofits that provide a separate boiler for supplying steam to the post-combustion power plant. This approach is similar to the cogeneration plant approach adopted by Petra Nova. The appendix compares these costs to the IPM costs for CCS that follow a SaskPower approach. The appendix concludes that a Petra Nova-like approach can be implemented in modules that improve the economics of smaller plants, while integrating the steam and electricity needs into the base plant (as SaskPower illustrates) can offer economies of scale that favor larger plants. Together, the two approaches offer capture options available to the wide range of plant sizes in the power sector.

The economics of CCS are project specific and determined on a case-by-case basis through detailed analysis. In general, the costs of CO_2 capture and transport must be lower than the revenue a CO_2 source receives from the sale of CO_2 for EOR and the value of 45Q tax credits. These costs and revenues and can be illustrated with some general, high-level numbers. The cost of transporting CO_2 is a relatively small cost. A DOE/NETL study examined transportation from plants to storage basins estimated transport costs to be $3.65 per tonne.[109] If capture costs are around $45/tonne, then project costs would be approximately $50 per tonne. To be economic in this illustration, revenue must exceed this $50 per tonne cost. The value of 45Q tax credits is $35 per tonne, leaving EOR revenue to pay for the remaining $15 per tonne cost. While EOR revenue varies based on oil price and operator, typical values for EOR revenue can range from $15 per tonne to $30 per tonne.[110]

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[107] Corwyn Bruce, *et al.*, *Post combustion CO2 capture retrofit of SaskPower's Shand Power Station: Capital and operating cost reduction of a 2nd generation capture facility*, presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018 (Attach C).
[108] *Id.* at 9.
[109] NETL, *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases*, 6 (Aug. 2012), https://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-DOE-341-082312.pdf.
[110] A common rule of thumb is that EOR revenue can be estimated at "2% of crude." The sales price for an MCF of CO_2 is 2% of the price of a barrel of oil. *See* Benjamin R. Cook, University of Wyoming, *Wyoming's Miscible CO2 Enhanced Oil Recovery Potential from Main Pay Zones: An Economic Scoping Study*, (Nov. 2012),

To assess CCS economics for the purpose of establishing policy, detailed models of the electric sector models are a valuable tool. These models provide a variety of outputs such as forecasts of capacity expansion, electricity dispatch and emissions outcomes under various scenarios.[111] Section VI of these comments presents the results of power sector modeling that considers both CCS policies and CCS economics based on the aggregation of detailed plant-by-plant cost estimates of capture, transport and transportation as well as revenue from EOR sales and incentives.

b. EPA failed to consider recent changes in federal law greatly expands tax credits for CCS

EPA neither mentions nor evaluates recent changes to federal law that make tax incentives available for CCS projects for industrial and power sectors. As a result, EPA overstates the economic impacts of CCS.

In February of this year, the Bipartisan Budget Act of 2018 became law. Among its many provisions, the law made changes to 45Q tax credits for CCS that were first adopted as part of the Recovery and Reinvestment Act of 2009.[112] The revisions authorized tax credits for each ton of CO_2 that is captured and stored 1) during the first twelve years after carbon capture commences and 2) at facilities that begin construction of such carbon capture equipment by December 31, 2023.[113] Although a project must begin construction by the close of 2023, the provision does not establish any deadline for completion of such construction.[114] The value of the credit depends on the year it is claimed. The credit grows over a 10-year period from an initial value to $35 per tonne for CO_2 stored through EOR. For saline storage, the credit value reaches $50 per tonne for CO_2 following a 10-year ramp. After 2026 the credit is adjusted to increase with inflation.

The changes represent a major departure from the existing 45Q. EOR was eligible for only $10 per tonne, not $35/tonne. Saline was only eligible for $20/tonne rather than the revised value of $50/tonne. Importantly, prior to enactment of the FUTURE Act, the credit was capped at 75

http://www.uwyo.edu/cee/_files/docs/2012_cook_wyomings_miscible_co2_eor_potential.pdf for an illustration of the range of EOR prices in Wyoming under various oil price scenarios.

111 For example, the IPM model used by EPA is described at https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm.

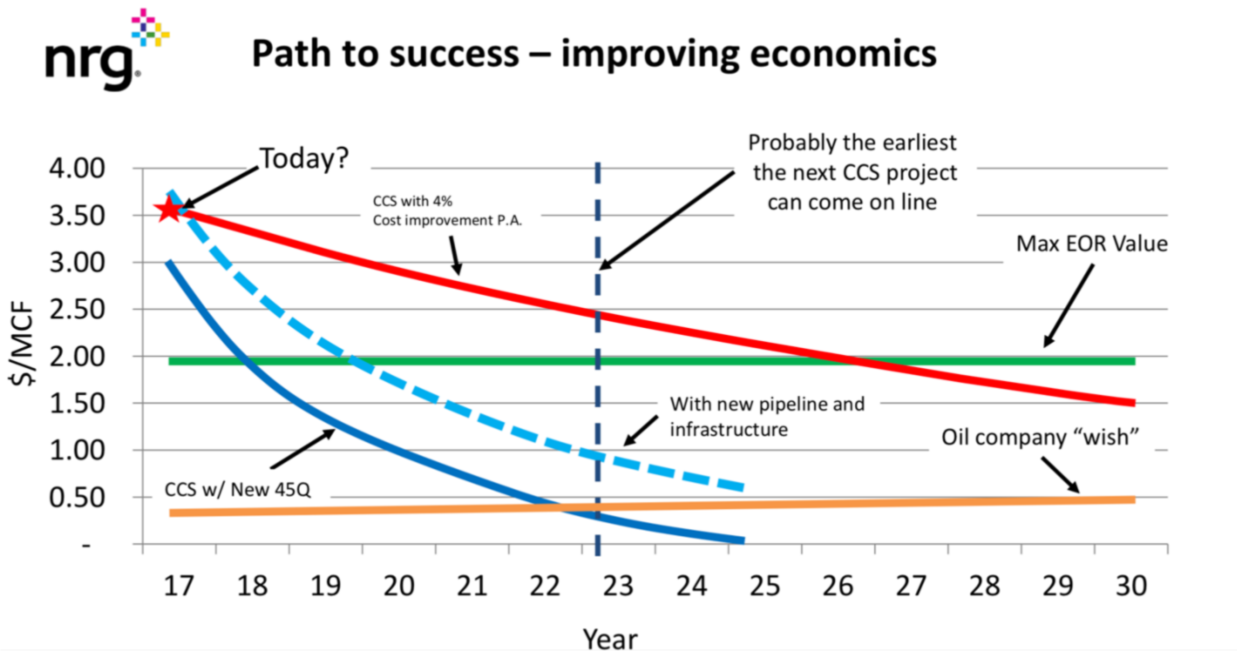
112 Bipartisan Budget Act of 2018 § 41119; *see also* Timothy Gardner, *Burying carbon emissions gets boost in U.S. budget deal*, REUTERS (Feb. 9, 2018), *available at*: https://www.reuters.com/article/us-usa-carbon-credit/burying-carbon-emissions-gets-boost-in-u-s-budget-deal-idUSKBN1FT2UT.

113 Only the storage provisions of the amended 45Q are described here. The Bipartisan Budget Act of 2018 also established credits for carbon utilization and other measures.

114 The IRS has not issued guidance indicating what activities meet the requirement that a facility begin construction by December 31, 2023. Tax credits for renewable projects, such as solar and wind, have a similar requirement that construction begin by a certain date and the IRS has issued guidance providing two tests, a physical work test and a 5% investment safe harbor provision. *See, e.g.,* IRS Notice 2016-31, 2016-23 IRB 1025, 05/05/2016. The IRS has also issued guidance on the requirement for continuous progress toward completion of construction, which provides, among other things, a list of "excusable disruptions" that excuse a delay in construction. *Id.* This list includes the delays in obtaining permits, financing delays and delays in construction of new transmission. *Id.*

million tonnes for the nation. Both the cap and the low value of the credit diminished the value of the original 45Q provisions

Accounting for 45Q significantly improves the economics of CCS for both for EOR and saline storage – as seen in the modeling results described below. David Greeson, the NRG Vice-President who oversaw the design, construction and operation of the Petra Nova project has stressed the importance of the revised 45Q incentives on future CCS projects. He notes that the earliest next CCS project could come on line by 2023. Such a project could be economic with 45Q credits and the previously discussed 20% reduction in Petra Nova costs as illustrated by the figure below:[115]



In the figure, the red curve shows the cost of capturing, transporting and storing CO_2 with EOR in $/MCF. The red line shows today's cost of $3.50/MCF (about $66 per tonne) falling over time. The green line shows the maximum price an EOR company might be willing to pay for CO_2. These lines cross in 2027, showing the earliest date at which CCS could be economic without incentives. The orange line represents what EOR would like to pay for CO_2 - a much lower price than the maximum price represented by the green line. The red and orange lines do not intersect in the time period shown on the graph. The effects of 45Q are illustrated by the blue curves. Subtracting the value of 45Q incentives from the red curve yields the new cost curve (solid blue curve) in the case where pipelines already exist. The blue curve meets the price EOR companies wish to pay for CO_2 in 2023. The dotted curve accounts for building a new pipeline on the costs of CCS-EOR. This line intersects the EOR company "wish" price in 2025. By the time the next plant comes on line, 45Q makes CCS-EOR economically attractive.

[115] David Greeson, "Petra Nova Capture Project" presented at International CCS Knowledge Centre Symposium on Carbon Capture, GHGT-14, October 21-25, 2018 (Attach. D).

Like those at Petra Nova, Mike Monea, who lead the SaskPower effort to retrofit CCS on Boundary Dam 3, states that with 45Q, "CCS would make sense" with a $45/tonne CO_2 capture cost that SaskPower determined could be achieved based on the learnings from Boundary Dam 3.[116]

i. EPA failed to model the impact of 45Q

The record developed by EPA to support the Proposal contains no modeling of 45Q.[117] This omission is significant given the importance of the credits to CCS deployment, as seen in modeling results reported below. What modeling EPA did in advance of the rule seems to contain an error in the calculation of variable operating and maintenance (VOM) costs.[118] While we understand that EPA has corrected this error since issuing the Proposal, the modeling in the Proposal record does not seem to reflect the correction.

c. Future costs of CCS will decline

Not only are the costs for CCS currently reasonable, as EPA explained in the Clean Power Plan record, it "expect[s] the costs of CCS to decline as implementation experience increases."[119] This is in line with "the history and the technological response to environmental regulations" that the Agency described as part of its determination that partial CCS was the BSER for new fossil fuel-fired power plants.[120] And EPA reaffirmed this perspective in 2017 when it explained "that carbon capture technology can be expected to continue to improve and become less expensive as it is deployed more."[121]

Costs of technology decline through several mechanisms. As more quantity of a technology is produced, costs can fall through "learning by doing." Costs can also fall through "incremental R&D." These efforts develop innovations that might otherwise have required extensive learning by doing. Finally, costs can fall through "transformational R&D." These efforts identify innovations that would not occur through either learning by doing or incremental R&D. Generally,

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116 Michael Monea, "An Update Report on the Integrated CCS Project at SaskPower's Boundary Dam Power Station," (Oct 22, 2018) presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018 (photos of slide on file with CATF).

117 EPA must at the very least include current laws in their modeling. "While the statute does not demand forecasting that is not meaningfully possible, an agency must fulfill its duties to the fullest extent possible." *Delaware Riverkeeper Network v. FERC*, 753 F.3d 1304, 1310 (D.C. Cir. 2014) (internal citations omitted).

118 Email from Serpil Kayin to John Thompson (Aug. 23, 2018) (Attach E).

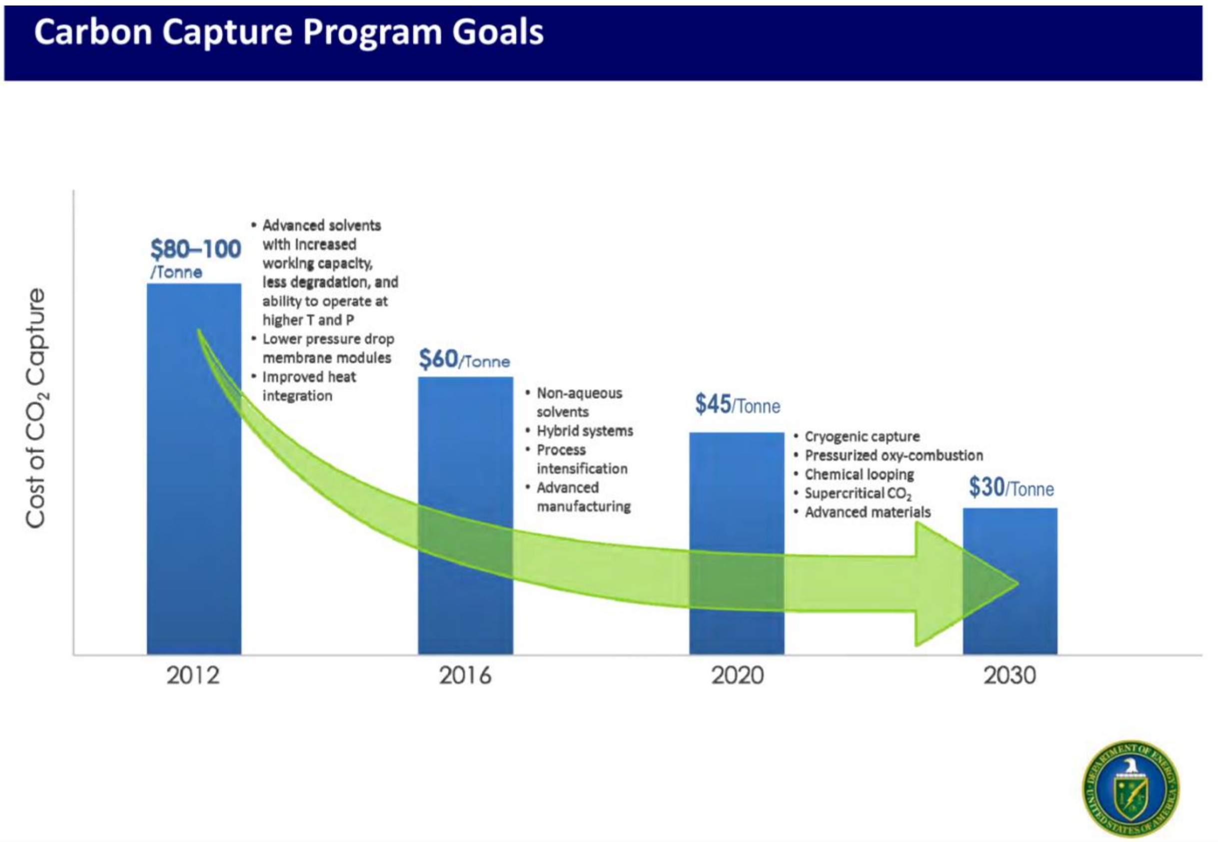
119 80 Fed. Reg. at 64,756 (citing Technical Support Document/Memorandum "History Of Flue Gas Desulfurization in the United States" (July 11, 2015) summarizing the doctoral dissertation of Margaret R. Taylor, "The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources," MA dissertation submitted to the Carnegie Institute of Technology, Carnegie Mellon University in partial fulfillment of the requirements for the degree of Doctor of Philosophy in Engineering and Public Policy, Pittsburgh, PA, January 2001).

120 80 Fed. Reg. at 64,756.

121 Reconsideration Denial, at App. 3, *Non-BSER CPP Flexibilities*, at 5 (Jan. 2017) (citing Br. for *Amicus Curiae* Carbon Capture and Storage Scientists, Doc No. 1652097, *North Dakota v. EPA*, No. 15-1381 (D.C. Cir. Dec. 21, 2016); and Br. for *Amicus Curiae* Technology Innovation Experts, Doc No. 1652263, *North Dakota v. EPA,* No. 15-1381 (D.C. Cir. Dec. 21, 2016)).

transformational R&D leads to deep cost reductions and higher performance relative to incremental R&D.[122]

The figure below depicts current DOE program goals for carbon capture innovation.[123]



The CO_2 capture cost of $45- $47 per tonne for next plants that Petra Nova and SaskPower project based upon their plants' experiences are consistent with DOE CCS program goals. DOE program goals seek a $45/tonne capture cost from CCS by 2020.

While DOE seeks to reach a capture cost of $30/tonne in 2030, it is possible that costs may fall even further. For example, a related technology under development by Net Power – which EPA points to in the Proposal – shows potential to both achieve an effective capture cost near zero and be ready sooner than 2030. The technology is directly applicable to new power plants, but the learnings will likely be transferrable to existing power plants. Net Power is testing a high pressure, oxygen-fired, natural-gas fired power plant in Texas. The operating conditions of the plant produce

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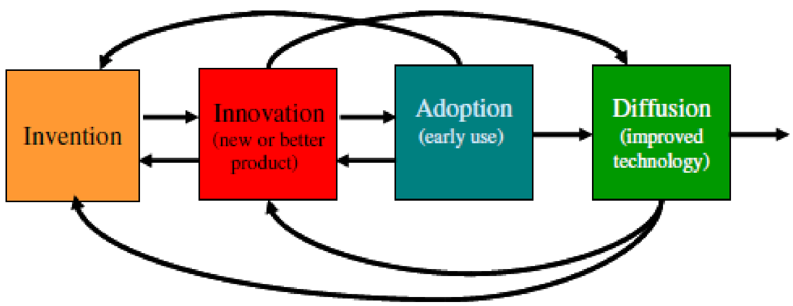
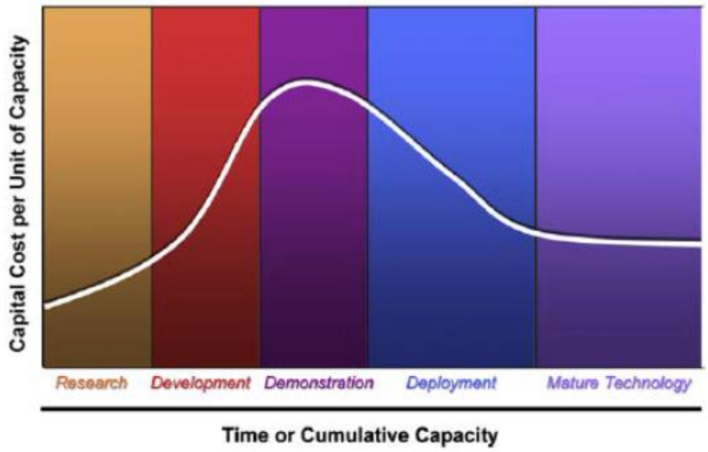
122 Shayegh *et al.*, *Evaluating relative benefits of different types of R & D for clean energy technologies*, 107 Energy Policy 532 (2017) (Attach. F).
123 Mark Ackiewicz, "Overview of the CCUS R&D Programs," (Aug 14, 2018) https://www.netl.doe.gov/File%20Library/Events/2018/mastering/tuesday/M-Ackiewicz-Keynote.pdf.

an inherently pure stream of CO_2 which is already at sufficient pressure for injection and storage. The 50MW plant expects to connect to the grid toward the end of 2018. Net Power estimates that their first commercial plants would produce electricity at around $19/MWh with 45Q incentives. That electricity price is about $30/MWh less than the cost of an uncontrolled NGCC plant. Without the 45Q incentives, the costs of electricity of their plant and an uncontrolled NGCC would be about the same.[124] EPA is following the development of Net Power.[125] The Agency, however, must do more than *follow* technology. EPA must propose technology-forcing rules, as the Clean Air Act requires, that support the development of advanced forms of CCS and energy systems like Net Power.

A central feature of technology-forcing regulations, like those required by section 111, is that they signal to the market that advanced CCS technologies or new technologies such as Net Power are needed, which in turn leads to a decline in capital and operation costs. The iterative process of continued learning-by-doing results in technological change, innovation, adoption and diffusion of improved technology and thereby lowers costs.[126]



[124] Bill Brown, "Demonstration and Commercialization of Net Power and Beyond" presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018 (photos of slide available on file with CATF).
[125] EPA explains that measures such as "the novel Allam Cycle —are, while seemingly promising, still in the early demonstration phase," 83 Fed. Reg. at 44,762 yet, as explained above, the Clean Air Act is technology-forcing and the best system of emission reduction is properly based upon literature review and operation of one plant in the U.S; "test programs;" 3) "pilot plant technology;" and 4) "testimony from experts and vendors." Net Power exceeds all of those criteria.
[126] Edward S. Rubin, *et al.*, *The outlook for improved carbon capture technology*, 38 ENERGY & COMBUSTION SCI. 1, 10 (Oct. 2012), https://pdfs.semanticscholar.org/2cc2/f32ba286b1fbb965e8562c4adeaa488a0069.pdf.



Source: Edward S. Rubin, *et al.*, *The outlook for improved carbon capture technology*, 38 ENERGY & COMBUSTION SCI. 1, 10 (Oct. 2012).

Experts "have observed that pollution regulation stimulates innovation and deployment of technology to meet that standard, which leads to design and operating improvements, which in turn reduces costs further."[127] For example, when EPA adopted the first SO_2 performance standards in 1971 there were only three units with scrubbers in operation and only one vendor. By the end of the decade there were sixteen vendors and scrubbers were the industry standard.[128] The vendors were able to cut the capital costs of scrubbers in half over twenty years.[129] Experts have shown that regulations consistently lead to spikes in patent filings related to the relevant pollution controls.[130]

History, as well as current learning, demonstrates that CCS costs will decline significantly in the short term and EPA must take this reality into account.

VI. Modeling Results

The modeling results described below confirm that CCS is adequately demonstrated, available and can effectively reduce carbon pollution at reasonable costs. To the extent that EPA does not adopt a system-based approach, EPA must include CCS in the BSER for affected sources.

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[127] Br. for *Amicus Curiae* Technology Innovation Experts, at 5, Doc No. 1652263, *North Dakota v. EPA,* No. 15-1381 (D.C. Cir. Dec. 21, 2016); *see also* Margaret Taylor, *et al.*, *Regulation as the Mother of Innovation: The Case of SO2 Control*, 27 L. & Policy 349, 357 (2005), http://content.ccrasa.com/library_1/30451%20-%20Regulation%20as%20the%20Mother%20of%20Innovation,%20The%20Case%20of%20SO2%20Control.pdf.

[128] *Id.* at 9-13, (citing Larry Parker & James E. McCarthy, Cong. Research Serv., Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources under the Clean Air Act, at 18 (May 14, 2009), https://fas.org/sgp/crs/misc/R40585.pdf; and Margaret Taylor, *et al.*, *Regulation as the Mother of Innovation: The Case of SO2 Control*)

[129] Margaret Taylor, *et al.*, *Regulation as the Mother of Innovation: The Case of SO2 Control.*

[130] Margaret Taylor, *et al.*, *Control of SO2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.*, 72 TECH. FORECASTING & SOCIAL CHANGE 697, 710 (2005), https://www.cmu.edu/epp/iecm/rubin/PDF%20files/2005/2005d%20Taylor%20et%20al,%20Tech%20Forecasting%20and%20Soc%20Chg%20(Jul).pdf.

First, the modeling shows that when the 45Q tax credit is included, CCS retrofits are built in the reference case, even absent a regulatory driver. Second, model runs that implement CCS as a source-specific BSER achieve significant emission reductions at costs that are reasonable and with benefits that far exceed those costs. These runs confirm that CCS is a far better source-specific BSER option than heat rate improvements. Finally, the system-based and source-specific approaches are contrasted through two model runs that deploy roughly similar targets, one of which uses an illustrative system-based policy (implements mass-based emissions targets) and one of which achieves a roughly similar target through source-based CCS limits.

This suite of modeling results confirms that 1) a system-based approach is preferable to a source-based approach; and 2) CCS must be included in the BSER if EPA limits itself to a "source specific" interpretation of the Clean Air Act. To do otherwise would be arbitrary, capricious and not in accordance with the Clean Air Act.

The sections below begin with the brief description of a run where NRDC and CATF replicated, as much as possible, the set of assumptions used by EPA and added the 45Q tax credits, which EPA did not model. The following discussion then explains the NRDC modeling results, which use some updated model inputs and other adjustments discussed in greater detail in the Joint Environmental Comments on RIA Issues at Part II and Appendix B of the NRDC modeling.

a. Using EPA's modeling assumptions and correctly reflecting the 45Q tax credit results in CCS builds even in the No Policy case.

When EPA modeled the No CPP, CPP and three policy scenarios for its Regulatory Impact Analysis accompanying the ACE Proposal, none of the runs resulted in CCS retrofits. This is due to EPA's failure to include the 45Q incentive, an "on-the-books" law, which provides CCS projects with a tax credit for sequestering carbon, as discussed above. CATF and NRDC undertook modeling in IPM to evaluate the impact of the tax credit on CCS builds, and, as discussed in detail below, found that inclusion of the tax credit did affect the modeled outcome.

In order to isolate the effect of EPA's failure to include 45Q, CATF and NRDC ran a reference (No Policy) case using the IPM model based on a set of assumptions as similar as those underpinning EPA's No CPP case as possible, but adding the 45Q tax credit. This alternate reference case otherwise relies on the same natural gas prices, renewable energy costs and oil price estimates used in EPA's own modeling. This reference case (assuming no carbon pollution limits) resulted in **6.5 gigawatts (GW)** of CCS retrofits on coal EGUs by 2030.[131] As described in section (b), CCS retrofits are also constructed in the updated reference case presented below.

EPA must account for 45Q in its analysis of the ACE rule. As the CATF and NRDC model run demonstrates, CCS retrofits are economic even in the absence of a regulatory driver. The fact that any CCS retrofits (much less 6.5 gigawatts) are deployed in a case that includes no carbon pollution limits demonstrates that CCS must be deployed as part of the BSER, especially in the context of EPA's "source-oriented" approach. In addition to the currently operating projects and evidence

[131] The full data for this EPA-like run is included in Appendix D of these Joint Comments.

showing that CCS is adequately demonstrated and available at reasonable costs, these results support including CCS in the best system of emission reduction.

b. NRDC's modeling demonstrates that the deployment of CCS results in large emissions reductions at reasonable costs and thus should be considered in the BSER

The NRDC modeling results show large emission reductions at reasonable costs through the deployment of CCS, demonstrating that CCS is a better emissions reduction option compared to heat rate improvements and that EPA must consider CCS as a source-specific emissions reductions measure in its construction of the BSER. The consistent CCS buildout across disparate modeling scenarios points to the robustness of this conclusion: cost-effective CCS retrofits on coal and gas EGUs are selected by the IPM model's cost-optimizing compliance feature in all runs. This includes both runs that were designed using CCS as part of the BSER to establish performance targets for coal and gas EGUs as well as scenarios developed based on gas co-firing on coal EGUs. It also includes scenarios that implemented a rate-based emissions targets structure and those that implemented a mass-based system-wide emissions cap. The sections below provide a detailed description and interpretation of the dynamics observed in the NRDC modeling.

i. Description of the NRDC CCS modeling and assumptions

a. Carbon capture, transportation and storage assumptions

Consistent with EPA's approach, the CO2 capture process both for new builds and plant retrofits is modeled assuming the use of an amine-based, post-combustion CO2 capture system.
NRDC relied on the same set of assumptions as EPA for the costs of carbon capture for coal EGUs. The assumptions are embedded in IPM version 6.[132] As for new NGCC plants with CCS and CCS retrofits on existing NGCC plants, NRDC relied on costs from the EIA's 2018 Annual Energy Outlook.[133] NRDC also relied on the EPA IPM version 6 carbon transportation costs.[134]
The primary distinction between NRDC's and EPA's approaches to representing CCS in IPM is the treatment of oil prices in the estimation of carbon storage costs. The storage cost curves embedded in IPM v6 include zero and negative cost steps representing storage available from EOR; oil producers and field operators either pay or offer free storage for carbon that is injected in oil wells to recover additional quantities of oil that would otherwise be difficult to extract. EPA relies on the Geosequestration Cost Analysis Tool (GeoCAT), a model that develops total storage potential at a series of costs (negative or positive). EPA aggregated these outputs into 19 steps reflecting a particular quantity and cost of storage ranging between -$27/ton and $54/ton (2016$); the value of the carbon for EOR was calculated using the average price of crude oil from the 2016 Annual

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[132] The following link includes the CO_2 capture costs for new units and retrofits, as well as the storage cost curves and transportation cost matrix https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_chapter_6_august_23_2018_updated_table_6-2_0.pdf.
[133] NGCC CCS costs are included in Appendix C.
[134] https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_chapter_6_august_23_2018_updated_table_6-2_0.pdf.

Energy Outlook Reference Case for the years 2025 to 2040, or $109/barrel (2016 dollars).[135] While NRDC followed the same approach, it aggregated the EOR storage potential based on the changing oil price between 2020 and 2050 projected in the 2018 Annual Energy Outlook Reference Case, instead of EPA's constant oil price figure. Therefore, the annual amount of storage available in each EOR cost step in NRDC's runs is slightly different compared to the EPA approach, as it varies based on the oil price for that year.

135 https://www.epa.gov/sites/production/files/2018-06/documents/epa_platform_v6_documentation_-_june_7_2018_-_chapter_6.pdf.

b. CO_2 capture rate

Similar to EPA, NRDC only offered the option of retrofitting CCS to existing coal-fired power plants and NGCC at a capture efficiency of 90 percent. Similarly, and also consistent with EPA's assumptions, NRDC's modeling assumes a CCS option with a CO_2 capture efficiency of 90 percent is available for new NGCC units.

c. The 45Q tax credits

As discussed in detail in Section V of these comments, EPA did not model the revised 45Q tax credits. NRDC modeled the tax subsidies as reflected in current law: units that undertake CCS retrofits receive a tax credit of $35/ton for carbon sold for EOR and $50/ton for carbon permanently sequestered, by 2026. As per current law, the tax credits are assumed to increase at the rate of inflation after 2026. Table 1 below summarizes the tax credits offered to units that install CCS. In addition, NRDC modeled the twofold sunset provisions, as laid out in current law: in order to qualify for the 45Q tax credits, units would need to begin construction by January 1, 2024. For those eligible units, the tax credits would phase out 12 years after the start of operation. As discussed in greater detail below, NRDC's modeling shows that properly accounting for the 45Q tax credit is an important driver of CCS buildout. EPA's failure to properly model the combination of revenues from the sale of carbon for EOR applications and 45Q subsidies means that it does not accurately reflect opportunities for cost-effective CCS buildout.

Table 1: 45Q Tax Credit (Nominal $/Metric Tonne through 2026, and then real 2026$ thereafter, per the legislation)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
EOR	32.5	35.0	35.6	36.3	37.0	37.6	38.3	39.0	39.8	40.5	41.2	42.0
Storage	47.0	50.0	50.9	51.9	52.8	53.8	54.8	55.8	56.8	57.9	58.9	60.0

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
EOR	42.8	**43.6**	44.4	45.2	46.0	46.9	47.7	48.6	49.5	50.4	51.3	52.3
Storage	61.1	**62.2**	63.4	64.5	65.7	66.9	68.2	69.4	70.7	72.0	73.3	74.7

	2049	2050
EOR	53.2	54.2
Storage	76.0	77.4

ii. <u>Description of the NRDC model runs</u>

The table below lists the set of runs that either assume CCS as part of BSER or where CCS features as a compliance option in both fossil fuel emissions rate or system-wide mass-based policies. The sections below discuss the results in detail.

Table 2: NRDC CCS Model Runs

Run	Source-specific vs. System-wide targets	Relationship between CCS and BSER	Description	Trading Level	2030 Carbon Emissions (million short tons)	% Reduction from 2005	CCS retrofits by 2030	Incremental Energy Efficiency Deployment (compared to No CPP)
No CPP	-	-	Baseline. No additional policies beyond those currently in place.	-	1,710	36%	8 GW coal retrofits	None
CCS-1	Source-specific	CCS is part of BSER	Rate targets enforced for existing coal EGUs (details in section iii below)	Facility-level averaging only	1,062	60%	33 GW coal retrofits	None
MASS-2	System-wide	Illustrative system-based BSER. CCS is one compliance option to meet the mass-target	Mass-based emissions limits achieving the same level of ambition as CCS-2; 100 lbs/MWh rate enforced on new NGCC units	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	1,031	61%	31 GW coal retrofits 15 GW new NGCC with CCS	None
CCS-2	Source-specific	CCS is part of BSER	Rate targets enforced for existing and new fossil fuel EGUs (details in section iii below)	Facility-level averaging only	838	69%	47 GW coal retrofits 89 GW NGCC retrofits	None
CPP-1	System-wide	CCS not part of BSER. It's a compliance option.	2015 CPP targets implemented on existing and new coal and gas EGUs	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	1,669	37%	10 GW coal retrofits	None

CPP-2	System-wide	CCS not part of BSER. It's a compliance option.	CPP with updated targets for 2018. Run implements a combined tonnage limit for existing and new sources. 100 lbs/MWh rate enforced on new NGCC units	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	1,090	59%	29 GW coal retrofits	None
COF-1	Source-specific	CCS not part of BSER. It's a compliance option.	Rate targets enforced for existing coal EGUs (details in section iv below)	Facility-level emissions averaging only	1,384	48%	25 GW coal retrofits	None

c. NRDC Modeling Results

As discussed above, EPA did not include the revenues from the 45Q tax credits in its modeling of ACE. In contrast, the NRDC modeling effort did include the 45Q credit. As discussed in greater detail in the Joint Environmental Comments on RIA Issues Part II and Appendix B of the NRDC comments, NRDC relied on the EIA's most current gas price projections and NREL's latest renewable energy cost projections.

The modeling result that most plainly demonstrates that CCS must be part of BSER is the NRDC reference case. Similar to the reference case discussed in section a) above that relies on EPA's own assumptions, the NRDC reference case results in significant levels of CCS without any emissions reduction requirement.

It is also important to emphasize that NRDC did not assume any decline in the carbon capture costs to reflect the learning-by-doing effect expected by industry.[136] Similarly, and as mentioned above, NRDC relied on the same carbon capture costs and applied the same capture process as EPA; the process assumes that units that retrofit with CCS incur a large heat rate and capacity penalty. In contrast, CATF has analyzed different retrofit techniques that lower capture costs and reflect the approach used at the Petra Nova CCS plant in Texas. These lower costs are a better estimate of current costs given that they are based on a successful and operational project.[137] This means that NRDC's modeling runs likely overstate carbon capture costs. The fact that the modeling shows consistent buildout of CCS across the runs despite the likely inflated capture costs further demonstrates the technology's cost-effectiveness.

i. Impact of the 45Q tax credits and EOR opportunities help make CCS cost-competitive among low-carbon generating resources

Table 3 below aggregates the 45Q tax credits and revenues from EOR sales received by units retrofitted with CCS. When added to the total carbon capture costs,[138] the 45Q tax credits and EOR payments put significant downward pressure on the industry's total CCS costs, reducing those costs by as much as 72 percent by 2030 (Table 4).[139]

Table 3: 45Q tax credit and EOR payments, listed as negative CCS costs ($ millions)[140]

	2020	2025	2030	2035
No CPP	0	-3,751	-3,784	-3,444
CCS-1	0	-10,930	-12,505	-10,958
MASS-2	0	-11,315	-12,883	-11,583

136 The projected decrease in capture costs is discussed in greater detail in Section V and Appendix A.
137 The CATF capture costs are discussed in depth in Appendix A.
138 Carbon capture costs include the levelized capital costs of retrofitting with CCS, as well as fuel costs, fixed O&M and variable O&M costs of retrofitted EGUs.
139 CCS costs include capture costs listed above, as well as carbon transportation costs.
140 The 45Q tax subsidies phase out by model year 2040 reflecting the credits phaseout 12 years after units commence operation.

CCS-2	0	-17,866	-23,959	-19,553
CPP-1	0	-4,540	-5,506	-5,003
CPP-2	0	-10,774	-11,504	-10,336
CPP-2LO	0	-7,797	-8,131	-7,026
COF-1	0	-8,539	-10,769	-9,617

Table 4: Percent reduction in total carbon capture and transportation costs owing to 45Q tax credit and EOR payments

	2020	2025	2030	2035
No CPP		-72%	-72%	-66%
CCS-1		-53%	-56%	-49%
MASS-2		-56%	-47%	-43%
CCS-2		-32%	-29%	-24%
CPP-1		-72%	-84%	-77%
CPP-2		-57%	-61%	-55%
CPP-2LO		-54%	-56%	-49%
COF-1		-60%	-60%	-54%

Table 5 below summarizes the total CCS costs as a percentage of total system costs: in all cases except CCS-2 (which is included primarily to illustrate the cost difference between source-based and system-based approaches), CCS costs account for a small share of the total system costs – up to 9 percent in 2030- owing to the impacts of 45Q and EOR payments. This cost dynamic explains the modest to large CCS buildout occurring in all of the NRDC runs and highlights the economic potential for CCS that EPA did not explore.

Table 5: Total CCS costs[141] as a percentage of total system costs

	2020	2025	2030	2035
No CPP		1%	1%	1%
CCS-1		7%	6%	7%
MASS-2		6%	9%	9%
CCS-2		23%	31%	32%
CPP-1		1%	1%	1%
CPP-2		6%	5%	5%
CPP-2LO		5%	4%	4%
COF-1		4%	5%	5%

[141] Total CCS costs include the following elements: capital costs of the CCS retrofit; VOM, FOM and fuel costs for the retrofitted plant; carbon transportation and storage costs; and 45Q payments.

To examine the sensitivity of the CCS outcomes to a change in oil prices with a policy driver in place, NRDC included CPP-2LO, assuming low oil price projections from the 2018 Annual Energy Outlook High Oil and Gas Resource and Technology side case.[142] In this side case, the average oil price between 2025 and 2040 is 16 percent lower compared to the AEO 2018 Reference Case. Low oil prices measurably lower potential EOR revenues, and thereby reduce the cost-effectiveness of CCS projects for plant operators, absent additional incentives to install CCS. However, while EOR revenues are more than halved in CPP-2LO by 2030 compared to CPP-2, CCS retrofits on coal EGUs only drop by 5 GW, or 17 percent (Table 6). Approximately $6 billion in 45Q tax credits in 2030 enhances the cost-effectiveness of CCS projects, despite the decrease in EOR revenues. In fact, 45Q tax credits and EOR payments still lower the CO_2 capture costs and transportation by more than 55 percent by 2030 (Table 6). The CPP2-LO outcome taken together with the cost-effective CCS additions across the other scenarios,[143] confirms the availability of CCS supported in large part by the availability of the 45Q tax credits. **As discussed in Section V, it is critical for EPA to model the degree to which 45Q tax credits will lower costs for initial projects and, as additional projects are constructed, bring down the costs of future CCS deployment. CCS builds across these various sensitivities further establish that it is an adequately demonstrated system, which must be part of the BSER for existing power plants under a "source-oriented" rule.**

Table 6: Comparisons between CPP-2 and CPP-2LO

	2030 Storage Cost ($ Millions)	2030 45Q tax credits ($ Millions)	2030 Percent reduction in total carbon capture and transportation costs	2030 CCS Retrofits (GW)
CPP-2	-4,518	-6,986	-61%	29
CPP-2LO	-2,171	-5,960	-56%	24

The following sections discuss in greater detail the individual run results and their significance.

ii. The CCS buildout in the NRDC No CPP case demonstrates its economic potential

The NRDC No CPP case, which assumes no carbon pollution limit, shows 8.2 GW of CCS retrofits on coal EGUs by 2025. All of the retrofitted capacity is located in four states- Texas, New Mexico, Montana and Louisiana (Table 7). As shown in Section IV and Appendix B, and in congruence with the storage cost curves embedded in IPM v6, these states have large EOR potential and house, or are in proximity to, existing CO2 pipeline infrastructure. Thus, a share of coal EGUs in these states retrofits with CCS by 2025 to take advantage of both the 45Q credits and EOR sales, absent any emission standard. In fact, the 45Q tax credits and EOR payments lower the carbon capture and transportation costs by more than 70 percent in 2030 for the plants that retrofit (Table 8): as a result, the total CCS costs account for only 1 percent of total system costs in 2030 (Table 8). By not modeling 45Q, EPA overlooked this potential and with it an important source-specific option for

[142] The low oil prices are based on AEO 2018's High oil and gas resource and technology side case oil prices, https://www.eia.gov/outlooks/aeo/tables_side.php.
[143] The CCS buildout results across the NRDC runs are discussed in the following sections.

BSER. As described in the Joint Environmental Comments on BSER Issues, EPA cannot rule out a BSER on the grounds that it is not universally or widely available.

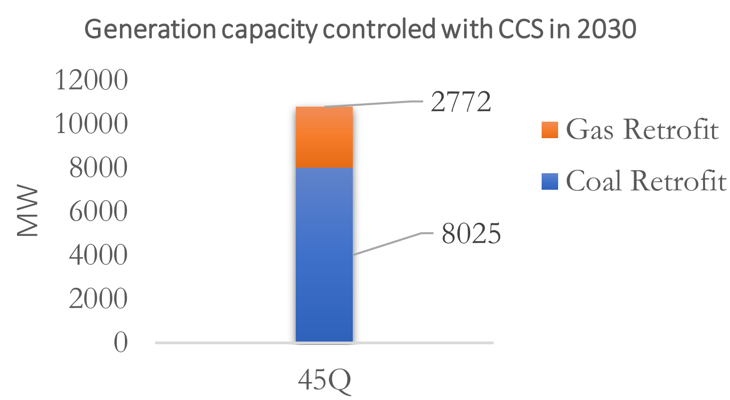
Table 7: CCS retrofits on coal EGUs in the NRDC No CPP run (GW)

	2020	2025	2030	2035
Louisiana	0	0.5	0.5	0.5
Montana	0	1.1	1.1	1.1
New Mexico	0	1.2	1.2	1.2
Texas	0	5.3	5.3	5.3

Table 8: CCS-related costs in the NRDC No CPP run ($ millions)

	2020	2025	2030	2035
% Reduction in total carbon capture and transportation costs[144]	-	-72%	-72%	-66%
Total CCS costs as % of total system costs	-	1%	1%	1%

Finally, these results are also consistent with findings from other modeling efforts. In particular, CATF retained Charles River Associates in June 2018 to determine the impacts of the 45Q credit on CCS builds in the power sector between 2018 and 2030.[145] The results showed CCS deployed on 8 GW of coal-fired generation at plants accounting for 10.8 GW of capacity, and 2.77 GW of gas-fired generation at plants accounting for 9.6 GW of capacity.[146] The coal plant retrofits capture 46 million short tons of CO_2 and NGCC retrofits capture 8.27 million short tons of CO_2, annually by 2030.[147]



[144] Carbon capture costs include the levelized costs of capital of CCS retrofits, variable and fixed O&M costs and fuel costs.
[145] CATF, "Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector," (July 2018), http://catf.us/resources/other/CATF_45Q_Analysis.pdf.
[146] *Id.*
[147] *Id.*

CCS retrofit projects resulting from 45Q tax credits are located close to EOR storage supply in California and the East & Central Texas and Permian basins. The following table shows the breakdown of carbon-controlled generating capacity by geography.

	Coal Retrofits (MW)	Gas Retrofits (MW)
Arkansas	173	
California		2,276
Kansas	1,399	1.2
Texas	3,687	332
Oklahoma	1,962	165
Missouri	804	
Total	8,025	2,733

Additionally, the Midwest Power Sector Collaborative recently commissioned a decarbonization study for the Midwest region, which shows large levels of CCS deployment in a reference case scenario: the study projects between 8 and 14 GW of CCS retrofits on coal EGUs by the mid-2020s.[148]

iii. Including CCS in the BSER would result in significant emissions reductions at reasonable costs.

In light of the evidence supporting including CCS in the BSER, bolstered by NRDC's No CPP case results showing significant potential for CCS, along with the geographic availability of carbon storage and pipeline infrastructure (Section IV and Appendix B), NRDC designed a set of runs that consider CCS as a component of a source-specific BSER. NRDC computed and enforced emission rates on existing and/or new fossil EGUs based on a certain level of CCS deployment.

NRDC ran a range of cases from options that include limited trading and enforce a high rate of carbon capture on both existing and new coal and gas plants to runs that allow greater compliance flexibility or limit the carbon capture standard to existing coal EGUs. Importantly, the benefits of all of the runs that NRDC performed, even those that achieve the greatest level of emission reductions, have benefits that exceed the costs by a factor of two to one, at a minimum.[149] Thus, all of the runs

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[148] Midcontinent Power Sector Collaborative & Great Plains Institute, A Road Map to Decarbonization in the Midcontinent, (July 2018), http://roadmap.betterenergy.org/wp-content/uploads/2018/08/GPI_Roadmap_NRDCb.pdf.

[149] The climate and health co-benefits are computed using the 2030 global social cost of carbon and monetized benefits of reducing harmful pollutants like NO_x and SO_2 that EPA used in the 2015 CPP. The 2030 global social cost of carbon is listed in Table 4-2 in the 2015 CPP RIA; https://archive.epa.gov/epa/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf .

As we discuss elsewhere, EPA has unlawfully proposed an approach to estimating benefits that arbitrarily understates the benefits of reducing CO_2 and associated pollutants from the power sector. Moreover, under the Clean Air Act, demonstrate the potential for CCS to be considered as a source-specific system of emission reduction for existing power plants.

Tables 9 and 10 below summarize the run specifications and highlight some of the main results.

EPA's duty is to set standards reflecting the best system of emission reduction and EPA may not reject highly cost-effective approaches based on a claim that the benefits are less than EPA's projected costs, using EPA's unfounded assumptions about benefits.

Table 9: Modeled emissions standards for fossil fuel EGUs

Run	BSER specifications	Level of CCS deployment assumed in the BSER	Emissions standards	Trading Level	Incremental Energy Efficiency Deployment (compared to No CPP)
CCS-1	Source-specific	Existing coal EGUs: 55% carbon capture (90% capture at nearly 60% of units; trading between units at a coal plant) No standard on existing or new NGCC plants	Coal: 1,578 lbs/MWh in 2025; 1,058 lbs/MWh in 2030; and 892 lbs/MWh in 2035 No standard on existing or new NGCC units	Facility-level emissions averaging only	None
MASS-2	System-wide	Mass limits on existing coal and gas EGUs equivalent to CCS-2; System-wide compliance is allowed. 100 lbs/MWh rate on new NGCC plants still applied	Existing-only mass targets: 2025: 1,197,793,439 tons 2030: 824,770,481 tons 2035: 706,615,289 tons Rate on new NGCC plants: 100 lbs/MWh	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	None
CCS-2	Source-specific	Existing coal EGUs: 55% carbon capture (90% capture at nearly 60% of units; trading between units at a coal plant) Existing NGCC plants: 55% carbon capture (90% capture at nearly 60% of units; trading between units at a gas plant) New NGCC plants: 90% carbon capture on all new plants	Coal: 1,578 lbs/MWh in 2025; 1,058 lbs/MWh in 2030; and 892 lbs/MWh in 2035 Existing NGCC: 603 lbs/MWh in 2025; 404 lbs/MWh in 2030; and 341 lbs/MWh in 2035 New NGCC: 100 lbs/MWh starting in 2025, maintained thereafter	Facility-level emissions averaging only	None

Table 10: Emissions, costs and CCS buildout for CCS BSER model runs and comparable system-based model run

Run	2030 Carbon Emissions (million short tons)	% Reduction from 2005	Reduction in NOx and SO2 Emissions compared to No CPP, in 2030	2030 Total System Compliance Costs (2016$ billion)	Climate and Health Benefits (2016$ billion)	Benefits/Costs Multiplier	CCS retrofits by 2030	2030 Carbon Price (2012 $/ton)
No CPP	1,710	36%	-	-	-	-	8.2 GW coal retrofits	-
CCS-1	1062	60%	39% reduction in NOx; 59% reduction in SO2	$16.7 billion	$61 - $111 billion	3.7 – 6.6	33 GW coal retrofits	-
MASS-2	1031	61%	38% reduction in NOx; 52% reduction in SO2	$16.7 billion	$59 - $107 billion	3.5 – 6.4	31 GW coal retrofits 15 GW new NGCC + CCS No NGCC CCS retrofits	$28/ton for existing fossil EGUs
CCS-2	838	69%	10% reduction in NOx; 43% reduction in SO2	$40.8 billion	$64 - $111 billion	2 – 2.7	47 GW coal retrofits 89 GW NGCC retrofits	-

There are many ways in which a standard that reflects the potential for carbon capture and sequestration might be designed. CCS is generally most cost-effective per ton of carbon pollution captured when a high percentage capture rate is achieved. For this reason, it is likely more cost effective to adopt an emission trading system that allows a portion of covered plants to install CCS with a high capture rate and allows other plants to comply through emission rate averaging rather than setting a standard based on a lower rate of capture that is required at each covered source. Emissions averaging is appropriate when the chosen system of emission reduction reflects the technology forcing nature of the Clean Air Act and represents maximum feasible control of pollutants,[150] and the pollutant is one global effect as opposed one with local or hazardous environmental or public health impacts. A BSER for CO_2 based on CCS would fulfill these statutory requirements. Additionally, the availability of emissions averaging must be incorporated into the stringency of standard.[151]

The initial case that NRDC modeled to illustrate how a CCS BSER standard could operate is CCS-1, which allows only intra-plant emission rate averaging in order to track the approach used in the ACE proposal.

It is important to recognize that an approach with a national trading system could help avoid the need to install CCS at plants where it is comparatively more expensive to do so. Such an approach is not inconsistent with EPA's narrow approach to BSER. EPA argues that the CPP approach is impermissible because the BSER is limited to reductions based on certain physical changes at power plants. As explained elsewhere, this interpretation is neither reasonable nor legally compelled. It also does not prohibit trading emission credits between coal-fired power plants.[152] Under such an approach, all covered stationary sources are given an emission rate limit but if one covered source over-complies, that source is allowed to average emission rates (on a generation-weighted basis) with other plants that are not in compliance. Under this approach, plants that can comply at lower cost can do so and sell credits to those that face higher costs, lowering the total system compliance costs. EPA has a long history of allowing this kind of emission trading.[153] Such compliance flexibility is fully consistent with the source-specific approach that EPA is proposing because the emission reductions considered are based on the restrictive approach to BSER that EPA has advanced, namely physical changes made at a covered source. Importantly, as mentioned above, any flexible measures permitted for compliance purposes must also be reflected in the BSER and its stringency.[154] As EPA considers how a CCS standard might be designed, it must evaluate methods to trade between covered sources even if it finalizes the highly restrictive BSER that it has proposed.

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150 1975 Implementing Regulations, 40 Fed. Reg. at 53,342; *see also id.* at 53,344 (stating that "section 111(d) requires maximum feasible control of welfare-related pollutants in the absence of" a reasoned basis for a less stringent approach, and that "EPA will promulgate plans requiring maximum feasible control if States fail to submit satisfactory plans for welfare-related pollutants").

151 *See* Comments of Clean Air Task Force, *et al.* on ACE Proposal, at Section VIII (Oct. 31, 2018).

152 EPA's restrictive and unlawful interpretation of BSER as being limited to source-specific measures is discussed in greater detail in the Joint Environmental Comments on BSER Issues

153 *See, e.g.*, 60 Fed. Reg., at 65,387 (Dec. 19, 1995) (municipal waste combustor guideline, which permitted averaging and emission credit trading); 70 Fed. Reg. 28,606, 28,617 (May 18, 2005) (Clean Air Mercury Rule); *see also Small Refiner Lead Phase-Down Task Force v. EPA,* 705 F.2d 506, 536 (D.C. Cir. 1983).

154 80 Fed. Reg. at 64,786, n. 623. ("The EPA has frequently required that sources meet a more stringent nominal limit when they are allowed compliance flexibility, particularly, the opportunity to trade.").

While NRDC did not model an emissions target based directly on a low level of CCS deployment, such a target could be designed, especially if compliance via emission rate averaging were permitted in EPA's rule.

1) CCS-1 achieves large emissions reductions, benefits far exceeding costs, and demonstrates that states have a large potential to tap into carbon storage opportunities

The CCS-1 run imposes emissions rate targets on coal-fired power plants based on the deployment of 55 percent carbon capture at each coal plant and assumes emissions rate averaging only between the units in each coal plant. The 55 percent carbon capture is based on the assumption that nearly 60 percent of the units at each coal-fired power plant retrofits with a 90 percent carbon capture system (Table 9). CCS-1 also assumes no incremental energy efficiency above the No CPP case. CCS-1 results in large carbon emissions reductions in 2030 – 60 percent compared to 2005 – at the reasonable, and plainly not-exorbitant, compliance costs of $16 billion by 2030 (Table 10).

As discussed in section c.i above, the 45Q subsidies and EOR payments significantly lower CCS costs. Even with 33 GW of coal EGUs retrofit with CCS by 2030, CCS costs only make up 6 percent of total system costs (Table 11). The compliance costs of $16 billion are far less than the benefits estimated to range between $61 to $111 billion (Table 10 above). **In fact, climate and health co-benefits exceed the costs by nearly 4 to 7 times. This confirms that EPA must evaluate a range of CCS deployment levels in the BSER. EPA should also model varying sensitivities on energy efficiency to provide an adequate evaluation of the system's compliance costs.**

Table 11: Total CCS costs[155] as a percentage of total system costs

	2020	2025	2030	2035
No CPP		1%	1%	1%
CCS-1		7%	6%	7%
MASS-2		6%	9%	9%
CCS-2		23%	31%	32%

The wide geographic distribution of CCS deployment in CCS-1 confirms that CCS is broadly available at reasonable cost. More than 30 states retrofit a share of their coal-fired power plants with CCS by 2030 to comply with the emissions standard, taking advantage of EOR opportunities at modest CO_2 transportation costs. Table 12 below summarizes the total 45Q subsidies, as well as the CO_2 storage and transportation costs. These results highlight a twofold conclusion: 45Q tax credits and revenues from EOR sales largely offset CO_2 transportation costs; and CO_2 transportation costs are modest, despite the large deployment of CCS.[156] These findings confirm the non-localized availability of EOR opportunities, as well as the potential for EGUs to take advantage of a wide network of existing CO_2 pipelines at modest cost to tap into the EOR potential.[157]

[155] Total CCS costs include the following elements: capital costs of the CCS retrofit; VOM, FOM and fuel costs for the retrofitted plant; carbon transportation and storage costs; and 45Q payments.
[156] 33 GW of coal retrofits by 2030.
[157] Existing CO_2 pipeline infrastructure is discussed in greater detail in Section IV and Appendix B.

Table 12: Post-capture costs and 45Q subsidies ($ millions)

	2020	2025	2030	2035
45Q subsidies	$0	-$7,933	-$9,097	-$7,189
Storage costs	$0	-$2,997	-$3,408	-$3,770
Transportation costs	$0	$2,691	$3,034	$3,114
Total	**$0**	**-$8,238**	**-$9,471**	**-$7,845**

These results confirm that EPA should have considered CCS in the BSER: EGUs have large opportunities to sell captured carbon for EOR applications by taking advantage of existing pipeline infrastructure at modest costs. **EPA should evaluate various levels of CCS deployment and, as noted above, model the impacts of a national, category-specific trading scheme that enables those EGUs that cannot cost-effectively retrofit with CCS to comply with emissions standards at reasonable costs.**

2) **Compliance flexibility can significantly reduce compliance costs**

As noted elsewhere in our comments, the constrained interpretation of BSER that EPA seeks to apply when setting standards also applies when considering the compliance options available. This means that if EPA determines that only options that involve physical changes to each power plant are considered when setting emissions targets, then compliance measures may also only include the same range of options. Specifically, if emissions rate averaging or other system-based flexibilities are not included when setting the BSER, they cannot be available for compliance.

In order to illustrate the difference between source-specific and system-based approaches, NRDC modeled a run reflecting a system-wide approach and roughly comparable source-based approach. MASS-2 implements a mass-based emissions cap on existing coal and gas units that achieves the same level of emissions reductions as CCS-2, which reflects a source-specific, rate-based approach (Table 9).

CCS-2 assumes that nearly 60 percent of units at a coal plant and 60 percent of units at a gas plant retrofit with a 90 percent carbon capture system. To track the ACE proposal's restrictive compliance structure, trading was limited to facility-level emissions averaging. Both CCS-2 and MASS-2 assume a 100 lbs./MWh target on new NGCC plants (Table 9).

MASS-2 takes a system-wide approach by setting an emissions cap on existing coal and gas units and requiring that each power plant obtain an emission allowance for each ton of pollution emitted. In the MASS-2 run, CCS deployment could be part of the BSER, along with other system-wide emissions reduction measures, like increased deployment of clean energy and utilization of lower-emitting resources. MASS-2 allows national trading of emission allowances among existing coal and gas units (Table 9). **This pair of runs shows that a system-wide approach can deliver emission reductions at far lower costs than an equivalent source-specific emissions rate approach.**

MASS-2 results in large emissions reductions - 61 percent reduction compared to 2005 - at the compliance costs of $16 billion by 2030 (Table 10). Climate and health benefits exceed the costs by up to 6 times by 2030. Significant levels of CCS are deployed in this run, confirming that CCS is an important compliance option capable of driving large emissions reductions at reasonable costs (Table 10).

The comparable source-based run (CCS-2) also achieves significant emission reductions but does so at costs significantly greater than its system-based counterpart. Although CCS-2 and MASS-2 were designed to achieve the same level of emission reductions, CCS-2 results in 8 percent more emissions reductions compared to 2005 levels, by 2030 (69 percent compared to 61 percent). This is because the source-specific emission rates lead to additional reductions in the utilization of covered sources. But more importantly, the system-based approach (MASS-2) achieves emissions reductions at much lower costs - 70 percent lower by 2030 - than the source-specific emissions rate approach (CCS-2).[158] The large cost differential illustrates that a system-based approach allowing trading flexibility can achieve large emissions reductions at significantly lower costs. Although NRDC did not have time to perform a pair of runs which would achieve identical emission outcomes, it is apparent from this 70 percent cost reduction that a system-based approach would still be far less expensive even if the emissions outcomes had been were identical.

The comparative results between CCS-2 and MASS-2 reflect the increased compliance flexibility inherent in a mass-based approach compared to a rate-based approach. Generally, the implementation of a mass-based target on existing coal and gas EGUs enables the power sector to respond in the most efficient manner possible, which includes the addition of non-emitting generation, use of energy efficiency as well as greater use of lower-emitting natural gas plants.

In conclusion, to the extent that EPA limits itself to a source-specific BSER, the Agency should consider various levels of CCS deployment and select one that results in the "maximum feasible control of pollutants" that can be achieved without imposing exorbitant costs. In addition, MASS-2 demonstrates that a system-wide approach can achieve reductions at lower costs and is therefore preferable.

3) Cost-effective CCS retrofits are deployed even when the BSER excludes CCS

In addition to the runs discussed above, NRDC modeled a set of runs that do not consider the deployment of CCS in the BSER. CCS was allowed as a compliance option along with other source-specific compliance strategies. One run – COF-1- reflects a BSER derived based on the implementation of gas co-firing on coal EGUs; as shown in Table 13 below, the emission-rate targets implemented on coal EGUs is lower compared to the targets that based on deployment of CCS (CCS-1, CCS-2). The remaining two runs- CPP-1 and CPP-2 - reflect a system-wide BSER that exclude CCS deployment and allow system-wide compliance flexibility. Tables 13 and 14 below summarize the run details and main results.

All four cases result in significant emissions reductions – 48 to 59 percent compared to 2005. Compliance costs do not exceed $13.6 billion in 2030, even without any incremental state energy efficiency investments (Table 14).

In these runs, between 2 and 22 GW of <u>additional</u> CCS retrofits on coal EGUs are deployed compared to the No CPP case. This consistent large deployment of CCS across the runs points to its cost-effectiveness as a source-specific emissions reduction measure. In addition, the disparate policy structures across the runs point to the robustness of this conclusion: While COF-1 imposes

[158] The source-specific CCS-2 achieves 69 percent reduction compared to 2005 at a cost of $39 billion by 2030 (Table 10).

an emissions rate standard on coal EGUs reflecting a certain level of gas co-firing, CPP-2 and CPP-2 impose a system-wide mass-based emissions cap reflecting a system-wide BSER.

These runs are discussed in detail in NRDC' s separate comments in Sections III.C and IV.B.

Table 13: List of NRDC runs where CCS was allowed as a compliance option

Run	BSER specifications	Description	Fossil Emissions Rate Standards/Mass Targets	Trading Level	Incremental Energy Efficiency Deployment (compared to No CPP)
CPP-1	System-wide	2015 CPP targets implemented on existing and new coal and gas EGUs	2025: 1,841,855,097 short tons 2030: 1,675,969,227 short tons 2035: 1,525,006,268 short tons	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	None
CPP-2	System-wide	Updated mass-based targets for existing fossil fuel EGUs based on the CPP methodology 100 lbs/MWh rate enforced on new NGCC units	2025: 1,191,723,942 short tons 2030: 925,488,413 short tons 2035: 760,962,359 short tons 100 lbs/MWh rate enforced on new NGCC units	National-level trading among existing-only fossil resources; National-level trading among new sources is also allowed	None
COF-1	Source-specific	Rate targets based on the application of 60% gas co-firing on all coal EGUs	2025: 1,945 lbs/MWh 2030: 1,730 lbs/MWh 2035: 1,652 lbs/MWh No standard on NGCC units	Facility-level emissions averaging only	None

Table 14: Emissions, compliance costs and benefits results

Run	2030 Carbon Emissions (million short tons)	% Reduction from 2005	Reduction in NOx and SO2 Emissions compared to No CPP, in 2030	Total System Compliance Costs (2016$ billions)	Climate and Health Benefits (2016$ billion)	Benefits/Costs Multiplier	CCS retrofits by 2030	2030 Carbon Price (2012 $/ton)
No CPP	1,710	36%	-	-	-	-	8.2 GW coal retrofits	-
CPP-1	1,669	37%	2% reduction in NOx; 3% reduction in SO2	$1.6 billion	$3 - $6	1.9 – 3.8	10 GW coal retrofits	$0/ton
CPP-2	1,090	59%	39% reduction in NOx; 51% reduction in SO2	$13.6 billion	$56 - $101 billion	4 – 7.4	29 GW coal retrofits	$21.8/ton
COF-1	1,384	48%	16% reduction in NOx; 28% reduction in SO2	$8.4 billion	$30 - $54 billion	3.6 – 6.4	25 GW coal retrofits	-

As discussed above, the 45Q tax credits and revenues from the sales of carbon for EOR applications significantly lower the costs of CCS retrofits, making the technology a favorable compliance option (Table 15). In fact, CCS costs make up a small portion of total system costs by 2030, with an upper bound of 5 percent (Table 16); despite the large CCS deployment across those runs- reaching 29 GW by 2030 in the CPP-2 run - 45Q subsidies and revenues from carbon sales largely offset the costs of carbon capture and transportation (Table 15).

Table 15: Percent reduction in total carbon capture and transportation costs owing to 45Q tax credits and EOR payments

	2020	2025	2030	2035
No CPP		-72%	-72%	-66%
CPP-1		-72%	-84%	-77%
CPP-2		-57%	-61%	-55%
COF-1		-60%	-60%	-54%

Table 16: Total CCS costs[159] as a percentage of total system costs

	2020	2025	2030	2035
No CPP		1%	1%	1%
CPP-1		1%	1%	1%
CPP-2		6%	5%	5%
COF-1		4%	5%	5%

As mentioned above, while emissions rate targets in COF-1 are based on gas co-firing on coal EGUs, 17 GW of additional coal CCS retrofits occur by 2030 compared to the No CPP case: in fact, coal CCS generation exceeds generation from coal EGUs that co-fire with gas. By 2030, coal CCS generation is six times higher than generation from coal EGUs that co-fire with gas (Figure 14). Thus, it is worth reiterating that CCS comes out as an important compliance option under both the rate-based, co-firing approach and the system-wide mass-based scenarios; this further demonstrates that CCS is a cost-effective emission reduction method and that it would be arbitrary to exclude it from consideration at BSER in favor of a heat rate improvement only approach.

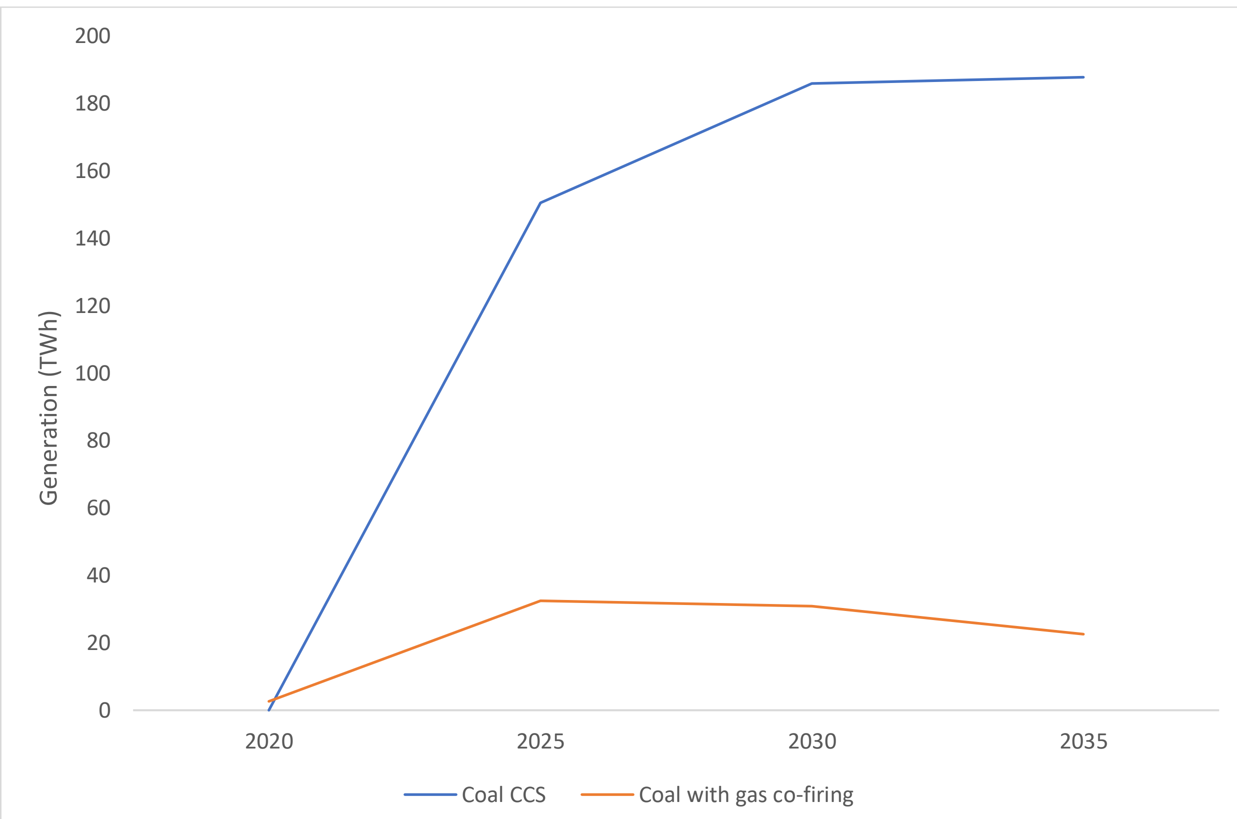

Figure 14: Coal CCS generation vs. coal co-firing – COF-1

[159] Total CCS costs include the following elements: levelized capital costs of the CCS retrofit; VOM, FOM and fuel costs for the retrofitted plant; carbon transportation and storage costs; and 45Q payments.

The modest system compliance costs and large emissions reductions across the three runs confirm that CCS retrofits are a cost-effective source-specific resource**.** These runs also illustrates what a lower level CCS target would achieve. This is because the same target emission rate could be designed based on a certain level of CCS deployment and, more importantly, because once the emission rate is imposed, the IPM model treats the system the same way regardless of how the specific emission rates were designed. **EPA must conduct a thorough analysis of the potential reductions that can be achieved through various levels of CCS deployment and of the climate, health and other benefits of such an approach. As noted, a system-based approach remains preferable as it enables greater emission reductions at lower costs. EPA should also model the emission reductions under a national, category-specific emissions averaging trading scheme in order to ensure that CCS is deployed in the most cost-effective manner.**

In conclusion, the NRDC modeling runs consistently show that large levels of CCS deployment can achieve significant emissions reductions at reasonable costs. **EPA should build on the NRDC modeling and, if it does not adopt a system-based approach, must consider CCS as a source-specific emissions reduction measure in the BSER.**

VII. Conclusion

Carbon capture and sequestration meets the Clean Air Act section 111(d) criteria better than minimal heat rate improvements and EPA must meaningfully consider the technology and engage with the massive record underlying the Clean Power Plan. These comments demonstrate that CCS has the potential to reduce emissions from the affected sources by significantly reducing emissions at costs that are not exorbitant.

If the Agency insists on its "inside-the-fence" approach to BSER, it must choose the *best* system as demanded by this technology-forcing statute and include carbon capture and sequestration.

Respectfully submitted,

John Thompson, Director, Fossil Transition Project **Clean Air Task Force** (618) 457-0137 jthompson@catf.us James Duffy, Associate Attorney Bruce Hill, Chief Geoscientist Deepika Nagabhushan, CCS Policy Associate Conrad Schneider, Advocacy Director	**Natural Resources Defense Council** Ben Longstreth, Senior Attorney, Climate and Clean Energy Program Starla Yeh, Director, Policy Analysis Group, Climate and Clean Energy Program Rachel Fakhry, Policy Analyst, Climate and Clean Energy Program George Peridas, Ph.D. Senior Scientist, Climate & Clean Energy Program

Appendix Index

A. CCS Costs
B. Technical Appendix on Carbon Capture and Sequestration
C. NRDC + CCS Cost Assumptions

Attachments Index

A. Timothy C. Grant, *An Overview of the CO_2 Pipeline Infrastructure*, (Oct. 18, 2018).
B. Bala Suresh, *Global Market for Carbon Dioxide*, (Feb. 2017).
C. Corwyn Bruce, *et al.*, *Post combustion CO2 capture retrofit of SaskPower's Shand Power Station: Capital and operating cost reduction of a 2nd generation capture facility*, presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018.
D. David Greeson, "Petra Nova Capture Project" presented at International CCS Knowledge Centre Symposium on Carbon Capture, GHGT-14, October 21-25, 2018.
E. Email from Serpil Kayin to John Thompson (Aug. 23, 2018).
F. Shayegh *et al.*, *Evaluating relative benefits of different types of R & D for clean energy technologies*, 107 Energy Policy 532 (2017).
G. CATF National Comparisons, August 2018 Modeling Results.
H. Comment submitted by CATF & Partial Carbon Capture and Storage Retrofit Technical Appendix (Modified and Reconstructed Sources), Doc. No. EPA-HQ-OAR-2013-0603-0280 (Oct. 16, 2014).
I. Supplemental comment submitted by CATF & Technical Appendix (New Source Performance Standards) Doc. No. EPA-HQ-OAR-2013-0495-9664 (May 9, 2014).
J. Comment submitted by CATF (Clean Power Plan) & Attached Apps. and Exs., Doc. No. EPA-HQ-OAR-2013-0602-25574.
K. Xijia Lu, "Flexible Integration of the sCO2 Allam Cycle with Coal Gasification for Low-Cost, Emission-Free Electricity Generation," presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018.
L. Amy L. Clarke *et al.*, Application of material balance methods to CO_2 storage capacity estimation within selected depleted gas reservoirs, 23 Petroleum Geoscience 339 (2017).
M. David L. Carr *et al.*, CO_2 Sequestration Capacity Sectors in Miocene Strata of the Offshore Texas State Waters, 5 Gulf Coast Association of Geological Societies Journal 130 (2016).