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Re: Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, Proposed Rule, 83 Fed. Reg. 65,424 (Dec. 20, 2018)

Clean Air Task Force (CATF), Natural Resource Defense Council (NRDC), Conservation Law Foundation (CLF), Clean Wisconsin and Minnesota Center for Environmental Advocacy (MCEA) submit the enclosed comments on the U.S. Environmental Protection Agency's (EPA's) above-captioned Proposal to revoke the current 1,400 lbs. CO_2/MWh standard for new coal-fired power plants and replace it with standards of 1,900 – 2,200 lbs. CO_2/MWh. The Proposal is based on the Agency's determination that "the most efficient demonstrated steam cycle," not partial carbon capture and sequestration, is the best system of emission reduction for new coal-fired power plants. We vigorously oppose this Proposal, which has no basis in the record and fails to fulfill the Clean Air Act's statutory mandate, as explained in detail in the enclosed comments.

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

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living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

CLF protects New England's environment for the benefit of all people. We use the law, science and the market to create solutions that preserve our natural resources, build healthy communities, and sustain a vibrant economy.

Since 1970, Clean Wisconsin has been the voice for the environment, working for clean air, clean water and clean energy and to protect the places we all love. To achieve this, we work on a wide range of issues and in a number of venues to protect our natural resources and the health of all Wisconsinites, now and for generations to come.

MCEA's mission is to use law, science and research to protect Minnesota's environment, natural resources and the health of its people.

Our organizations also join the comments submitted to this docket today by "Joint Environmental and Public Health Commenters" pertaining to EPA's basis for regulating carbon pollution from electric generating units under section 111 of the Clean Air Act; and concerning climate science and climate change. CATF, et al. submit separate comments today on the treatment of biomass in this rulemaking.

Respectfully submitted,

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I. Introduction

The Clean Air Act requires "maximum feasible control of new sources at the time of their construction"[1] to promote public health and welfare and prevent air pollution.[2] Section 111(b) of the Act, in particular, is forward-looking and technology-forcing and requires the Administrator to base standards of performance for new stationary sources on the *best* system of emission reduction.

Four years ago the U.S Environmental Protection Agency (EPA or Agency) found that carbon capture and storage (CCS) "technology has been demonstrated to be technically feasible and is in use or under construction in various industrial sectors, including the power generation sector."[3] The Agency set the current standard of 1,400 lbs. CO_2/MWh-g for new coal-fired power plants based on post-combustion partial-CCS, and concluded that the standard is achievable for "all fuel types, under a wide range of conditions, and throughout the United States."[4]

The robust record underlying the current standard has only been bolstered in the intervening years by declining costs and expanded geographic availability. Despite these facts and the statutory mandate, the Agency proposes to significantly weaken the current standards based "primar[ily on] the high costs and limited geographic availability of CCS."[5] The Proposal is designed to accommodate the building of a new coal plant anywhere in the country under the most unfavorable possible circumstances, allowing those new plants to emit significantly more health-harming pollution than permissible under the current standard. The Agency proposes to find that the best system of emission reduction is "the most efficient demonstrated steam cycle,"[6] and that the standard for new power plants is 1,900 to 2,200 lbs. CO_2/MWh-g[7] – worse than the rates existing plants are currently achieving.

According to EPA, the proposed standards would allow a new 600 MW plant to emit 1.1 million additional tons of CO_2 per year and 500 additional tons of SO_2 per year, compared to the current standards.[8] Over the course of an average 48-year lifetime, that new plant would emit at least 52.8 million additional tons of CO_2 and 24,000 additional tons of SO_2.[9] To put this in context, EPA claims that the *entire* ACE Proposal, covering *all* existing fossil fuel-fired power plants would reduce

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1 S. Rep. No. 91-1196, at 16 (1970).
2 42 U.S.C. § 7401.
3 Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510, 64,513 (Oct. 23, 2015) (codified at 40 C.F.R. pt. 60 subpart TTTT).
4 80 Fed. Reg. at 64,513.
5 Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 Fed. Reg. 65,424, 65,426 (proposed Dec. 20, 2018) (to be codified at 40 C.F.R. pt. 60).
6 83 Fed. Reg. at 65,424.
7 *Id.* at 65,427.
8 EPA, EPA 452/R-18-005, *Economic Impact Analysis for the Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, at 2-4 to 2-6 tbls. 2-1, 2-6, & 2-7 (2018) [hereinafter 2018 EIA].
9 *Id.*

SO_2 emissions by 1,000 tons and CO_2 emissions by 7 million tons by 2035.[10] If this rule is finalized, only *one* new coal plant complying with the weakened standards would negate any emission reductions forecasted to occur under the ACE rule many times over.

In fact, in 2015 EPA rejected an efficient steam cycle as the best system, in part because it fails to significantly reduce CO_2 emissions as compared to business as usual or provide an incentive for technological innovation.[11] The Agency emphasized that a "highly efficient 500 MW coal-fired SCPC with partial-CCS would emit about 675,000 fewer metric tons of CO[2] each year than that from a new, less efficient coal-fired utility boiler with an assumed emission of 1,800 lb CO[2] /MWh-g."[12] Remarkably, in 2015 EPA assumed that the uncontrolled baseline would be *better* than the standard EPA now proposes as the *best* system of emission reduction.

The Proposal is counter to the purpose and requirements of the Clean Air Act. It fails to overcome the robust record underlying the current standard, which has only strengthened since finalization. And it does not display the type of reasoned decision-making demanded from expert agencies. EPA bears the burden of justifying why the existing environmentally-protective standards should be replaced with a standard that would increase emissions; harming public health and damaging the climate. This Proposal does not meet that burden and must not be finalized.

II. If finalized as proposed, this rulemaking would not comport with the Clean Air Act or the requirements for reasonable decision-making.

As Commenters submitted today in joint comments on this topic, EPA has not provided sufficient notice or rationale to upend it's 2015 decision to properly regulate CO_2 from new fossil-fired power plants, nor is there any reasonable basis to do so.[13] EPA must control CO_2 emissions from fossil fuel-fired power plants in accordance with the Clean Air Act and the Administrative Procedures Act (APA).

A. EPA must ground its action in the Clean Air Act, which demands that emission standards are based on the *best* system of emission reduction.

An administrative agency is "a creature of the statute" it is directed to implement, and only has the powers "specifically conferred upon it by statute."[14] Agency decisions that are made on pure policy grounds, divorced from statutory factors, therefore are invalid.[15] EPA's indication that the "purpose

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[10] *Id.* at ES-10 tbl. ES-8.
[11] *See generally* 80 Fed. Reg. at 64,594-96.
[12] *Id.* at 64,574.
[13] *See* Joint Comments of Environmental and Public Health Organizations submitted today focusing on EPA's basis for regulating carbon pollution from electric generating units under section 111 of the Clean Air Act.
[14] *Int'l Union of Elec., Radio & Mach. Workers, AFL-CIO v. NLRB*, 502 F.2d 349, 354 (D.C. Cir. 1974).
[15] *See API v. EPA*, 706 F.3d 474, 479 (D.C. Cir. 2013) ("EPA expressly viewed the data… toward 'promoting growth' in the cellulosic biofuel industry….[S]uch a purpose has no basis in the relevant text of the Act."); *see also Whitman v. Am. Trucking Ass'n*, 531 U.S. 457, 471 (D.C. Cir. 2001) (barring consideration of cost because it is unambiguously precluded in the statute); *see also Sierra Club v. Costle*, 657 F.2d 298, 409 (D.C. Cir. 1981) ("Political considerations are improper when they force an agency to make decisions based on factors not relevant to the applicable statute."); *cf. Massachusetts v. EPA*, 549 U.S. 497, 532 (2007).

of this regulatory action"[16] is to comply with Executive Order 13,783's demand to review all agency actions "that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources"[17] renders the Proposal suspect from the outset.

The Clean Air Act does not authorize regulatory protection for highly-polluting sources of electricity for political reasons. Instead, the Act requires EPA to identify the *best* system of emission reduction that is adequately demonstrated, considering costs and health, environmental, and energy impacts, and set a standard that "reflects the degree of emission limitation achievable through the application of" that system.[18] The purpose of section 111(b) is to "prevent new pollution problems, and towards that end, maximum feasible control of new sources at the time of their construction is…the most effective, and in the long run, least expensive approach."[19] It is the section 111 statutory factors, as well as the Clean Air Act's purpose, which must guide this rulemaking, not a direction to alleviate burdens on fossil fuel-fired power plants.

EPA and the courts have extensive experience with interpreting section 111 and there is significant precedent and caselaw in place to ensure that the standards are based on the *best* system of emission reduction. Section 111 is technology-forcing and "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present."[20] The Senate Report to the section that became 111(b) makes clear that Congress had *not* intended that the technology "must be in actual routine use somewhere," but was instead concerned with whether the technology would be available to for installation in new plants.[21] The House Report similarly suggests that new source standards were "intended to create incentives for improved technology, which could achieve greater or equivalent or lower cost, energy demand, and environmental impacts."[22]

The courts have held that an "adequately demonstrated" system is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[23] EPA may "hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."[24] The balancing of factors mandated by section 111 "embraces consideration of technological innovation as part of that balance."[25] Therefore, EPA's system of emission reduction must look at what is the best system available for the *next* likely coal-fired power plant, not antiquated technology which has been in use for decades.

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16 83 Fed. Reg. at 65,429.

17 Exec. Order No. 13,783 § 2(a) (Mar. 28, 2017).

18 42 U.S.C. § 7411(a)(1).

19 S. Rep. No. 91-1196, at 16 (1970).

20 *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); *see also* 83 Fed. Reg. at 65,433 (quoting same).

21 *Portland Cement Ass'n*, 486 F.2d at 391 (quoting S. Rep. No. 91-1196, at 16 (1970)); 83 Fed. Reg. at 65,433 (quoting same)).

22 H. Rep. No. 95-294, at 186 (1977); *see also* S. Rep. 91-1196, at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources.").

23 *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *see also* 83 Fed. Reg. at 65,433 (quoting same).

24 *Sierra Club*, 657 F.2d at 364.

25 *Id.* at 346.

Under section 111, maximum feasible control is required even if the standard cannot be met by every new source in the source category that would have been constructed in the absence of the standard. "It is the system which must be adequately demonstrated and the standard which must be achievable. This does not require that a … plant be currently in operation which can at all times and under all circumstances meet the standards"[26]

In addition, "the amount of air pollution [is] a relevant factor to be weighed when determining the optimal standard."[27] The Proposal entirely fails to grasp the gravity of climate change, the source category's contribution or the Clean Air Act's mandate to regulate these dangerous emissions to the maximum degree feasible to protect public health and the environment.

B. Agencies must engage in reasoned decision-making.

Under both the Clean Air Act and the Administrative Procedure Act, a final rule must be the result of an agency's reasoned decision-making, that is "it weighed competing views, selected a [solution] with adequate support in the record, and intelligibly explained the reasons for making that choice."[28] A rule will be reversed if it is "arbitrary, capricious, an abuse of discretion or otherwise not in accordance with the law."[29] *Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance* provides the seminal test for reasoned decision-making under the APA:

> [T]he agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made. In reviewing that explanation, we must consider whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment. Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.[30]

To comply with the APA and Clean Air Act,[31] the agency must examine the relevant data and show that the data is accurate and defensible.[32] Agencies must use "the best information available,"[33] and decisions must exhibit a "rational relationship" with "known behavior."[34] A "vaporous record will

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[26] *Essex Chem. Corp.*, 486 F.2d at 433.
[27] *Sierra Club*, 657 F.2d at 326, 347; *see also* 83 Fed. Reg. at 65,433 (quoting same).
[28] *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 784 (2016).
[29] *See* 42 U.S.C. § 7607(d)(9); 5 U.S.C. § 706(1); *Catawba County v. EPA*, 571 F.3d 20, 41 (D.C. Cir. 2009) (explaining that the same standard is applied under both Acts).
[30] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal citations omitted); *see also Encino Motorcars, LLC v. Navarro*, 136 S.Ct. 2117, 2125-26 (2016) (same).
[31] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 523 (D.C. Cir. 1983) ("At a minimum, failure to observe the basic APA procedures, if reversible error under the APA, is reversible error under the Clean Air Act as well.").
[32] *See Dist. Hosp. Partners v. Burwell*, 786 F.3d 46, 57 (D.C. Cir. 2015).
[33] *Catawba County*, 571 F.3d at 45.
[34] *Chem. Mfrs. Ass'n v. EPA*, 28 F.3d 1259, 1265 (D.C. Cir. 1994); *see also API v. EPA*, 862 F.3d 50, 68 (D.C. Cir. 2017) (same).

not do—the APA requires reasoned decisionmaking grounded in actual evidence."[35] Nor will a court defer to a decision, which lacks coherence,[36] or fails to consider "significant and viable and obvious alternatives."[37]

Regulations, like those under review in this Proposal, that have been promulgated after extensive study and public outreach produce significant reliance interests. If an agency changes course, it 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."[38] "An agency cannot simply disregard contrary or inconvenient factual determinations that it made in the past."[39] "It follows that an unexplained inconsistency in agency policy is a reason for holding an interpretation to be an arbitrary and capricious change from agency practice."[40]

"Courts look closely to determine whether the facts provide an adequate basis for an agency prediction that it can continue to protect the intended beneficiaries of legislation despite deregulation."[41] The purpose of the Clean Air Act is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.[42] Therefore, the Agency should "err on the side of overprotection" not open the country to the potential for massive increases in pollution, as this Proposal would.[43]

C. Finalizing this Proposal would be contrary to the statute and would not be reasoned decision-making.

This Proposal is unlawful because it fails to meet the requirements of Clean Air Act section 111 or further the purposes of the Act generally. As described in detail *infra*, the Proposal brushes the comprehensive record supporting the current standard aside, leaving "unexplained inconsistencies,"[44] and fails to update the record to reflect interim developments or support its policy changes.

The Proposal fails to comply with the technology-forcing, forward-looking[45] mandate of section 111(b) in discounting CCS. As we demonstrate in detail in Part III below, CCS continues to be the *best* system of emission reduction:[46] it is adequately demonstrated by numerous projects, its costs are reasonable and declining, and the technology continues to improve, providing an avenue for significant emission reduction.

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[35] *Flyers Rights Educ. Fund v. FAA*, 864 F.3d 738, 741 (D.C. Cir. 2017).
[36] *See Tripoli Rocketry Ass'n v. Bureau of Alcohol, Tobacco, Firearms, and Explosives*, 437 F.3d 75, 77 (D.C. Cir. 2006).
[37] *Nat'l Shooting Sports Found. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013).
[38] *FCC v. Fox Television Stations*, 566 U.S. 502, 515-16 (2009) (citation omitted).
[39] *Id.* at 537 (2009) (Kennedy, J., concurring).
[40] *Encino Motorcars*, 136 S.Ct. at 2126 (citation omitted).
[41] Merrick B. Garland, *Deregulation and Judicial Review*, 98 HARV. L. REV. 507, 535-36 (1985).
[42] 42 U.S.C. § 7401(b)(1).
[43] *NRDC v. EPA,* 902 F.2d 962, 972 (D.C. Cir. 1990); *see also State Farm*, 463 U.S. at 55 ("Congress intended safety to be the pre-eminent factor under [the Act]").
[44] *Fox Television Stations*, 566 U.S. at 515-16.
[45] *Portland Cement*, 486 F.2d at 391; *Sierra Club*, 657 F.2d at 346.
[46] 42 U.S.C. § 7411.

Moreover, as described in Part III.E., the current 1,400 lbs. CO_2/MWh standard is achievable through a variety of means. In proposing to regulate to the lowest common denominator, EPA fails to recognize that section 111 requires maximum feasible control,[47] not that every plant "can at all times and under all circumstances meet the standards."[48]

Perhaps most egregiously, the Proposal fails to account for emissions impacts at all.[49] As we discuss in Part III.D., CCS meaningfully reduces emissions. And in Part V we demonstrate that the proposed standard is entirely inadequate, backward-looking, and fails to require *any* emission reduction, never mind the maximum feasible control of new sources.

In addition, the Proposal represents arbitrary, capricious and unreasonable decision-making. As we establish throughout Part III, CCS remains the best system and this Proposal has not offered sufficient technical or factual justification for its change of position.

For example, as described in Parts III.A. and III.C., EPA fails to update the robust record underlying the current standard with "relevant data"[50] on CCS projects or its associated costs. EPA then bases its Proposal on that incomplete record, which fails to overcome the previous record.[51] The Proposal ignores "important aspect[s] of the problem,"[52] including the realities[53] of climate change, the electric market, and the state of CCS, including 45Q tax incentives, enhanced oil recovery revenues, and declining costs. The Proposal also fails to consider "significant and viable alternatives"[54] available for new sources to meet the standard, such as building an integrated gasification combined cycle (IGCC), utilizing transmission lines and pipelines to reach storage opportunities (as discussed in Part III.E.), or co-firing with natural gas (as discussed in Part IV). At every turn, EPA fails to further the purpose of the Clean Air Act[55] or "articulate a satisfactory explanation" for the Proposal, which exhibits "a rational explanation between the facts found and choice made."[56]

Finalization of this Proposal would constitute an unjustified reversal, untethered to statutory mandates, and would therefore, be arbitrary, capricious and unlawful.

III. CCS is the best system of emission reduction.

CCS, the best system of emission reduction underlying the current standards for new coal-fired power plants, is composed of three separate technologies: 1) carbon capture, 2) transportation, and

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47 S. Rep. No. 91-1196, at 16 (1970).
48 *Essex Chem.*, 486 F.2d at 433.
49 *Sierra Club*, 657 F.2d at 326, 347.
50 *State Farm*, 463 U.S. at 43.
51 *Fox Television Stations*, 566 U.S. at 537 (Kennedy, J., concurring).
52 *State Farm*, 463 U.S. at 43.
53 *Chem. Mfrs. Ass'n*, 28 F.3d at 1265; *see also API*, 862 F.3d at 68 (same).
54 *Nat'l Shooting Sports*, 716 F.3d at 215.
55 *NRDC*, 902 F.2d at 972; *see also State Farm*, 463 U.S. at 55 (1983) ("Congress intended safety to be the pre-eminent factor under the Act").
56 *State Farm*, 463 U.S. at 43.

3) injection and storage of CO_2 deep underground. These technologies are available, demonstrated, cost reasonable and have been in wide commercial use for decades.[57]

Since the 1930s, carbon capture equipment has been used commercially to purify natural gas, hydrogen, and other gas streams found in industrial settings.[58] Since that time, the technology has become more readily available and cost-effective. 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.[59] In the U.S., over 23 million tonnes of CO_2 is captured from natural gas processing plants, refineries, and fertilizer plants and sold for enhanced oil recovery (EOR).[60] Since the 1970s, over 850 million tonnes of CO_2 have been injected underground in the U.S. for EOR.[61] Another approximately 12.5 million tonnes/year in the U.S. supplies the food industry, beverage carbonation, and other specialty applications.[62]

A mature network of over 5,237 miles of pipelines brings CO_2 to EOR fields in the U.S., [63] 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 U.S. also has a strong 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.[64] EPA regulates the injection of CO_2 through the Safe Drinking Water Act's Underground Injection Control Program (UIC) and the Clean Air Act's Greenhouse Gas Reporting Program (GHGRP). Many states, particularly with active oil and gas industries, have their own regulations that govern the reporting of CO_2 injection for state tax and safety purposes. These include California, Montana, North Dakota, Wyoming, Kansas,

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[57] CATF & NRDC, Comments on Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, Specific to Carbon Capture and Sequestration, Doc. ID EPA-HQ-OAR-2017-0355-24266 (Oct. 31, 2018).

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

[59] 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.

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

[61] 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.

[62] CATF & NRDC, Comments, *supra* note 57, at Attach. B (Bala Suresh, *Global Market for Carbon Dioxide*, at 26 (Feb. 2017)).

[63] Pipeline & Hazardous Materials Safety Admin., *Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems (last visited Feb. 27, 2019).

[64] Matthew Wallace et al., 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.

Oklahoma, Texas, Louisiana, and Mississippi.[65] IRS guidelines and requirements govern tax credits for CO_2 storage.[66]

Now the experience garnered by non-utility industries using CO_2 capture, transport, and storage over the last 50-80 years is migrating to the power sector as part of efforts to address climate change. As of 2017, at least 21 states had enacted legislation related to CCS.[67] Montana, for example, requires all new coal plants to capture and sequester at least 50 percent of their CO_2.[68] New York has adopted regulations requiring existing coal plants to either retrofit with CCS or cease operations by 2021.[69] And in Canada, existing coal plants must either close or install CCS by 2030.[70]

In 2015, EPA concluded that "CCS technology has been demonstrated to be technically feasible and is in use or under construction in various industrial sectors, including the power generation sector."[71] Therefore, the Agency based the current standard of 1,400 lbs. CO_2/MWh-g on post-combustion capture and sequestration in deep saline formations.[72] A plant burning bituminous coal can meet the standard by capturing and storing 16 percent of its CO_2, while a plant burning sub-bituminous coal or dried lignite can meet it by capturing and storing 23 percent of its CO_2.[73] The new plant also has the option to co-fire with natural gas or build an IGCC to meet the standard.[74] The Agency concluded that the standard is achievable and cost reasonable, under conservative assumptions, for "all fuel types, under a wide range of conditions, and throughout the United States."[75]

As described above, while an Agency may change course, it must root its choices in the underlying statute and provide good reasons for the new policy, which address underlying facts, science, circumstances, the record, and the agency's past reasoning.[76] "An agency cannot simply disregard contrary or inconvenient factual determinations that it made in the past."[77] The current standard is based on nearly 800 supporting documents,[78] tens of public listening sessions, a 120-day comment

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[65] *See Rules for CO2 Injection*, CTR. FOR CLIMATE AND ENERGY SOLS., https://www.c2es.org/document/rules-co2-injection/ (last updated May 2017) (describing state legislation specifying requirements applicable to CO_2 injection for EOR and geologic storage).
[66] 26 U.S.C. § 45Q; IRS, *Credit for Carbon Dioxide Sequestration under Section 45Q* (2009), https://www.irs.gov/pub/irs-drop/n-09-83.pdf.
[67] Megan Cleveland, Nat. Conference of State Legislatures, *Carbon Capture and Sequestration* (2017), https://www.wyoleg.gov/InterimCommittee/2017/09-0629APPENDIXG-1.pdf.
[68] MONT. CODE ANN. § 69-8-421(8).
[69] N.Y. State Register May 16, 2018, *Rule Making Activities*, N.Y. STATE DEP'T OF STATE, at 5 (2018), https://docs.dos.ny.gov/info/register/2018/may16/pdf/rulemaking.pdf. 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.
[70] 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=.
[71] 80 Fed. Reg. at 64,513.
[72] *Id.*
[73] *Id.*
[74] *Id.*
[75] *Id.*
[76] *See generally*, William W. Buzbee, *The Tethered President: Consistency and Contingency in Administrative Law*, 98 B.U. L. REV. 1358 (Oct. 2018).
[77] *Fox Television Stations*, 566 U.S. at 537 (Kennedy, J., concurring).
[78] EPA, Supporting Documents, Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, Docket EPA-HQ-OAR-2013-0495,

period and the receipt of over two million comments.[79] Not only does EPA fail to overcome the robust record, based on unprecedented stakeholder engagement supporting CCS as the best system of emission reduction, but it also fails to account for the significant CCS developments that have occurred in the four years since the current standard was finalized. CCS was the *best* adequately demonstrated and cost reasonable system to reduce dangerous emissions in 2015 and is even more so today.

A. Carbon capture is adequately demonstrated.

"Congress envisioned the scanning of broader horizons and asked EPA to survey related industries and current research to find technologies which might be used to decrease the discharge of pollutants."[80] In 2015, EPA "looked widely at all relevant information and considered all the data, information, and comments that were submitted [and then] re-examined and updated information that was available."[81] In stark contrast, the current Proposal cherry-picks from the previous record, ignores relevant information and fails to update critical information.

EPA's standards have been upheld on the basis of 1) "literature review and operation of one plant in the U.S;"[82] 2) "various test programs;"[83] 3) "pilot plant technology;"[84] 4) "testimony from experts and vendors;"[85] and 5) the operation of international projects.[86] EPA may also base standards upon "the reasonable extrapolation of a technology's performance in other industries."[87] Standards are also reasonable where although "the combination of controls is novel," each of the "components have been tested and used."[88] As we describe in detail below, CCS exceeded this demonstration in 2015[89] and the source category has built on that demonstration since the current rule was finalized.

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https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=postedDate&po=0&dct=SR%2BO&D=EPA-HQ-OAR-2013-0495.

79 80 Fed. Reg. at 64,528-29.

80 *Cf. Kennecott v. EPA*, 780 F.2d 445 (4th Cir. 1985) (discussing EPA's duties under the Clean Water Act's analogous "best available technology" standard inquiry).

81 80 Fed. Reg. at 64,547.

82 *Essex Chem.*, 486 F.2d at 434.

83 *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); *Portland Cement*, 486 F.2d at 392 (if actual tests are not relied on, but instead a prediction is made, its validity as applied to this case rests on the reliability of [the] prediction and the nature of the assumption).

84 *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).

85 *Portland Cement Ass'n*, 486 F.2d at 402.

86 *See Sierra Club*, 657 F.2d at 346 (achievability of standard upheld, even though no domestic source was achieving the promulgated limit, due in part to successful operation of the technology in Japan); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, at 934 n.3 (D.C. Cir. 1978) (section 111 (b) standard of performance justified in part based on data from "foreign boilers burning lignite").

87 *Lignite Energy Council*, 198 F.3d at 934.

88 *Cf. Sur Contra la Contaminacion v. EPA*, 202 F.3d 443, 448 (1st Cir. 2000) (upholding CAA section 145 best available control technology determination); *see also Native Village of Point Hope v. Salazar*, 680 F.3d 1123, 1133 (9th Cir. 2012).

89 *See* Br. of *Amicus Curiae* Carbon Capture and Storage Scientists in Supp. of Resp'ts, at 6-30, *North Dakota v. EPA*, 15-1382, Doc. No. 1652097 (D.C. Cir. Dec. 21, 2016) (Attach. B) (explaining that CCS is adequately demonstrated because CCS projects are operational and under development in the power sector and have been deployed and scaled up in industrial applications, which is transferrable to the power sector).

1. CCS projects

Operational CCS projects range from test- and pilot-scale projects to large-scale, commercial projects, and have been demonstrated domestically and abroad, and on coal-fired power plants and other industrial applications. There are currently 23 large-scale CCS facilities operating or under construction around the world, capturing almost 40 Mtpa.[90] While EPA focused on projects demonstrating full-scale operation within the electric generating industry in 2015, it reviewed the full range of CCS applications.[91] There are currently an additional 28 pilot and demonstration-scale CCS facilities in operation or under construction capturing more than 3 Mtpa of CO_2.[92] In 2015, EPA showed that small-scale CCS projects could be scaled up, CCS technology from other industries could be transferred to the power sector and that the results at currently operating CCS power plants could be replicated and built upon.[93]

The current Proposal fails to explain its departure from the 2015 record or to develop a complete record itself. When the Agency is not entirely turning a blind eye to relevant information, it cherry-picks and mischaracterizes the 2015 record and the available information. EPA's failure to "examine the relevant data"[94] or the "factual determinations that it made in the past"[95] renders the Proposal arbitrary and capricious. The diversity of CCS projects in operation, described below, verify that the technology is adequately demonstrated.

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[90] Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).

[91] EPA based its best system of emission reduction determination in 2015 on facilities and other sources of information with no nexus to Energy Policy Act of 2005 (EPAct05) assistance and therefore are in compliance with the Act's requirements. 80 Fed. Reg. at 64,548; *see also* EPA, Technical Support Document: Effect of EPAct05 on BSER for New Fossil Fuel-Fired Boilers and IGCCs, Doc. ID: EPA-HQ-OAR-2013-0495-1873 (Jan. 8, 2014); and Chloe Kolman, EPA, Memorandum to Section 111(b) Docket re: EPAct05, Doc. ID: EPA-HQ-OAR-2013-0495-11334 (July 29, 2015). Congress wanted to ensure that the technological advances achieved with EPAct05 assistance did not serve as the basis for industry-wide performance standards if they were the only facilities achieving the emission reductions associated with the technology. Therefore, the Act precludes EPA from relying *exclusively* on evidence from facilities receiving EPAct05 assistance in a Clean Air Act section 111 rulemaking. 42 U.S.C. § 15962(i)(1). EPAct05 added similar language to the Internal Revenue Code for facilities receiving a tax credit for a qualifying project. 26 U.S.C. § 48A(g)(1). This approach of considering EPAct05 assisted projects in conjunction with other sources of information has been approved by the only court to consider the matter. *Nebraska v. EPA,* 2014 U.S. Dist. LEXIS 141898, *9 n.1 (D. Neb. Oct. 6, 2014) ("technology might be adequately demonstrated if that determination is based at least in part on non-federally funded facilities"). EPA properly does not propose to revisit or reopen this understanding of EPAct05 stating that "because EPA is considering information about the [EPAct05 supported] project in conjunction with other information that is not from facilities affected by EPAct05, EPAct05 does not preclude the EPA from considering such EPAct05 supported] information." 83 Fed. Reg. at 65,444 nn. 88-89.

[92] Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).

[93] *See generally* 80 Fed. Reg. at 64,549-54; EPA, Technical Support Document: Literature Survey of Carbon Capture Tech., at 37-48, Doc. ID: EPA-HQ-OAR-2013-0495-11773 (July 10, 2015); EPA, EPA-452/R-15-005, *Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, at 2-27 to 2-31 (Aug. 2015) [hereinafter 2015 RIA]; EPA, *Basis for Denial of Petitions to Reconsider the CAA Section 111(b) Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units*, at 6-12 (Apr. 2016) [herineafter Denial of Reconsideration].

[94] *State Farm*, 463 U.S. at 43.

[95] *Fox Television*, 556 U.S. at 537 (Kennedy, J., concurring).

i. Petra Nova

In 2015, EPA saw NRG's Petra Nova CCS project's construction as "a clear indication that the developers have confidence in the technical feasibility of the post-combustion capture system."[96] Since then the retrofitted plant has become operational and adds to the robust record supporting CCS as the best system. Petra Nova began capturing CO_2 on January 10, 2017, after retrofitting NRG's W.A. Parish coal-fired power plant southwest of Houston, in Thompsons Texas.[97] Retrofit CCS projects utilize the exact same technology a new plant would use, and integrating CCS into the design of the source from the outset would avoid "complexities and difficulties" associated with installing CCS at a plant that was not designed to accommodate the technology. [98]

This project was built on time and on budget.[99] The 240 MWe slipstream uses Mitsubishi Heavy Industries (MHI) capture technology to remove 90 percent of the CO_2 or about 1.4 MMtpa[100] - the project is capturing 4,776 MT/day.[101] 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.

The Petra Nova project includes a number of innovative technological advances. Specifically, the project uses amine technology designed to capture CO_2 from low-pressure coal plant flue gas streams that have been scrubbed of virtually all ash, sulfur and nitrogen.[102] The primary amine solvent ingredient used in the process is readily available worldwide and inexpensive, and the process is offered commercially with performance warranties.[103] The solvents have relatively low energy consumption properties and, in addition, the industry is developing more advanced solvents for even better performance.[104] 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.[105] Additionally, efficiency

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[96] 80 Fed. Reg. at 64,551.
[97] NETL, DOE, *Recovery Act: Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project*, https://www.netl.doe.gov/projects/files/FE0003311%20Fact%20Sheet.pdf.
[98] Denial of Reconsideration, at 10.
[99] David Greeson, NRG, *What Do Updated 45Q Tax Credits Mean for Carbon Capture (*Apr. 10, 2018), https://www.naruc.org/default/assets/File/CCS45Q_041018.pdf.
[100] *Recovery Act: Petra Nova Parish Holdings*, *supra* note 97.
[101] Sonal Patel, *Japanese Conglomerates Rejigger Power Sector Strategies*, POWER (Feb. 21, 2019), https://www.powermag.com/japanese-conglomerates-rejigger-power-sector-strategies/?pagenum=3.
[102] *See generally* NRG, *Petra Nova*, https://www.nrg.com/case-studies/petra-nova.html (last visited Mar. 13, 2019); DOE/NARUC, *Carbon Capture, Storage & Utilization Partnership Webinar Summary: Petra Nova and the Future of Carbon Capture* (2017), https://www.naruc.org/default/assets/File/Petra%20Nova%20Surge%20Summary%203_23_17.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; *Recovery Act: Petra Nova Parish Holdings*, *supra* note 97.; Sonal Patel, *Capturing Carbon and Seizing Innovation: Petra Nova is POWER's Plant of the Year*, POWER (Aug. 1, 2017), https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/; MIT, *Petra Nova W.A. Parish Fact Sheet*: *Carbon Dioxide Capture and Storage Project*, CARBON CAPTURE & SEQUESTRATION TECH. (Sept. 30, 2016), https://sequestration.mit.edu/tools/projects/wa_parish.html.
[103] *Id.*
[104] *Id.*
[105] 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

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. MHI notes that, "MHIEng's KM CDR Process™ using KS-1™ has demonstrated that clean coal power generation is technically feasible at commercial-scale."[106]

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 come 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's economics. As Petra Nova notes, the retrofit does not impact the Parish Plant's cost of electricity because the project included a cogeneration unit.[107] However, EPA seems to be discounting the success at Petra Nova because it "has not demonstrated the integration of the thermal load of the capture technology into the EGU steam generating unit."[108] The inquiry, however, is to determine the best system of emission reduction, not whether the thermal load is integrated. EPA fails to explain why this innovative design, which under most scenarios has both performance and cost benefits, as compared to integrated systems, is not the best system to reduce CO_2 emissions from a coal plant.[109] As described above, Petra Nova shows that carbon capture is adequately demonstrated. Specifically, the plant was built on schedule and on budget,[110] the capture equipment is stable, and the system has met all capture efficiency and energy performance guarantees.[111] EPA's integration assertion fails to recognize that the Petra Nova project demonstrates an additional option for capturing CO_2 from new coal plants - not integrating the capture unit directly into the coal plant's steam system. This option can potentially lead to better plant performance and economics, including better dispatch flexibility.[112]

Moreover, integrated CCS systems have been adequately demonstrated for at least ten years as shown by the issued air permit for the Tenaska Trailblazer coal plant in Texas.[113] This air permit was for a proposed new coal plant with 90 percent capture, and with the capture unit completely

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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").

106 Hiroshi Tanaka et al., *Advanced KM CDR Process Using New Solvent*, GHGT-14, at 2 (Oct. 2018), https://www.cfaenm.org/wp-content/uploads/2019/03/GHGT14_manuscript_20180913Clean-version.pdf.

107 Anthony Armpriester, *supra* note 58, at 10.

108 83 Fed. Reg. at 65,444.

109 *See generally* Hari C. Mantripragada et al., *Boundary Dam or Petra Nova – Which is a Better Model for CCS Energy Supply*, 82 INT'L J. OF GREENHOUSE GAS CONTROL 59 (2019) (Attach. C) ("The results presented in this paper indicate that under most design (coal type and plant size), market (fuel and CO_2 selling prices) and policy (CO_2 emissions tax) scenarios, using an advanced gas-fired combined cycle co-generation plant to supply CCS regeneration steam and electricity has both performance and cost benefits compared to the case where steam and electricity are supplied from the primary power plant steam cycle. In this regard, the Petra Nova model for solvent regeneration has several advantages over the Boundary Dam model for deployment at new coal-fired power plants.").

110 David Greeson, *supra* note 99.

111 Hiroshi Tanaka et al., *supra* note 106.

112 Int'l CCS Knowledge Ctr., *The Shand CCS Feasibility Study: Public Report* (Nov. 2018), https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.

113 Tenaska, *Trailblazer Energy Ctr. Receives Final Air Quality Permits* (Dec. 14, 2010), https://www.tenaska.com/trailblazer-energy-center-receives-final-air-quality-permits-december-14-2010/.

integrated into the coal plant.[114] And Boundary Dam's operation, described below, builds on this demonstration.

Further, EPA requests comment on whether the government support Petra Nova received casts doubt on the technical feasibility of CCS.[115] However, as EPA recognized in 2015, the availability of subsidies does not undermine the case for a particular pollution control and is "not unusual. Government subsidies in the form of tax benefits, loan guarantees, low-cost leases, or direct expenditures have supported the development of fossil fuel as well as nuclear, geothermal, wind, and solar energy development."[116] In fact, "[u]ntil the mid-2000s, most of the value of energy-related tax incentives supported fossil fuels."[117] However, in the case of Petra Nova, "[t]he project was originally envisioned as a 60 MW slip-stream demonstration and received [government] funding…on that basis."[118] The project was thereafter expanded to 240 MW "quadrupling the size of the capture project without additional federal investment."[119]

Additionally, as discussed more fully in Part II.A., section 111 is forward-looking and technology forcing. MHI, the vendor for Petra Nova's capture technology, announced that the next version of their capture technology will reduce construction costs by 30 percent and a new solvent will be offered in 2019 that will reduce amine degradation and amine emissions by 30 percent.[120] These construction cost savings arise from several improvements - the flue gas quencher and the absorber are improved to reduce both of their heights by more than 30 percent.[121] These two pieces of equipment account for about 30 percent of the total capital cost of the project. The absorber tower, the pipe rack, heat exchangers/pipe, and pump/pipe systems are all modularized to reduce in-field construction costs and improve quality. Redundancy in pumps, tanks, heat exchangers, tank internals and filtration systems results in 20-50 percent cost savings on these systems. All of these changes together result in a 25 percent reduction in the size of the plot plan.[122] MHI is also introducing a new solvent, KS-21, which the company notes, "provides higher stability and lower volatility."[123] It is this *next* plant and the relevant technological improvements and costs reductions anticipated, which is of the utmost relevance for this rulemaking.

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[114] The project was canceled in 2013, according to the developer, in part because Congress failed to adopt climate legislation that put a price on carbon. Tenaska, *Statement: Tenaska Discontinues its Development Efforts for Clean Coal Projects, Focuses on Ongoing Natural Gas, Renewable Development* (June 21, 2013), https://www.eenews.net/assets/2013/06/25/document_cw_01.pdf. At the time of project cancelation, 45Q tax credits for EOR were only $10/tonne. Today, they can reach been $35/tonne for EOR.
[115] 83 Fed. Reg. at 65,444.
[116] EPA, Response to Comments, Standards for Fossil Fuel-fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6.3-120, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015); EPA, Response to Comments, Legal Issues, at 2.2-10, Doc. ID: EPA-HQ-OAR-2013-0495-11861 (Oct. 23, 2015).
[117] Molly F. Sherlock, Cong. Research Serv., *The Value of Energy Tax Incentives for Different Types of Energy Resources: In Brief*, at 9 (2017), https://fas.org/sgp/crs/misc/R44852.pdf.
[118] 80 Fed. Reg. at 64,551.
[119] EPA, Memo: Review of the Current Status of Carbon Capture and Sequestration Projects, at 21, Doc. ID: EPA-HQ-OAR-2013-0495-11947 (Mar. 2018).
[120] Hiroshi Tanaka et al., *supra* note 106.
[121] *Id.*
[122] *Id.*
[123] *Id.*

ii. Boundary Dam

The SaskPower Boundary Dam project was the first large-scale, post-combustion capture project added to a coal plant. It captures CO_2 from the 110 MW Unit 3 at Boundary Dam Power Station.[124] It began commercial operation on October 2, 2014.[125] The project captures up to 90 percent of the CO_2 from Unit 3 or approximately 0.8-1 Mtpa.[126]

Boundary Dam Unit 3, even in its early years, was achieving a level more stringent than the current 1,400 lbs. CO_2/MWh standard to meet Canada's 925 lbs. CO_2/MWh standard.[127] The unit's emissions rate is now 331 lbs. CO_2/MWh at full load. The captured CO_2 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 for EOR. The remaining CO_2 from the project is sent to a nearby deep saline formation as part of the Saskatchewan Aquistore project where it is injected 3.2 km below ground.[128]

The project utilizes Shell's Cansolv process, which 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.[129] This process separates CO_2 from combustion exhaust gases using a liquid amine solvent.[130] Once absorbed by the solvent, heating removes the CO_2 as a high-stream.[131] For the Boundary Dam project, Shell Cansolv offered process guarantees for steam consumption, CO_2 removed, electricity consumption and critical equipment, solvents, and chemical consumption.[132]

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124 *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 (last visited Mar. 13, 2019); Mike Monea, SaskPower, *SaskPower CCS* (2014), 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.

125 *Id.*

126 *Id.*

127 EPA, Response to Comments, Standards for Fossil Fuel-Fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6.2, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015). The latest Boundary Dam status update for the month of January 2019 shows an approximate power output of 115 MW, an online time of 84 percent, and a volume of captured CO_2 of 51,346 tonnes. SaskPower, *BD3 Status Update: January 2019* (Feb. 13, 2019), https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-january-2019. For the month of December 2018, Boundary Dam Power Station's power output was approximately 105 MW, with an online time of 86 percent and 70,395 tonnes CO_2 captured. SaskPower, *BD3 Status Update: December 2018* (Jan. 11, 2019), https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-december-2018.

128 *Id.*

129 Cansolv Techs. Inc., Shell Glob. Sols. Int'l BV, *Cansolv Technologies Inc. CO_2 Capture System* (2012), http://s02.static-shell.com/content/dam/shell-new/global/downloads/pdf/factsheet-cansolvco2.pdf.

130 *Id.*

131 *Id.*

132 John Sarlis, Cansolv Techs. Inc., *Providing the Capture Process* (2013), https://www.yumpu.com/en/document/view/24417751/sk-ccs-symposeum-john-sarlis-cx-cansolv-revised.

In 2015, EPA found that "the project clearly shows the technical feasibility of full-scale, fully integrated implementation of available post-combustion CCS technology."[133] And further that "[t]he experience at Boundary Dam is directly transferrable to other types of post-combustion sources, including those using different boiler types and those using different coal types."[134]

Boundary Dam was a retrofit which "poses special complexities and difficulties that a new source would not experience."[135] As described above, the very purpose of section 111 is to "prevent new pollution problems, and towards that end, maximum feasible control of new sources *at the time of their construction* is…the most effective, and in the long run, least expensive approach."[136] The Shell Cansolv capture unit's operation experienced some initial difficulties due to the low-rank coal creating fly ash and other contaminant challenges for the solvent, causing premature solvent degradation.[137] Some generic equipment problems, unrelated to the CCS portion of the project, also caused periods of downtime early on.[138] But despite these challenges, the facility still captured 415,000 tonnes of CO_2 between October 2014 and September 2015 – exceeding a 40 percent capture rate.[139] In fact, this capture rate would have satisfied the current standard for a plant with five times the volume of emissions.[140]

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.[141] The improvements were successful, and by October 2017, the plant had achieved design capacity and the ability to maintain 85 percent operational availability for on-going future operation.[142] The unit experienced downtime during the summer of 2018, but that was related to damage caused by a severe storm – outside of this downtime, the unit was 94 percent available.[143] By the end of January 2019, the unit had captured 2,516,679 tonnes of CO_2 since commencing operation and achieved a high capture rate, including a peak one-day rate of 2,580 tonnes for the month of January.[144]

Michael Monea, President of Carbon Capture Initiatives at SaskPower until 2016, and now President and CEO of the International CCS Knowledge Centre, stated that, "post-combustion capture has

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133 80 Fed. Reg. at 64,550.
134 *Id.*
135 Denial of Reconsideration, at 10.
136 S. Rep. No. 91-1196, at 16 (1970) (emphasis added).
137 Br. of *Amicus Curiae* Saskatchewan Power Corp. in Supp. of Resp'ts, at 7-10, *North Dakota v. EPA*, 15-1381, Doc. No. 1652427 (D.C. Cir. Dec. 21, 2016) (Attach. D) (describing initial issues at Boundary Dam and their resolution).
138 Denial of Reconsideration, at 8; *see also* Br. of *Amicus Curiae* Saskatchewan Power Corp., *supra* note 137, at 7-10 (describing initial issues at Boundary Dam and their resolution).
139 Denial of Reconsideration, at 9.
140 *Id.*
141 Michael Monea, *An Update Report on the Integrated CCS Project at SaskPower's Boundary Dam Power Station*, GHGT-14 (Oct 22, 2018) (Attach. E).
142 *Id.*
143 SaskPower, *BD3 Status Update: December 2018* (Jan. 11, 2019), https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-december-2018.
144 SaskPower, *BD3 Status Update: January 2019* (Feb. 13, 2019) https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-january-2019.

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."[145] Now that the initial start-up issues have been resolved, "[t]he focus for SaskPower is shifting to the economics of the CCS facility, by getting costs as low as possible, so that the Crown corporation can present the best information possible to decision-makers when they determine the future use of CCS across the rest of SaskPower's coal-generating fleet."[146]

As section 111 is forward-looking and technology-forcing, the initial issues associated with Boundary Dam have limited relevance to this rulemaking, especially because Boundary Dam met the current standard during its initial startup anyhow. Regardless, the improvements and repairs SaskPower made in the intervening years and its current operation are more important because they represent learnings that a new plant would not have to go through. As explained below, these learnings have been documented and built upon in the recent Shand Report,[147] which concludes that the next plant would cost 67 percent less.

iii. Other domestic CCS projects

In 2015, EPA reviewed several pilot-scale CCS projects and projects in other industries.[148] The Agency demonstrated that the projects could be scaled up[149] and that the technology could be transferred to the power industry.[150] In the preamble to the current Proposal, EPA fails to consider any projects other than Petra Nova and Boundary Dam. This is not the type of broad and in-depth investigation section 111 demands.[151]

AES Warrior Run and Shady Point

AES's Warrior Run Generating Station is a 180 MW plant located in Cumberland, Maryland. Using a post-combustion CO_2 capture process, the plant captures approximately 45,000 tons CO_2/year to produce beverage grade CO_2, which is then sold to beverage manufacturers to generate revenues additional to those earned through power generation.[152]

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145 Michael Monea, *supra* note 141.
146 David Willberg, *SaskPower Pleased with CCS Performance in 2018*, ESTEVAN MERCURY (Jan. 23, 2019), https://www.estevanmercury.ca/news/business-energy/saskpower-pleased-with-ccs-performance-in-2018-1.23608225.
147 Int'l CCS Knowledge Ctr., *supra* note 112.
148 *See generally* 80 Fed. Reg. at 64,548-54.
149 *NRDC v. EPA*, 655 F.2d 318, 333 (D.C. Cir. 1981) ("the agency need only identify the major steps necessary for development of the device, and give plausible reasons for its belief that the industry will be able to solve those problems within the time remaining."); 80 Fed. Reg. at 64,557-58 (EPA detailed that pilot-scale data can demonstrate performance at full-scale by reviewing full-scale operations as well as the AEP Feed Study and Tenaska FEED study which document, in detail, how CCS can be implemented at full-scale. The NETL reports also contain hundreds of pages of detailed, documented explanation of how every aspect of full- and partial-scale CCS can be implemented at full-scale for both PC and IGCC facilities).
150 *Lignite Energy Council*, 198 F.3d at 934.
151 *Dist. Hosp. Partners*, 786 F.3d at 57 (the agency must examine the relevant data and show that the data is accurate and defensible).
152 AES Corp., *AES Sustainability Report* (2015), https://s2.q4cdn.com/825052743/files/doc_downloads/sustanaibility/2015/2015_AESSustainabilityReport.pdf.

AES Shady Point is a 360 MW coal-fired power plant located near Poteau, Oklahoma, that became the first coal-fired power plant to produce food-grade CO_2 using CCS on fossil fuels combustion.[153] Through captured CO_2, the facility produced 15,588 tons of dry ice and 61,287 tons of food-grade CO_2.[154]

In the 2015 rule, EPA relied, in part, on AES's two circulating fluidized bed coal-fired power plants utilizing carbon capture amine scrubbers developed by ABB/Lummus. These scrubbers have been capturing 5-10 percent of their CO_2 emissions from slipstreams since 2000 and 2001 demonstrating the "technical feasibility of post-combustion carbon capture."[155] The plants have been operating successfully for nearly twenty years at levels "reasonably similar to the level…that the EPA predicts would be needed …to meet the final standard of performance."[156] These plants were not developed in response to regulation or as government-funded demonstration projects. The current Proposal fails entirely to consider either of these carbon capture projects.

<u>Searles Valley Minerals</u>

EPA also relied, in part, on the Searles Valley Minerals soda ash plant in California which, since 1978, has been using post-combustion amine scrubbing to capture 270,000 tonnes CO_2/year from the flue gas of a coal plant.[157] That this plant provides electricity for on-site use is of no consequence because it serves the same purpose as the regulated sources – to provide electricity.[158] The plant was not developed in response to regulation or as a government-funded demonstration project but has provided significant learnings. Since 1978 the energy necessary to scrub CO_2 has been reduced about five times.[159] EPA concluded that "this project clearly demonstrates the technical feasibility of the amine scrubbing system for CO_2 capture from a coal-fired power plant."[160] The current Proposal fails entirely to consider this carbon capture project.

<u>AEP/Alston Mountaineer Project</u>

The 2015 record also includes the Mountaineer Project which retrofitted a 1,300 MW coal-fired plant with a 20 MW Alstom carbon capture slipstream.[161] The project commenced operation in 2009 and achieved capture rates from 75-90 percent. The project "reported robust steady state-operation during all modes of power plant operation, including load changes, and saw an availability of the CCS system of greater than 90 percent."[162] Captured CO_2 was stored on-site in two deep saline formations: 10,219 tonnes of CO_2 in the Rose Run sandstone at a depth of 2,362-2,392 meters, and

153 *Id.*
154 *Id.*
155 80 Fed. Reg. at 64,550.
156 *Id.*
157 *Id.* at 64,550-51.
158 *Id.* at 64,551.
159 *Id.* (citing Prof. Gary Rochelle, Plenary Address at GHGT-12, *From Lubbock, TX to Thompsons, TX--Amine Scrubbing for Commercial CO[2] Capture from Power Plants* (Oct. 2014)).
160 *Id.* at 64,550-51.
161 *Id.* at 64,552.
162 *Id.* (citing Alstom, Press Release, Alstom Announces Successful Results of Mountaineer Carbon Capture and Sequestration (CCS) Project (May 5, 2011)).

27,184 tonnes of CO_2 in the Copper Ridge dolomite at a depth of 2,482 to 2,545 meters.[163] In 2017, Battelle, an engineering-services provider hired by AEP, completed successful post-injection monitoring and site-closure operations at the Mountaineer Plant. Overall, the project demonstrated the full life-cycle of CCS, starting from site-characterization, carbon capture integration, injection, storage assessment, monitoring and site-closure with more than 200,000 hours of operations.[164] The project helped establish the technical viability of CCS to reduce greenhouse gas emissions from coal-fired power plants.

AEP intended to expand the project to capture 90 percent of the carbon from 235 MW of the plant but due, in part, to the "uncertain status of U.S. climate policy" the project was put on hold.[165] However, prior to the project being placed on hold, AEP prepared a Front End Engineering and Design (FEED) Report, explaining in detail how its pilot-scale work could be scaled up to successful full-scale operation, and to accommodate the operating needs of a full-scale power plant, including reliable generating capacity capable of cycling up and down to accommodate consumer demand. Recommended design changes to accomplish the desired scaling included detailed flue gas specifications, ranges for temperature, moisture, and SO_2 content; careful scrutiny of makeup water composition and temperature; quality and quantity of available steam to accommodate heat cycle based on unit load changes; and detailed scrutiny of material and energy balances.[166]

This report demonstrates how smaller-scale CCS projects can successfully be scaled up to full-scale operation.[167] EPA fails entirely to consider the Mountaineer Project or how the data from this, or other demonstration projects "may be used to predict performance in full scale plants."[168] Instead, EPA merely lists nearly seventy "notable pilot and demonstration CCS projects around the world" in the Review Memo accompanying the Proposal without considering whether these projects, along with the tens of operating, large-scale projects constitute a proper basis for determining that CCS is the best system of emission reduction.

Plant Barry

In 2012, Alabama Power's Plant Barry, in Bucks, Alabama demonstrated the availability of fully integrated CCS technology in the U.S.[169] The project captured and stored more than 114,000 tonnes

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163 Caitlin McNeil et al., *Lessons Learned from the Post-Injection Site Care Program at the American Electric Power Mountaineer Product Validation Facility*, 63 ENERGY PROCEDIA 6141 (2014) https://www.sciencedirect.com/science/article/pii/S1876610214024618.

164 Business Wire, *Battelle Completes 15-Year CO2 Storage Project at Mountaineer Power Plant* (October 26, 2017), https://www.businesswire.com/news/home/20171026006086/en/Battelle-Completes-15-Year-CO2-Storage-Project-Mountaineer.

165 80 Fed. Reg. at 64,552.

166 *Id.* (citing Matt Usher et al., AEP, *CCS Front End Engineering & Design Report, American Electric Power, Mountaineer CCS II Project* (2012), http://decarboni.se/sites/default/files/publications/32481/ccs-feed-report-gccsi-final.pdf).

167 *Id.* at 64,557.

168 *Sierra Club*, 657 F.2d at 341 n.157.

169 DOE, *DOE-Sponsored Project Begins Demonstrating CCUS Technology in Alabama*, ENERGY.GOV (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.adv-res.com/pdf/IJCCE20120200002_67424197.pdf.

of CO_2 before ending in December 2015.[170] 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.[171] CO_2 was captured at Plant Barry from a 25 MW emissions slipstream with post-combustion, MHI amine technology and transported 12 miles by pipeline to Denbury Resources' Citronelle oil field where the injection of CO_2 captured from Plant Barry began in August 2012 into the Paluxy sandstone, a saline brine-bearing formation.[172] 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 that can monitor in-zone pressure, temperature and CO_2 distribution.[173] Plant Barry is the first fully integrated CCS project on a coal-fired power plant to demonstrate non-endangerment of underground sources of drinking water (USDWs) and CO_2 containment to the injection zone using modeling and monitoring results, as required under EPA's UIC rules for the closure of an underground injection project.[174]

In 2015, EPA considered Plant Barry and the reports that the "plant performance was stable at the full load condition with CO_2 capture rate of 500 tpd at 90 percent CO_2 removal and lower steam consumption than conventional processes."[175]

The successful operational demonstration at Plant Barry was an important consideration in Petra Nova's decision to adopt the MHI technology for Petra Nova.[176] 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."[177] 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 tpd. In 2006, MHI applied the technology to a 10 MW slipstream at Japan's Matsushima 500 MW commercial coal-fired power plant. The long-term tests at this facility verified the impact of

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170 Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).
171 *Id.*
172 *Id.*
173 Glob. CCS Inst., *Global Status of CCS: 2013*, at 132 (2013), http://decarboni.se/sites/default/files/publications/115198/Global-Status-CCS-2013.pdf; Thomas M. Daley et al., Carbon Management Technology Conference, *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.
174 *See, e.g.,* Anne Oudinot et al., *Demonstration of Non-Endangerment at the SECARB Anthropogenic Test Site* (Oct. 2018) https://www.osti.gov/biblio/1473646; Rob Trautz, Anne Oudinot & David Riestenberg, *SECARB Anthropogenic Test Update* (Aug. 2014), https://www.osti.gov/biblio/1477178-secarb-anthropogenic-test-update (while Plant Barry operated under a state-issued Class V permit, the project adopted many of the requirements for Class VI wells).
175 80 Fed. Reg. at 64,552 (citing Michael A. Ivie et al., *Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama's Plant Barry*, 37 ENERGY PROCEDIA 6335 (2013), https://ac.els-cdn.com/S1876610213008060/1-s2.0-S1876610213008060-main.pdf?_tid=d18bd8f1-d47a-4766-aad8-612ad47ba161&acdnat=1552586657_2da637fe092f4696521ccadfd9e8aa85.).
176 Anthony Armpriester, *supra* note 58, at 6.
177 *Id.* at 11.

coal-fired flue gas impurities on the process and allowed MHI to develop solutions to these challenges.[178]

Plant Barry is now working towards the demonstration of yet another carbon capture technology, known as high-temperature carbonate fuel cell technology, through a partnership with ExxonMobil and FuelCell Energy.[179] While the project is still early in development, the FuelCell technology that would be implemented at Plant Barry is expected to "lower costs associated with current CCS processes by increasing the amount of electricity a power plant produces while simultaneously delivering significant reductions in carbon dioxide emissions."[180] SureSource 3000 fuel cell system by FuelCell Energy is expected to capture 54 tonnes of CO_2 every day from the natural gas-fired units at Plant Barry, while also generating 2.8 MW of electricity additional to the current plant output.[181] According to ExxonMobil a 500 MW power plant using a carbonate fuel cell could generate an additional 120 MW of power alongside capturing 90 percent of CO_2 emissions, while current CCS technology actually consumes power.[182] This would make CCS extremely cost-effective. At scale, ExxonMobil expects that Plant Barry's emissions profile to be more like a geothermal plant's and without the intermittency of wind and solar power.

The Proposal entirely fails to consider the Plant Barry project.

<u>Dakota Gasification</u>

The Dakota Gasification Great Plains Synfuel plant in North Dakota is a coal gasification facility that separates about 7,700 tpd of CO_2 for transportation by a pipeline crossing international borders, and injection for EOR and sequestration into the Weyburn Field and Midale field in Saskatchewan, Canada.[183] Over 35 Mt of CO_2 has been stored in these two fields since October 2000.[184] In addition to the purely commercial operation of this plant to produce synthetic natural gas and CO_2 for use in EOR, the project's sequestration operations were the subject of an 11-year, $85 million research project to predict and verify the containment of CO_2 and develop best practices for geologic CO_2 - the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project directed by the Petroleum Technology Research Centre.[185] Testing and evaluation of CO_2 sequestration monitoring methods

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178 *Id.* at 10.

179 ExxonMobil, *Advanced Carbon Fuel Cell Technology in Carbon Capture and Storage* (Sept. 18, 2018), https://corporate.exxonmobil.com/en/Research-and-innovation/Carbon-capture-and-storage/advanced-carbonate-fuel-cell-technology-in-carbon-capture-and-storage#exxonMobilAndFuelCellEnergyIncPartnership.

180 *Id.*

181 Matthew N. Eisler, *Fuel Cells Finally Find a Killer App: Carbon Capture*, IEEE SPECTRUM (May 29, 2018), https://spectrum.ieee.org/green-tech/fuel-cells/fuel-cells-finally-find-a-killer-app-carbon-capture.

182 *Id.*

183 Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019); MIT, *Weyburn-Midale Fact Sheet*, CARBON CAPTURE & SEQUESTRATION TECH. (Sept. 30, 2016), http://sequestration.mit.edu/tools/projects/weyburn.html; Petroleum Tech. Research Centre, *Weyburn-Midale*, http://ptrc.ca/projects/weyburn-midale (last visited Mar. 14, 2019).

184 *Id.*

185 Petroleum Tech. Research Ctr., *Weyburn-Midale*, http://ptrc.ca/projects/weyburn-midale (last visited Mar. 14, 2019); Univ. of N.D. Energy & Envtl. Research Ctr., *Weyburn–Midale CO_2 Project,* PLAINS CO2 REDUCTION P'SHIP, https://www.undeerc.org/PCOR/CO2SequestrationProjects/Weyburn.aspx. *See also*, Brian Hitchon, *Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the Weyburn-Midale CO_2 Storage Project* (2012), https://www.researchgate.net/publication/294687143_Best_practices_for_validating_CO2_geological_storage_Observations_and_guidance_from_the_IEA_GHG_Weyburn-Midale_CO2_Monitoring_Project.

include surface seismic, shallow groundwater, soil gas, and passive seismic techniques.[186] The project and associated monitoring efforts demonstrate the permanence of CO_2 sequestration in developed oil fields.[187]

In 2015 EPA demonstrated that the process used at Dakota Gasification "bears essential similarities to the…IGCC gasification systems," which could be utilized alone or in combination with pre-combustion CCS to meet the 1,400 lbs. CO_2/MWh standard of performance.[188]

> As with the IGCC gasification system, the Dakota Gasification facility gasifies coal (lignite) to produce a syngas which is then shifted to increase the concentration of CO[2] and to produce the desired ratio of CO and H[2]. As with the IGCC gasification system, the CO[2] is then removed in a pre-combustion capture system, and the syngas that results is made further use of. For present purposes, only the manner in which the syngas is used distinguishes the IGCC gasification system from the Dakota Gasification facility… Importantly, the CO[2] capture system that is used in the Dakota Gasification facility can readily be used in an IGCC EGU.[189]

The Proposal entirely fails to consider Dakota Gasification or complete a full survey of CCS technology utilized in other industries that is transferrable to the power sector.

<u>Coffeyville</u>

Coffeyville Resources, a subsidiary of CVR Energy, operates a nitrogen fertilizer plant in Coffeyville, Kansas.[190] Chaparral Energy, an independent oil and natural gas production and exploration company, worked with Coffeyville Resources to build a CO_2 compression facility at the plant site.[191] The project utilizes industrial separation to capture the CO_2.[192] The project commenced operation in 2013.[193] Approximately 650,000-770,000 tpa of CO_2 is captured through the fertilizer production process.[194] The plant converts petroleum petcoke to a hydrogen-rich syngas used to make chemicals and nitrogen fertilizer.[195] In the process, the CO_2, which is typically vented, is captured during the process of fertilizer production and is being transported 69 miles by pipeline to Chaparral's oil fields at its North Burbank Unit in Osage County, Oklahoma for EOR. As EPA concedes in the Review Memo associated with the Proposal, Chaparral was able to "make the economic case on each end of the pipeline."[196]

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[186] Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).
[187] *Id.*
[188] 80 Fed. Reg. at 64,553.
[189] *Id.*
[190] Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019); MIT, *Coffeyville Fact Sheet*, CARBON CAPTURE & SEQUESTRATION TECH. (Sept. 30, 2016), http://sequestration.mit.edu/tools/projects/coffeyville.html.
[191] *Id.*
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Id.*
[196] EPA, Memo: Review of the Current Status of Carbon Capture and Sequestration Projects, at 26-27, Doc. ID: EPA-HQ-OAR-2013-0495-11947 (Mar. 2018) (citing NETL & Great Plains Inst., DOE, *Siting and Regulating Carbon Capture, Utilization and Storage Infrastructure*, at 35-36 (Jan. 2017),

In 2015, EPA found that "the Coffeyville process involves gasification of a solid fossil fuel (petcoke), shifting the resulting syngas stream, and separation of the resulting CO[2] using a pre-combustion carbon capture system. These are the same, or very similar, processes that are used in an IGCC EGU."[197] While EPA describes the Coffeyville project in the Review Memo associated with the Proposal, it fails to explain why it does not show that carbon capture technology is adequately demonstrated and available.

iv. New CCS projects in the pipeline

There are currently twelve CCS projects under construction around the world and tens more in development phases.[198]

One of the most relevant projects to this rulemaking is Minnkota Power's Project Tundra. This project is currently in the research and development (R&D) phase for a post-combustion carbon capture project at Unit 2 of Young Station - an existing 455 MW lignite coal-fired power plant, located near Center, North Dakota.[199] Minnkota recently explained that "[t]he technology needed for this project is already commercially available."[200]

The developers plan to use amine solvents like those used at Petra Nova but also scale-up the facility such that it captures almost double the volume of CO_2 than Petra Nova. At a 90 percent capture rate, approximately 2.3-3.6 Mt of CO_2 could be captured and stored annually – however, the developers are eyeing any even-higher 95 percent capture rate. The project also aims to achieve technical and operational efficiencies by expanding on Petra Nova's experience and to demonstrate commercial availability of CCS technologies for lignite or other low-rank coals. The project plans to pipe the captured CO_2 approximately 100 miles away for use in EOR operations. The project developers cite the need to comply with federal and other regulations as the reason for retrofitting the plant with carbon capture. But President and CEO of the Lignite Energy Council, Jason Bohrer, notes that "[r]educing emissions won't happen without projects like this. The United States has to lead the way and provide a model for other countries as they seek to reduce their carbon emissions."[201]

EPA provides a list of twenty large-scale CCS projects that are in early development, advanced development, or in construction in its Review Memo but fails entirely to explain why these projects, along with the twenty in operation – which are *not* listed - are insufficient to show that CCS is adequately demonstrated and available at reasonable cost.

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https://www.energy.gov/sites/prod/files/2017/01/f34/Workshop%20Report--Siting%20and%20Regulating%20Carbon%20Capture%2C%20Utilization%20and%20Storage%20Infrastructure.pdf.

197 80 Fed. Reg. at 64,554.

198 Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).

199 *See* Minnkota Power Coop., *Minnkota Power Cooperative Proposal Entitled "Project Tundra FEED"* (Nov. 1, 2018), https://www.nd.gov/ndic/lrc/meeting1811/II-c-proposal.pdf; Project Tundra, https://www.projecttundrand.com/ (last visited Mar. 14, 2019).

200 Bonnie Meibers, *2019 a "Critical" Year for Project Tundra,* GRAND FORKS HERALD (Jan. 12, 2019), https://www.grandforksherald.com/business/energy-and-mining/4555639-2019-critical-year-project-tundra.

201 *Id.*

v. International CCS projects

Standards may properly be based on the performance of foreign projects.[202] In 2015, EPA reviewed "international projects that are in various stages of development that indicate confidence by developers in the technical feasibility of pre-combustion capture."[203] Two of the large-scale projects EPA reviewed in 2015 have since come online.

Emirates Steel

Abu Dhabi National Oil Company (ADNOC) and Masdar Clean Energy, in 2016, launched Al Reyadah CCS project to capture 0.8 Mt of CO_2 from Emirates Steel plant in Mussafah district. The captured CO_2 is piped to Rumaitha and Bab oil fields, owned by ADNOC, for EOR.[204] In November 2018, ADNOC announced the expansion of capture projects to other gas processing plants and capture 5 Mt of CO_2 by 2030.[205]

Uthmaniyah

In 2015, Saudi Aramco started operating CCS at the Hawiyah NGL natural gas processing plant, which has the capability to capture 0.8 Mtpa of CO_2.[206] The plant pipes the CO_2 for utilization in EOR operations at Uthmaniyah oil field, 85 km away.[207]

Again, EPA merely lists dozens of international projects without providing any reasoned analysis as to why these projects, along with the rest of the 2015 record, do not provide adequate support for the determination that CCS is the best system of emission reduction.

vi. Canceled projects

Several coal gasification projects with CCS were canceled around the time of EPA's initial 2015 rulemaking. These projects, Kemper, TCEP, and HECA are described in varying detail in EPA's Review Memo released as part of the Docket.

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[202] *See Sierra Club*, 657 F.2d at 364 (achievability of standard upheld, even though no domestic source was achieving the promulgated limit, due in part to successful operation of the technology in Japan); *see also Lignite Energy Council*, 198 F.3d at 394 n. 3 (section 111 (b) standard of performance justified in part based on data from "foreign boilers burning lignite").
[203] 80 Fed. Reg. at 64,553.
[204] Iman Ustadi et al., *The Effect of the Carbon Capture and Storage (CCS) Technology Deployment on the Natural Gas Market in the United Arab Emirates*, 114 ENERGY PROCEDIA 6366 (2017), https://www.sciencedirect.com/science/article/pii/S1876610217319756.
[205] Sam Bridge, *UAE's ADNOC Says Moving Ahead with CO_2 Capture Project*, ARABIAN BUSINESS (Nov. 29, 2018), https://www.arabianbusiness.com/energy/408982-uaes-adnoc-says-moving-ahead-with-co2-capture-project.
[206] Glob. CCS Inst., *Facilities Database*, CO2RE, https://co2re.co/FacilityData (last visited Mar. 14, 2019).
[207] Zero Emission Resource Org., *Uthmaniya CO2-EOR Demonstration Project*, http://www.zeroco2.no/projects/uthmaniyah-co2-eor-demonstration-project (last visited Mar. 14, 2019).

All of these projects relied on either Selexol™ or Rectisol™ [208] carbon capture technologies that have been commercially available since the 1950s and 1960s.[209] The cancellation of these projects was unrelated to CCS. [210] Instead, market conditions such as rising capital costs and falling natural gas prices made these projects uneconomic. In the case of Kemper, the challenges were increased by using a new, first commercial application of the TRIG gasifier. The scale-up of this technology from pilot scale to 582 MW – a nearly 100-fold increase in scale-caused additional cost overruns.[211] Moreover, in 2015, EPA found that "Kemper cost overruns reflected highly questionable strategic decisions (virtually build first, design later) that are not generally applicable."[212]

EPA's Review Memo, a collection of information "obtained via internet searches" without any analysis or conclusions, and focusing primarily on canceled projects, does not represent the type of investigation required of an expert agency. Rather than regurgitating "excerpts from articles," it is incumbent upon the Agency to review and analyze primary sources and reach out to companies, vendors and other experts to then develop its own informed conclusions upon which to base regulation. Regardless, the clips the Agency hand picks to vaguely support its predetermined conclusion are out of context, incomplete and in some cases erroneous.

Instead of looking forward and forcing technological advancement, EPA cherry-picks and focuses on idiosyncrasies of historic projects that, for reasons particular to those projects, and not to the technical feasibility of CCS, were canceled. This dim view of CCS's potential is antithetical to the purpose of the Clean Air Act and section 111. As we explain throughout these comments, CCS is adequately demonstrated at reasonable costs, and each project is building upon previous learnings and achieving performance improvements and cost declines.

2. Vendor guarantees

Since the first section 111 cases were heard before the D.C. Circuit in 1973, the court has continually affirmed that performance guarantees from vendors are an important basis for finding that a system of emission reduction is adequately demonstrated.[213] Therefore, in 2015, EPA undertook to review

[208] MIT, *Texas Clean Energy Project (TCEP) Fact Sheet: Carbon Dioxide Capture and Storage Project*, CARBON CAPTURE & SEQUESTRATION TECH. (Sept. 30, 2016), https://sequestration.mit.edu/tools/projects/tcep.html; DOE, *Hydrogen Energy California Project* https://www.energy.gov/fe/hydrogen-energy-california-project (last visited Mar. 15, 2019); Matt Nelson et al., *Carbon Capture at the Kemper IGCC Power Plant* (Oct. 2018), https://az659834.vo.msecnd.net/eventsairwesteuprod/production-ieaghg-public/6eb828a1c1a6412eb982bce89d6482b2.
[209] *Rectisol Process*, Science Direct (2017), https://www.sciencedirect.com/topics/engineering/rectisol-process (Selexol since 1960s, Rectisol since 1955).
[210] John Thompson, *Two Carbon Capture Projects: A Deeper Look*, CATF (July 19, 2017), https://www.catf.us/2017/07/two-carbon-capture-projects/.
[211] Peter Maloney, *After Kemper, New 'Clean Coal' Plants Face Long Odds*, UTILITYDIVE (July 5, 2017), https://www.utilitydive.com/news/after-kemper-new-clean-coal-plants-face-long-odds/446288/.
[212] EPA, Response to Comments, Cost and Benefits, at 3-90, Doc. ID: EPA-HQ-OAR-2013-0495-11862 (Oct. 23, 2015).
[213] *Essex Chem. Corp.*, 486 F.2d at 440 (upholding standards based, in part on, "documentation of manufacturer guarantees and expectations"); *Sierra Club*, 657 F.2d at 364 (noting in upholding standards "we find it informative that the vendors of FGD equipment corroborate the achievability of the standard"); *Portland Cement Ass'n*, 486 F.2d at 401-02 ("It would have been entirely appropriate if the Administrator had justified the standards . . . on testimony from experts and vendors made part of the record."); *Nat'l Petrochem & Refiners*, 287 F.3d at 1137 (noting that vendor guarantees are an indicia of availability and achievability of a technology-based standard since, notwithstanding a desire to promote

the literature and performance guarantees available from all carbon capture vendors and found that Linde and BASF, Fluor, Mitsubishi Heavy Industries, and Shell offer carbon capture technology and "have publicly expressed confidence in the technical feasibility of carbon capture," calling it "proven and cost-effective."[214]

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 capture CO_2 from power plants is through post-combustion capture using amine-based solvents. The main licensors – Shell (Cansolv Process), MHI (KM CDR Process), Fluor (Ecoamine FG+), Kerr-McGee/ABB Lummus, Siemens (Post-CAP), Dow (DOW Amines) – have had reference plants in operation for many decades and have been investing in their solvents in order to compete on the scale required for large-scale CCS projects.[215] In 2018, the United Kingdom Department for Business, Energy and Strategy commissioned a literature review, which described various capture technologies, vendors, studies, and projects.[216] The review demonstrates that carbon capture is available, adequately demonstrated, that costs are coming down and that the current standard is achievable. We briefly describe the offerings from some of the main vendors below, but it is incumbent upon EPA to engage with these companies and obtain publicly available information as well as information under the seal of confidentiality to properly assess carbon capture technology.

Fluor has said "[t]he Econamine FG+ technology is ready for full-scale deployment in: Gas- and Coal-fired Power plants,"[217] and commercial activity supports their assertion.[218] 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, 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."[219] Fluor partnered with Uniper to jointly build a demonstration CO_2 capture plant based on Fluor's Econamine FG Plus[SM] technology at Uniper's hard coal power plant in Wilhelmshaven, Germany. Completed in late 2015, the three-year test project "incorporates several recent technology enhancements that can be directly applied to a full sized plant," and "generated useful data related to energy consumption,

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sales, "a manufacturer would risk a considerable loss of reputation if its technology could not fulfill a mandate that it had persuaded EPA to adopt").

214 80 Fed. Reg. at 64,554-55; *see also* EPA, Technical Support Document: Literature Survey of Carbon Capture Technology, at 9-11, Doc. ID: EPA-HQ-OAR-2013-0495-11773 (July 10, 2015).

215 Amec Foster Wheeler Grp. Ltd., *Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology*, at 5-6 (2018), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/730560/Literature_Review_Report_Rev_2A__1_.pdf.

216 *Id.* at 5-6.

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

218 Amec Foster Wheeler Grp. Ltd., *supra* note 215, at 37-38.

219 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.

emissions profiles, and other information to facilitate the scale-up of the process to a full-sized coal based power plant."[220]

Shell Canslov offers its post-combustion capture system for a variety of industries, including coal-fired and natural gas-fired plants.[221] 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.[222] The Lanxess plant captures CO_2 from the flue gas created by burning natural gas in conventional boilers.[223] Also, Cansolv Technologies in partnership with RWE power piloted their process at the Aberthaw Power Station in South Wales.[224]

In August 2016, Linde Group and BASF completed a pilot-scale demonstration of a novel aqueous amine-based process, OASE blue, at the National Carbon Capture Center (NCCC) in Wilsonville, Alabama.[225] The pilot was conducted on a coal-fired power plant flue gas at the scale of 1- 1.5 MWe for 1,500 continuous hours. The new Linde-BASF technology aimed at lowering overall energy consumption and capital costs by using OASE blue, which reduces regeneration energy requirements and is very stable under the coal-fired power plant feed gas conditions. The developers report[226] that the pilot demonstrated CO_2 capture rate exceeding 90 percent and CO_2 purity exceeding 99.9 mol percent (dry.) According to the final test report, the cost of capture is estimated to be roughly 30 percent lower than DOE's reference case for a 550 MW supercritical pulverized coal plant with Fluor's Ecoamine CDR carbon capture technology. Dr. Christian Bruch, Member of the Executive Board of the German corporation, signified, "[t]he result should prove that CO_2 capture is economically feasible, substantially reducing emissions and their negative impact on climate."[227] In 2018, Linde received grants from DOE to scale their technology to 10 MW scale.[228]

Siemens has piloted its PostCap™ post-combustion CO_2 capture process at the E.ON-owned Staudinger coal-fired power plant near Frankfurt, Germany, which began in 2009 and operated for more than 9,000 hours. Siemens concluded that "[t]he results of the pilot plant operation will serve as basis for the implementation of a demonstration plant, which will be the final step before a full-

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220 Satish Reddy et al., *Fluor's Econamine FG PlusSM Completes Test Program at Uniper's Wilhelmshaven Coal Power Plant*, 114 ENERGY PROCEDIA 5816 (2017), https://ac.els-cdn.com/S1876610217319203/1-s2.0-S1876610217319203-main.pdf?_tid=581cfaad-d3d0-4b77-8683-e96e49ebef9f&acdnat=1552593414_a6013f33e7779e23b082fae424258001.

221 Shell Glob. Sols. Int'l 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 (last visited Mar. 14, 2019).

222 Cansolv Techs. Inc., *Shell Cansolv CO2 Capture Underway in Unique Application*, SHELL (Oct. 10, 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.

223 *Id.*

224 Shell, *New Life for Coal-Fired Power*, https://www.shell.com/business-customers/global-solutions/impact-magazine/new-life-for-coal-fired-power.html (last visited Mar. 14, 2019).

225 Amec Foster Wheeler Grp. Ltd., *supra* note 215, at 12-13.

226 Devin Bostick, *Final Testing Report to NCCC* (Jan. 27, 2017), https://static1.squarespace.com/static/566b0ac3df40f3a731712cf4/t/58f53329bebafb77565eda81/1492464428545/Linde-BASF+-+Slipstream+Pilot-Scale+Demonstration+of+a+Novel+Amine-Based+Post-Combustion+Technology+for+Carbon+Dioxide+Capture+from+Coal-Fired+Power+Plant+Flue+Gas.pdf.

227 Rhea Healy, *Linde and BASF Complete Successful CO2 Capture Pilot Project at NECC in Alabama*, GAS WORLD (Jul. 20, 2016), https://www.gasworld.com/co2-capture-pilot-project-from-linde-and-basf-a-success/2010739.article.

228 *Linde Secures Grants from U.S. DOE for Carbon Capture Projects*, POWER TECH. (May 16, 2018), https://www.power-technology.com/news/linde-secures-grants-us-doe-carbon-capture-projects/.

scale commercial carbon capture plant project."[229] Siemens was chosen to provide its post-combustion capture technology for the 565 MW Meri-Pori IGCC coal plant in Finland to capture 50 percent of the flue gas at a 90 percent+ capture rate. Although the project ultimately was not built, Siemens noted that "the one-and-a-half-year technology qualification program comprised solvent stress tests, a pilot plant operation and a comprehensive engineering of the large-scale CO_2 capture plant."[230]

Thirteen commercial plants in operation and one under construction use MHI's KM CDR Process®, including Petra Nova, which demonstrates that full-scale utility CO_2 capture is now available with this technology.[231] 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 gas-fired power plants.[232] Since the successful Petra Nova project, the MHI team has increased its capture capability process to 90 percent. The process, known as the "Advanced KM CDR Process" now features a new solvent (KS-21) which offers a higher technical advantage compared to KS-1, including higher stability and lower volatility.[233]

Carbon Clean Solutions has a globally available commercial offering of innovative solvent technology that offers economic and performance benefits relative to conventional solvents used for CO_2 capture.[234] Their product APBS CDRMax™ offers 40 percent lower OPEX and 30 percent lower CAPEX compared to conventional solvent technologies. The CDRMax™ capture process uses proprietary solvents, process equipment, and heat integrated processes to deliver energy and economic efficiencies: 20 percent drop in thermal energy needed, 20 times less corrosion and 10 times less degradation of solvent due to less foaming that leads to higher performance. As a co-benefit, there is a reduction in aerosol emissions as well.

Despite the fact that vendor guarantees alone could serve as the basis of a determination that CCS is adequately demonstrated, the Proposal entirely fails to review the current vendor offerings, guarantees, and statements.

3. Literature review

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[229] Tobias Jockenhövel & Rüdiger Schneider, *Towards Commercial Application of a Second-Generation Post-Combustion Capture Technology: Pilot Plant Validation of the Siemens Capture Process and Implementation of a First Demonstration Case*, 4 ENERGY PROCEDIA 1451 (2011), https://www.researchgate.net/publication/251711840_Towards_Commercial_Application_of_a_Second-Generation_Post-Combustion_Capture_Technology_-_Pilot_Plant_Validation_of_the_Siemens_Capture_Process_and_Implementation_of_a_First_Demonstration_Case.

[230] Siemans AG, *Frequently Asked Questions (FAQ): Carbon Capture Utilization and Storage* (2014), https://www.energy.siemens.com/mx/pool/hq/power-generation/power-plants/carbon-capture-solutions/FAQ-summary%202014_07_24-revOR.pdf.

[231] MHI, *Update on Mitsubishi's KM CDR Process™ and Experience* (2018), https://www.cslforum.org/cslf/sites/default/files/documents/Venice2018/Mitsubishi_Capture_Process_Update.pdf; Amec Foster Wheeler Grp. Ltd., *supra* note 215, at 6-8.

[232] MHI, *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.

[233] Sonal Patel, *supra* note 101.

[234] Carbon Clean Solutions, *APBS CDRMax: CO2 Capture/Recovery*, https://carboncleansolutions.com/technology/co2-capture-solvents/profile/apbs-cdrmax (last visited Mar. 14, 2019); *see also* Amec Foster Wheeler Grp. Ltd., *supra* note 215, at 10-11.

The Courts have found that section 111 standards can be justified by "testimony from experts,"[235] and "literature sources."[236] In 2015, EPA noted that there was a large body of academic literature on the technical feasibility and demonstration of CCS[237] EPA prepared a Technical Support Document compiling relevant literature.[238] The Document reviewed literature covering existing projects that implement CCS, existing projects that implement various components of CCS, planned CCS projects, and scientific and engineering studies of CCS. EPA determined that CCS is adequately demonstrated based on the fact that post-combustion CCS is demonstrated in full-scale operation within the electricity generating industry, and full-scale, pre-combustion CCS has been demonstrated in several chemical industry plants with results that are transferable to the electricity sector.

The relevant literature to this rulemaking supports the current standard and continues to accumulate. In Appendix A, we summarize the results of our preliminary literature review. The recently available literature builds upon the 2015 record demonstrating that the U.S. is well positioned to support CCS projects, the technology is adequately demonstrated, costs are declining, and CCS is an important piece of transitioning to decarbonized economy and meeting climate goals.

EPA fails to engage with the extensive literature review it performed in 2015 and fails to update the review. The current literature continues to demonstrate that CCS is the best system for this source category and EPA has not provided any documentation supporting its reversal.

B. Sequestration is adequately demonstrated and available.

In 2015, EPA, based on overwhelming evidence, determined that geologic sequestration of CO_2 is technically, economically and geographically available and adequately demonstrated for the purpose of reducing carbon emissions from fossil fuel-fired power plants.[239] EPA described evidence from the U.S and across the globe demonstrating that CO_2 can be injected and sequestered safely both in depleted oil fields and saline aquifers. And as we describe below, the technical record has become even more robust since 2015.

EPA proposes to discount the robust and expanding record demonstrating the availability of geologic sequestration because analysis has not been undertaken to determine the "areas where projects make business and financial sense."[240] This is not the standard under section 111. "It is the system which must be adequately demonstrated and the standard which must be achievable. This does not require that a … plant be currently in operation which can at all times and under all circumstances meet the standards"[241] There is a robust record, discussed below, that supports EPA's 2015 finding that geologic sequestration is adequately demonstrated. And further, there are a variety of means to access storage or achieve the standard through other measures. The Act certainly does not require that economic and technical analysis be performed for *every* basin and potential project in

[235] *Portland Cement*, 486 F.2d at 401-02.
[236] *Essex Chem. Corp.*, 486 F.2d at 440.
[237] 80 Fed. Reg. at 64,555.
[238] EPA, Technical Support Document: Literature Survey of Carbon Capture Technology, Doc. ID: EPA-HQ-OAR-2013-0495-11773 (July 10, 2015).
[239] 80 Fed. Reg. at 64,575-81; EPA, Technical Support Document: Geographic Availability, Doc. ID: EPA-HQ-OAR-2013-0495-11772 (July 31, 2015).
[240] 83 Fed. Reg. at 65,442.
[241] *Essex Chem. Corp.*, 486 F.2d at 433.

order to demonstrate that geologic sequestration is available for the source category. Such a standard is not only unworkable, but it is contrary to the Clean Air Act's statutory mandates.

CO_2 and hydrocarbons have been trapped for millions to hundreds of millions of years. Moreover, deep geologic injection and storage technology has been used for decades in the National Petroleum Reserve, safely containing 2.5 trillion cubic feet of injected gas.[242] Furthermore, billions of tons of liquid waste are disposed of in saline aquifers annually, *see infra*. Subsurface CO_2 management know-how is proven by one billion tons of new CO_2 injected (and much more reinjected) accompanied by five decades' worth of management experience in depleted oil fields. Add to that the millions of tons of saline storage test injections and attendant CO_2 monitoring.

The National Carbon Storage Atlas, version V, the previous of which was relied upon by EPA in its 2015 rule, is underpinned by hundreds of publications representing several decades of regional geologic storage research.[243] And as described below, there are voluminous subsurface data resources and important databases that confirm that geologic sequestration is "reasonably reliable, reasonably efficient, and …can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[244]

Despite the undocumented statements to the contrary in the Proposal, sequestration resources are widely available in the U.S. and new plants have the opportunity to site near them or utilize pipelines and/or transmission lines to access sequestration and accommodate demand. Moreover, there are many areas of the country where new plants will not be built either due to state or utility regulations and policies or lack of demand. New plants also have the option of co-firing with natural gas or building an IGCC to meet the standard.

1. EPA's standard for availability is illegal and unworkable.

The Proposal attempts to undermine EPA's 2015 record of available, secure storage without offering any new information or different conclusions but by instead advancing an illegal new test for availability. The Proposal discounts the NETL Carbon Storage Atlas and its assessment of geologic storage because it does not set forth the economics for each individual storage area—essentially requiring a business case to be made for each basin. The Proposal simply asserts this new requirement with no attendant data and provides no evidence that the storage capacities identified in the 2015 rule are not viable. This fails to satisfy the requirement that "good reasons"[245] are provided for a change in agency position.

The Proposal asserts that "deployment of partial-CCS is site-specific and its application will depend on local market and geologic conditions,"[246] adding that "[w]hile storage capacity appears large in the Atlas, site-specific technical, regulatory and economic considerations will ultimately impact how

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[242] EIA, *Weekly Natural Gas Storage Report*, http://ir.eia.gov/ngs/ngs.html (last visited Mar. 14, 2019). Citing 2,500 billion ton 5-year average for underground natural gas storage.
[243] NETL, *NATCARB*, NETL'S ENERGY DATA EXCHANGE, https://edx.netl.doe.gov/group/natcarb (last visited Mar. 14, 2019).
[244] *Essex Chem. Corp.*, 486 F.2d at 433; 83 Fed. Reg. at 65,433 (quoting same).
[245] *Fox Television Stations.*, 556 U.S. at 515.
[246] 80 Fed. Reg. at 65,441.

much of that resource is economically available."[247] This is as true for CCS as it is for any new power or industrial project.

The Clean Air Act does not require EPA to put forth the business case for building a new power plant on every square foot of the country before finalizing uniform, nationally applicable pollution standards. Such a test would be so burdensome that no regulations would ever be finalized, rendering the Act entirely powerless. Section 111 allows EPA to set standards based on "reasonable extrapolation" that can be made based on the technology's performance in other contexts. Further, the technology need not even "be in actual routine use somewhere,"[248] so long as it is available to new plants. All evidence points to extensive and widespread availability of geologic sequestration.

In 2015, EPA understood that "other considerations such as pore space availability and ownership, economics, and legal constraints will factor into which fields are developed within each geographic basin."[249] However, the Agency "carefully reviewed the assumptions on which the transport and storage cost estimates are based and continue[d] to find them reasonable."[250]

After a new plant has completed its business planning and feasibility studies, EPA has in place a significant permitting and oversight process that considers the individual projects and storage sites on a case-by-case basis. It is during this permitting process that a company and EPA will determine whether a storage site and the company's injection program is sufficient to maintain environmental standards.

EPA's regulatory construct for sequestration was finalized nearly a decade ago in two 2010 rules. The two key federal rules govern CO_2 injected for geologic storage: 1) the Safe Drinking Water Act's UIC, permit classes II (oil and gas) and VI (geologic sequestration) administered by the EPA Water Quality Division, and, 2) the Clean Air Act's GHGRP subpart RR administered by the EPA's Air Pollution Division.[251] Geologic sequestration that takes place during CO_2-EOR is regulated under UIC Class II, containing requirements to protect USDWs from underground-injection-related contamination. Projects that are designed to only sequester CO_2 are regulated under comprehensive UIC Class VI regulations to protect USDWs which include such tasks as demonstrating the appropriateness of a site for sequestration, well construction and operational requirements including monitoring the fate of injected CO_2, and well closure and post-project monitoring. The GHGRP's Subpart RR imposes complementary requirements for monitoring of injected CO_2, reporting and accounting of volumes of CO_2 leaked and sequestered. Together, EPA's water and air rules ensure that CO_2 is safely injected, sequestered and accounted for.

Importantly, some states, such as Texas (onshore and offshore), North Dakota, Wyoming, Montana, Oklahoma, Kansas, Louisiana, West Virginia have recognized the commercial availability of carbon

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[247] *Id.* at 65,441-42.
[248] *Portland Cement*, 486 F.2d at 391 (quoting S. Rep. No. 91-1196, at 16 (1970)); 83 Fed. Reg. at 65,433 (quoting same).
[249] EPA, Technical Support Document: Geographic Availability, at 9, EPA-HQ-OAR-2013-0495-11772 (July 31, 2015).
[250] EPA, Response to Comments, Cost and Benefits, at 3-106, EPA-HQ-OAR-2013-0495-11862 (Oct. 23, 2015).
[251] EPA, *Protecting Underground Sources of Drinking Water from Underground Injection*, https://www.epa.gov/uic (last visited Mar. 14, 2019); EPA, *Greenhouse Gas Reporting Program (GHGRP) – Subpart RR – Geologic Sequestration of Carbon Dioxide*, https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide (last visited Mar. 14, 2019).

storage, enacting their own legislation and regulations that cover such areas as liability, pore space ownership, CO_2 ownership, unitization, mineral rights interstate issues.[252]

The table below illustrates that EPA had issued six Class VI permits to prospective CCS projects, and another application permit was pending when the current rule was finalized. EPA explained that "these permits demonstrate that these projects are capable of safely and securely sequestering large volumes of CO_2 – including from steam generating units – for long-term storage since the EPA would not otherwise have issued the permits."[253] Moreover, the table shows that, since the current rule was finalized, the EPA Air Quality Division's GHGRP has approved five monitoring verification and accounting plans for sequestration projects.

Table 1: Approved Class VI Permits and Monitoring Verification Plans

	Approved UIC Class VI Permits				
	Project	**Approval**	**Date**	**Status**	**Ref**
1	FutureGen Alliance, Jacksonville IL	EPA Region V Water Div	29-Aug-14	DOE Closeout during permit review delay	https://archive.epa.gov/region5/water/uic/futuregen/web/html/index.html
2	FutureGen Alliance, Jacksonville IL	EPA Region V Water Div	29-Aug-14	DOE Closeout during permit review delay	https://archive.epa.gov/region5/water/uic/futuregen/web/html/index.html
3	FutureGen Alliance, Jacksonville IL	EPA Region V Water Div	29-Aug-14	DOE Closeout during permit review delay	https://archive.epa.gov/region5/water/uic/futuregen/web/html/index.html
4	FutureGen Alliance, Jacksonville IL	EPA Region V Water Div	29-Aug-14	DOE Closeout during permit review delay	https://archive.epa.gov/region5/water/uic/futuregen/web/html/index.html
5	ADM - IBDP large scale 1 Mt Demonsration	EPA Region V Water Div	28-Dec-14	Injection complete.. 10 yr PISC phase	http://www.sseb.org/wp-content/uploads/2010/05/Greenberg.pdf
6	ICCS- Industrial Scale CCS 5 Mt Project	EPA Region V Water Div	1-Feb-15	Injection began 7 April 2017.	http://www.sseb.org/wp-content/uploads/2010/05/Greenberg.pdf
7	Wellington Kansas Geological Survey	EPA Region VII Water Div	1-Dec-14	1468 p. application submitted May 2014, permit never granted, effort supended March 2018. Injection Project completed	http://www.kgs.ku.edu/PRS/ICKan/2018/Aug/Wreath_A_Kansas_Independent_Perspective_on_CO2_Flooding.pdf
	Approved GHGRP Subpart RR MRV Plans	**Approval**	**Date**	**Status**	**URL for MRV Plan and Decision**
1	Occidental Denver Unit	EPA GHG Reporting Branch	22-Dec-15	Operational	https://www.epa.gov/ghgreporting/denver-unit
2	Occidental Hobbs Field	EPA GHG Reporting Branch	12-Jan-16	Operational	https://www.epa.gov/ghgreporting/hobbs-field
3	ADM ICCS Industrial Scale Project	EPA GHG Reporting Branch	12-Jan-16	Operational	https://www.epa.gov/ghgreporting/archer-daniels-midland-company-illinois-industrial-carbon-capture-and-sequestration
4	Exxon Shute Creek	EPA GHG Reporting Branch	20-Jun-18	Operational	https://www.epa.gov/ghgreporting/shute-creek-facility
5	Core Energy Northern Niagran Pinnacle Reef Trend	EPA GHG Reporting Branch	12-Oct-18	Operational	https://www.epa.gov/ghgreporting/core-energy-northern-niagaran-pinnacle-reef-trend

New source performance standards are uniform, nationally applicable standards, and EPA need not perform a case-by-case economic analysis for every storage site in the country to demonstrate its availability. As these permits demonstrate, individual projects are able to access and utilize storage basins in an environmentally protective and economically feasible manner.

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252 Holly Javedan, MIT, *Regulation for Underground Storage of CO_2 Passed by U.S. States* (2011), https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf; IEA, *Carbon Capture and Storage Database*, https://www.iea.org/ccsdatabase/ccs/ (last visited Mar. 14, 2019).

253 80 Fed. Reg. at 64,585.

2. **Geologic sequestration is technically feasible and available throughout most of the United States.**

In 2015, EPA found that "[s]ubsurface formations suitable for GS of CO_2 captured from affected EGUs are geographically widespread throughout most parts of the United States."[254] EPA concluded that there are 39 states with identified onshore and offshore deep saline storage capacity and that there are 29 states where EOR operations are either undergoing or possible.[255]

New plants have the option to site in economically advantageous locations amenable to CCS. To that end, most CCS projects have chosen to locate in areas with offtake access to EOR operations, which can provide revenue from the sale of CO_2. Plant owners that do not build directly on top of CO_2 storage resources may be able to tap into the growing CO_2 pipeline network or build their own pipeline to long-distance trunklines. Pipelines over 300 miles long have been found to be economic and built in order to access EOR offtake. Plant owners also have the option of building closer to storage offtake and tapping into the vast transmission network in order to sell electricity to customers hundreds of miles away.

Despite the fact that the combination of widespread sequestration opportunities, pipelines and transmission lines makes it possible to build a new CCS project virtually anywhere in the country, EPA specifically recognized in 2015 that there is no right to build a coal plant on any square foot of the country.[256] As described further below, at Part III.E., to be "achievable" a standard "must be capable of being met under most adverse conditions which can *reasonably be expected to recur*…"[257] Therefore, EPA need not design a standard for every possibility, only those which can reasonably be expected to occur. 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.[258] Congress determined that "[m]ajor new facilities such as electric generating plants…must be controlled to the maximum practicable degree regardless of location."[259]

There are many locations where a new plant is not reasonably expected, regardless of conditions, and EPA need not design a standard that accommodates those places.[260] For example, depending on state laws, regional carbon reduction strategies, utility carbon reduction initiatives, attainment designations for criteria pollutants and demand for electricity, there are broad swaths of the country where a coal plant will not or cannot be built.

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254 *Id.* at 64,575.
255 *Id.* at 64,576.
256 *Id.* at 64,540 (referencing 79 Fed. Reg. 1,430, at 1,466); *see also* EPA, Response to Comments, Legal Issues, at 2-3, Doc. ID: EPA-HQ-OAR-2013-0495-11861 (Oct. 23, 2015) ("EPA disagrees with the commenter that section 111 must allow a new plant to be sited anywhere (particularly given the choice of a new plant as to where to locate) . . . ").
257 *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980) (emphasis added).
258 *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).
259 S. Rep. 91-1116 at 16 (1970). *See* 116 Cong. Rec. 42,384 (statement of Sen. Muskie) (summarizing the House-Senate Conference agreement).
260 *Portland Cement*, 665 F.3d at 191 (holding that the EPA could adopt section 111 standards of performance based on the performance of a kiln type that kilns of older design would have great difficulty satisfying, since, among other things, there were alternative methods of compliance available should a new kiln of this older design be built. The court also noted that it was highly unlikely that such a new kiln would ever be constructed, and that the EPA could consider this in adopting a standard of performance reflecting a different type of kiln design).

Nonetheless, between pipelines and transmission lines, CCS plants can be built anywhere in the country with demand and a regulatory structure conducive to new coal-fired power plants. New plant owners also always have the option of co-firing with natural gas to meet the standard, as described in Part IV. EPA has failed to consider these "significant and viable alternatives," never mind "give a reasoned explanation for its rejection of such alternatives," rendering the Proposal arbitrary and capricious.[261] Tellingly, after a four-month comment period and over 11,000 comments in 2015, *no* commenter provided evidence of a proposed plant, or plan, or location that could not accommodate a plant meeting the current standard.[262]

a. The Proposal underestimates geologic sequestration opportunities.

While the Proposal concedes that the geographic extent of potential geologic storage has expanded[263] since 2015, it implies that there is inadequate subsurface data to prove up the availability of geologic sequestration resources in U.S. geologic reservoirs. The NATCARB database and maps revised in 2015 are a very useful national resource, however, there are several very significant storage data studies and accompanying resources, described below, that EPA has not cited in the Proposal, which also demonstrate the availability of pore space and large-scale sequestration resources.

i. The National Carbon Sequestration (NATCARB) Atlas and database are underpinned by two decades of research and demonstration.

In its Proposal, EPA, with a broad brush, and lacking any technical documentation or new information, reverses its own finding of the wide availability of geologic storage. In particular, the Proposal suggests that several decades of research behind the NATCARB Atlas and related NETL Carbon Storage Program, and data accessible through the NETL EDX (Energy Data Exchange) databases, is insufficient to assure widely available sequestration opportunities for CO_2 captured at coal-fired power plants. [264] [265] To the contrary, the NATCARB Atlas, now in its fifth version, is founded on two decades of research and demonstrations in regions across the U.S., including hundreds, if not thousands of technical publications based on millions of tons of CO_2 injected into saline aquifers and depleted oil fields.[266] While, as explained above, the Clean Air Act does not require that storage is demonstrated economically and geographically available in every part of the U.S., the data underpinning the Atlas, combined with a decades of experience of CO_2-EOR and supercritical CO_2 pipeline know-how demonstrate that geologic storage resources are widely accessible, particularly in the regions where coal plants are likely to be constructed.

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[261] *Brookings Municipal Tel. Co. v. FCC*, 822 F.2d 1153, 1169 (D.C. Cir. 1987) (internal citations omitted).
[262] EPA, Response to Comments, Legal Issues, at 2-58, Doc. ID: EPA-HQ-OAR-2013-0495-11861 (Oct. 23, 2015); *see also id.* at 2-64 "It is also not clear that the issue of geographic constraints can be raised in the absence of any indication or objective indicia that an affected source would locate there."
[263] 83 Fed. Reg. at 65,441.
[264] NETL, *Carbon Storage Program*, (May 2017), https://www.netl.doe.gov/sites/default/files/2017-11/Program-116.pdf.
[265] NETL, *NARCARB Viewer 2.0*, https://edx.netl.doe.gov/geocube/#natcarbviewer (last visited May 15, 2019).
[266] NETL, *NATCARB/Atlas*, https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas (last visited May 15, 2019); NETL, *Carbon Storage Atlas 5th Edition* (2015), https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

ii. The U.S. Geologic Survey 26 Basin Study provides a detailed storage assessment.

As cited in 2015, and overlooked in the Proposal, the U.S. Geological Survey, in 2013, published an important technical assessment of accessible storage resources for CO_2 for twenty-six sedimentary basins in the onshore areas and state waters of the U.S.[267] The assessment was based on current geologic subsurface knowledge, including the hydrogeologic properties of reservoir formations potential. The assessment estimates available storage capacity of 3,000 metric gigatons of capacity, representing over half a millennium's worth of today's total energy-related CO_2 emissions. The assessment did not incorporate federally owned offshore areas. The estimates, based on 2012 data, totaled the mappable volume of rock including an adequately porous reservoir and a regional sealing formation, between 3,000 and 13,000 feet deep. The sedimentary basins represented eight regions of the U.S. and identified 202 geologic storage units. Storage units that did not have adequate data for robust geologic modeling were left out and no storage resources were estimated. Two types of geologic storage were identified, buoyant trapping—trapped by a caprock or stratigraphy—and residual—trapped by capillary processes in rock pores, separated into three different classes based on reservoir permeability.

Figure 1: USGS National Assessment of Geologic Carbon Dioxide Storage Reserves

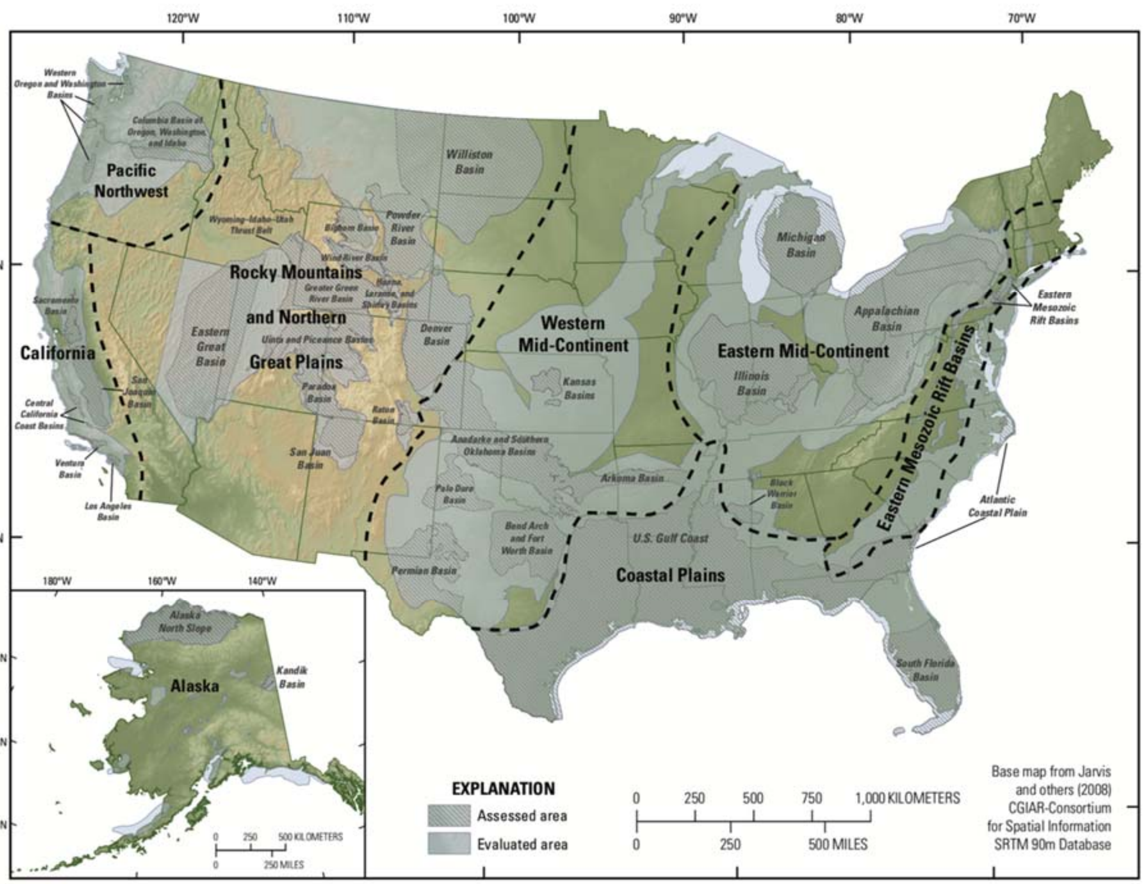

Image Source: U.S. Geological Survey

[267] USGS Geologic Carbon Dioxide Storage Resources Assessment Team, *National Assessment of Geologic Carbon Dioxide Storage Resources: Summary*, USGS (Sept. 2013), https://pubs.usgs.gov/fs/2013/3020/.

iii. The Gulf Coast Carbon Center National Carbon Storage Database provides data for 21 basins.

EPA's documentation accompanying this Proposal is incomplete as it fails to include the University of Texas Gulf Coast Carbon Center (GCCC) database. In 2013, GCCC published a detailed subsurface assessment of saline sequestration resources selected to be appropriate for commercial volumes of CO_2 sequestration.[268] The geographic region covered by this database strongly overlaps with existing coal-fired electric generating units and coal resources. It is highly likely that any newly constructed coal power plants would be sited in the region of existing plants because of 1) the existing coal handling and transportation infrastructure and attendant technical support facilities, 2) proximity to mine-mouth coal, and 3) proximity to sedimentary formations associated with coal deposits that would be most likely to be available for sequestration.

The GCCC database provides a technical assessment of twenty-one basins characterized by nineteen technical metrics. This assessment provides, in many cases, greater detail than the NATCARB Atlas version V. The highly detailed database includes hydrogeologic metrics needed to determine the suitability of a saline brine aquifer for commercial volumes of carbon storage. Basins are accompanied by a description of the resource, references, and sources of information, and appropriate sequestration formations. Metrics include key parameters needed to assess the availability of commercial-scale storage: depth, permeability and hydraulic conductivity, formation thickness, net sand thickness, percent shale, continuity, top seal thickness, top seal continuity, hydrocarbon production, fluid residence time, flow direction, CO_2 solubility, rock water chemical reaction, porosity, water chemistry, and rock mineralogy.

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[268] Univ. of Tex. Bureau of Econ. Geology Gulf Coast Carbon Ctr., *CO_2 Brine Database* (2013), http://www.beg.utexas.edu/gccc/co2-data/data-main.

Figure 2: CO2 Brine Database – Brine Formation Atlas, 2013

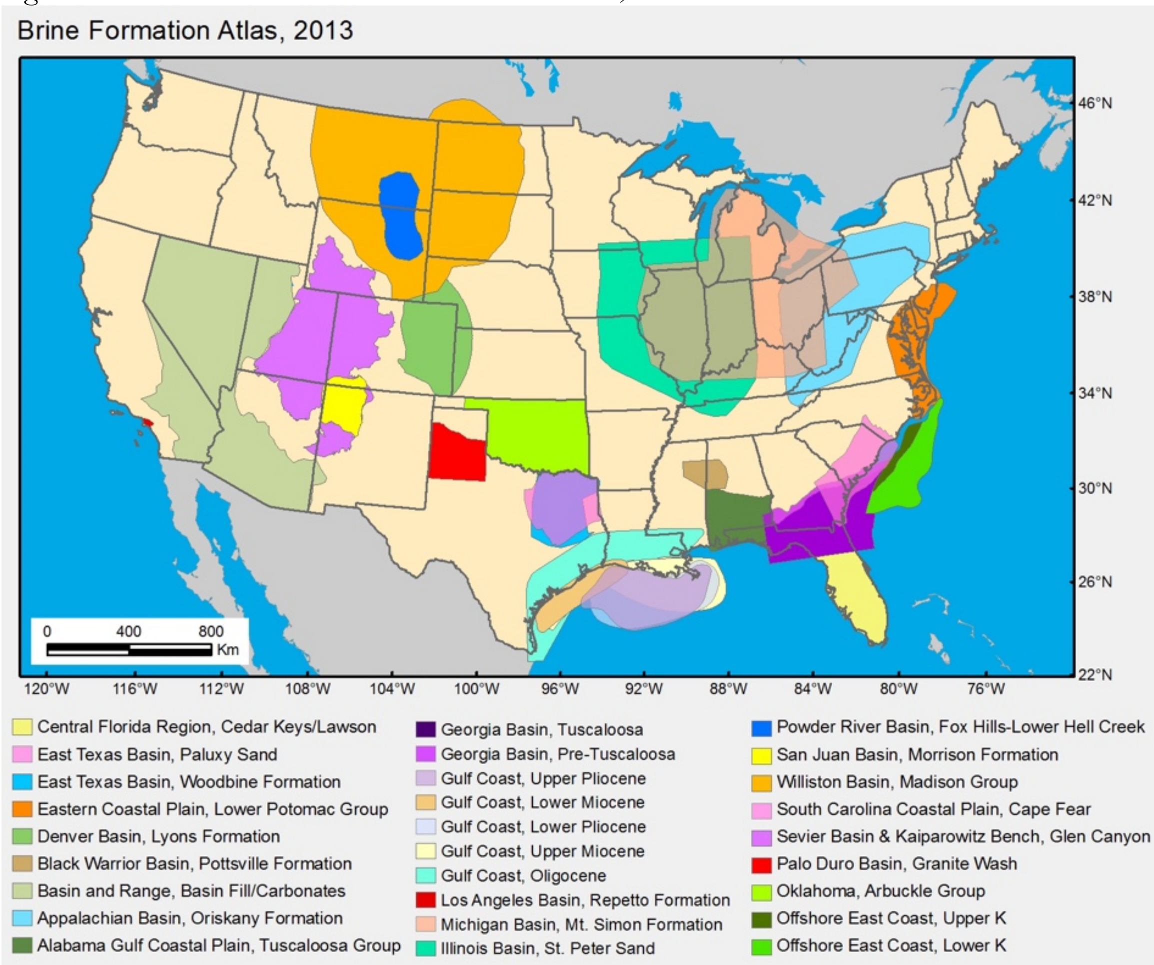

Image Source: University of Texas Bureau of Economic Geology GCCC

iv. EPA mischaracterizes saline storage and its availability.

Without any accompanying technical analysis, the Proposal claims that "…despite showing large potential, saline storage has not yet been demonstrated to be available, both from a geographical perspective as well as economically, at all locations."[269] This statement, however, ignores the large body of research on saline geologic storage, and the long track record of underground injections.[270] This body of research firmly underpins EPA's 2015 determination[271] that "[geologic sequestration] in deep saline formations is demonstrated"[272] and "widely available."[273]

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[269] 83 Fed. Reg. at 65,442.

[270] EPA, Geographic Availability of Geologic Sequestration Memorandum, at 2, Doc. ID: EPA-HQ-OAR-2013-0495-11941 (Dec. 2018).

[271] *See generally* 80 Fed. Reg. at 64,578-79.

[272] *Id.* at 64,588.

[273] *Id.* at 64,576.

The current standards are based on a robust record of technical support showing that saline storage is adequately demonstrated and available. The 2015 record contains, for example:

- Detailed regional subsurface injection tests and assessments from the completed NETL Regional Carbon Sequestration Partnership projects such as the prolific SECARB Texas BEG Cranfield project which injected over 5 million tonnes of CO_2 into the saline water leg of the producing formations geologic structure over the life of the project.[274] [275]
- BEG working saline storage database which describes multiple opportunities for commercial-scale saline storage in twenty-one basins across the U.S., described elsewhere in these comments.[276]
- Results of U.S. Geologic Survey basin analysis from 2013 described above. [277]
- An understanding of stacked saline storage, where CO_2 may be injected, using existing infrastructure, for sequestration into non-hydrocarbon-bearing saline formations that may exist above or below producing intervals in EOR fields, as described elsewhere in these comments.[278]
- A demonstration that pipelines combined with storage hubs may provide the infrastructure to sequester large volumes of CO_2 in regional saline geologic reservoir storage facilities. As described elsewhere in these comments in more detail, results of regional onshore and offshore storage hub investigations are being reported as part of the 2016 CarbonSAFE initiative. For example, onshore storage projects at Kemper County Mississippi hub project, the Mid-Continent stacked storage project, and the Gulf Coast offshore project and offshore investigations of the Northeast US. [279] [280] [281] [282]

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274 Susan D. Hovorka, Timothy A. Meckel & Ramón H. Treviño, *Monitoring a Large-Volume Injection at Cranfield, Mississippi: Project Design and Recommendations*, 18 INT'L J. OF GREENHOUSE GAS CONTROL 345 (2013), https://www.academia.edu/22567245/Monitoring_a_large-volume_injection_at_Cranfield_Mississippi_Project_design_and_recommendations.

275 Univ. of Tex. Bureau of Econ. Geology Gulf Coast Carbon Ctr., *Cranfield Log: Project Overview,* http://www.beg.utexas.edu/gccc/research/cranfield (last visited Mar. 15, 2019).

276 Katherine Romanak, Univ. of Tex. Bureau of Econ. Geology Gulf Coast Carbon Ctr., *SECARB Phase III Cranfield Project (Early Test)* (Mar. 8, 2018), https://www.sseb.org/wp-content/uploads/2018/03/Romanak_SECARB18.pdf.

277 USGS Geologic Carbon Dioxide Storage Resources Assessment Team, *National Assessment of Geologic Carbon Dioxide Storage Resources: Summary*, USGS (Sept. 2013), https://pubs.usgs.gov/fs/2013/3020/.

278 Stuart Coleman, Gulf Coast Carbon Ctr., *The Geologic and Economic Analysis of Stacked CO2 Storage Systems: A Carbon Management Strategy for the Texas Gulf Coast* (2010), http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=314.

279 David Riestenberg, DOE, *CarbonSAFE: Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S* (Aug. 2018), https://www.osti.gov/servlets/purl/1476351.

280 Susan D. Hovorka, et al., *supra* note 274.

281 Andrew Duguid, Battelle Mem'l Inst., *Integrated Mid-Continent Stacked Carbon Storage Hub Phase I Final Report*, (Oct. 2018) https://www.osti.gov/servlets/purl/1478726.

282 Lydia Cumming et al., *Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment*, 114 ENERGY PROCEDIA 4629 (2017), https://reader.elsevier.com/reader/sd/pii/S1876610217317848?token=2E44BBA592EFEF3DCDE705CE62D88A8512E23AC3FF6A167B9FC73B597CA80C04977AEB5B0FFAD6D7D2EB2ED9C7768470.

EPA's unsupported attempt to undermine the proven availability of saline storage demonstrates EPA's poor grasp of the current technical basis underlying the current standards. As described below, confidence in saline storage technology comes from many areas including the long history of large volumes of natural gas storage in deep geologic formations including saline reservoirs; billions of tons of liquid waste injected into saline aquifers annually; several decades of work by the regional carbon sequestration partnerships; storage hub studies emerging from the CarbonSAFE initiative; large offshore storage assessments; mapping and assessments by the U.S. Geologic Survey; and of course ADM's two Illinois Basin projects combined with commercial international saline projects such as Sleipner, In-Salah and Aquistore.

Injections into saline aquifers, salt domes, and depleted gas zones have been routine for decades as a part of America's natural gas storage program. In fact, natural gas storage goes back a century, originally tested in 1915.[283] The National Petroleum Reserve system, see Figure 3, now safely contains and maintains 2.5 trillion cubic feet of injected gas in the subsurface on an annual basis.[284] Natural gas storage in geologic formations is, in fact, widespread, with natural gas storage facilities in 30 states, in approximately 400 facilities nationwide, with a combined capacity of about 4 trillion cubic feet of natural gas. Eighty percent of the deep geologic natural gas storage capacity is in depleted oil and gas formations—which themselves are porous formations containing hydrocarbon bearing saline brines, 10 percent in saline brine-only aquifers, and 10 percent in salt formations. [285]

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[283] Nate Alleman, *A Look at Natural Gas Storage Operation and Regulation in the United States*, GWPC 2016 UIC Conference (Feb. 2016), http://www.gwpc.org/sites/default/files/event-sessions/Alleman_Nathan.pdf.

[284] EIA, *Weekly Natural Gas Storage Report*, *supra* note 242.

[285] API, *Underground Natural Gas Storage: Facts and Figures*, https://www.aga.org/globalassets/underground_storage_background_final.pdf (last visited Mar. 15, 2019).

Figure 3: U.S. Underground Natural Storage Facility, by Type (December 2017)

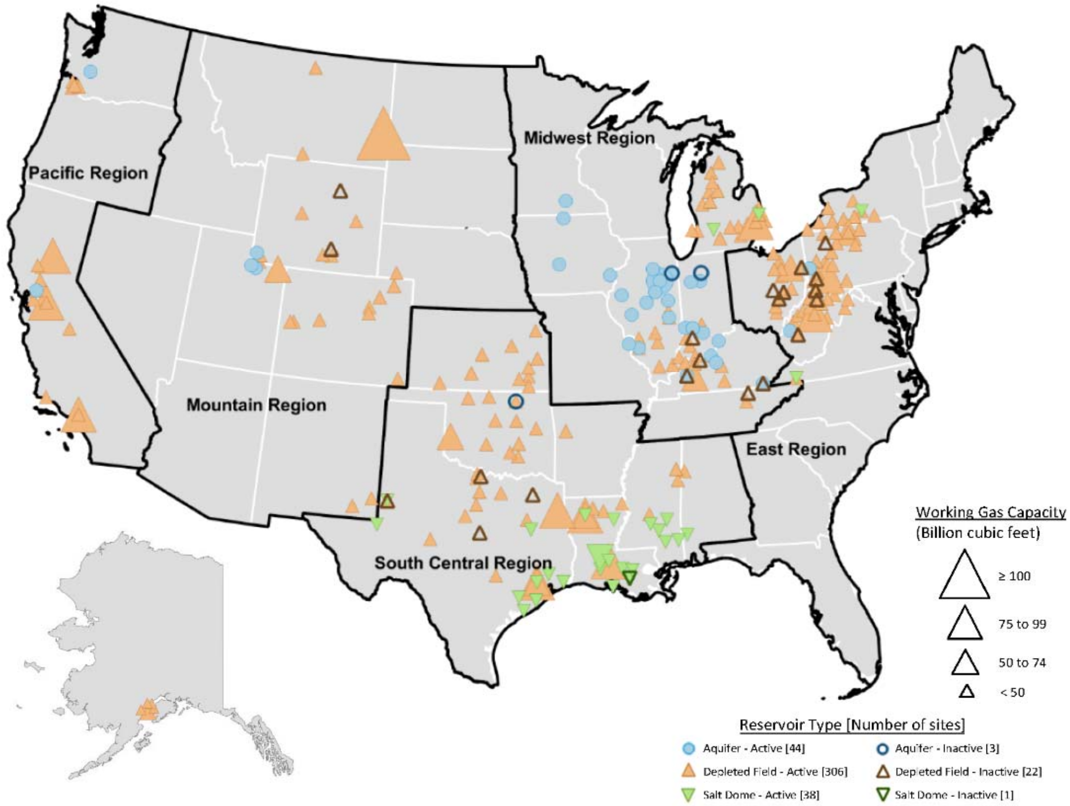

Image Source: U.S. Energy Information Administration[286]

Furthermore, *billions* of tons of liquid waste are disposed of into saline aquifers annually.[287] There are approximately 150,000 injection wells in the U.S. in use for disposal of municipal wastewater, produced fluid brine waste from natural gas storage, unconventional gas production and brines produced during EOR. Moreover, the know-how for injecting CO_2 into saline brine formations is proven by approximately 1.4 billion tons of new (and much more recycled) CO_2 injected into porous sandstone and carbonate formations containing oil-bearing brines for EOR.

EPA incorrectly characterizes the Decatur project(s) as in its "early stages," and asserts that Decatur does not provide proof that carbon storage is available at commercial-scale at all locations.[288] In fact, the two Decatur projects have already provided results that demonstrate that storage is available in the Illinois Basin, a geologic region within which coal may be easily sourced and therefore offers the potential for the siting of mine-mouth coal-fired power plants. The first of the two sister Decatur projects, the Illinois Basin Decatur Project, proved that one million tonnes of CO_2, a commercial volume of CO_2 to be sure, could be safely stored in the region's deep saline aquifers. The second

[286] EIA, *U.S. Underground Natural Gas Storage Facility: by Type* (Dec. 2017), https://www.eia.gov/naturalgas/ngqs/images/storage_2018.png.
[287] Elizabeth J. Wilson, Timothy L. Johnson & David W. Keith, *Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage*, 37 ENVT'L SCI. & TECH. 3476 (2003), https://pubs.acs.org/doi/pdf/10.1021/es021038%2B.
[288] 83 Fed. Reg. at 65,442.

project, the Illinois Industrial CCS project project is underway injecting and storing one million tonnes of CO_2 per year with a five-year permit to inject 5.5 Mt projected over the life of the project.[289] [290] This is in line with EPA's own EIA which indicates that a 600 MW power plant would have to capture 1.1 million short tons - just under 1 million tonnes – to meet the standard.[291]

EPA rejected claims in 2015 that geologic sequestration was not demonstrated for the large volume of CO_2 that would be captured from power plants.[292] The Agency pointed to the construction permits issued under Class VI for a steam generating power plant, which would not have been issued without demonstrating that the volume of CO_2 could be securely contained.[293] Next, EPA pointed to large scale saline storage projects sequestering volumes of CO_2 comparable to those expected from a power plant project.[294] Projects in Norway, Algeria and, Canada have injected and stored a total of over 26 Mt of CO_2 through 2017:

- 17 Mt of CO_2 injected and monitored at Sleipner and 5 Mt of CO_2 injected and monitored at Snohvit projects in Norway. [295] [296]
- 3.8 Mt of CO_2 injected and monitored at In Salah project in Algeria. [297]
- Over 100,000 tonnes of CO_2 injected between 2015 and 2017, comprehensively monitored, underpinned by eighteen years of R&D and demonstration at Aquistore Saskatchewan Canada proving up capacity for gigatons of CO_2 storage. [298] [299]

EPA may not ignore relevant information in its rulemaking process.[300] The record definitively proves that saline storage is adequately demonstrated and available to store large volumes of CO_2 from power plant CCS projects. Any other conclusion would be "counter to the evidence before the agency" and arbitrary and capricious.[301]

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289 ADM, *ADM Begins Operations for Second Carbon Capture and Storage Project* (April 7, 2017), https://www.adm.com/news/news-releases/adm-begins-operations-for-second-carbon-capture-and-storage-project-1.
290 Scott McDonald, Ill. Industrial Carbon Capture & Storage Project, *Eliminating CO2 Emissions from the Production of Biofuels: A 'Green' Carbon Process,* https://www.energy.gov/sites/prod/files/2017/10/f38/mcdonald_bioeconomy_2017.pdf.
291 2018 EIA, at 2-3.
292 80 Fed. Reg. at 64,588-89.
293 *Id.* at 64,588.
294 *Id.*
295 Philip S. Ringrose, *The CCS Hub in Norway: Insights from 22 Years of Saline Aquifer Storage*, 146 ENERGY PROCEDIA 166 (2018), https://doi.org/10.1016/j.egypro.2018.07.021.
296 Anne-Kari Furre et al., *20 Years of Monitoring CO_2-Injection at Sleipner*, 114 ENERGY PROCEDIA 3916 (2017), https://doi.org/10.1016/j.egypro.2017.03.1523.
297 Philip S. Ringrose, *supra* note 295.
298 Aquistore, *Aquistore Project Annual Report* (2016), http://aquistore.ca/+pub/AQ%20Annual%20Report%202016%20Final.pdf.
299 Kyle Worth, Petroleum Tech. Research Ctr., *Aquistore*, https://www.aiche.org/system/files/aiche-proceedings/conferences/404771/papers/488230/P488230.pdf (last visited Mar. 15, 2019).
300 *Bellsouth Telecomms., Inc. v. FCC*, 469 F.3d 1052, 1060 (D.C. Cir. 2006) ("deference owed agencies' predictive judgments gives them no license to ignore the past when the past relates directly to the question at issue); *see also Mississippi v. EPA*, 723 F.3d 246, 269 (D.C. Cir. 2013) (agency must explain why evidence submitted is not reliable if they choose to ignore it); *NRDC*, 902 F.2d at 971 (same).
301 *State Farm*, 463 U.S. at 43 (internal citations omitted).

v. Very large Eastern U.S. and Gulf Coast offshore geologic storage could store trillions of tonnes of CO_2.

Offshore storage, which is not fully considered in the Proposal, holds promise to receive large quantities of captured CO_2 for EOR and saline storage. It can be envisioned that a network of pipelines leading to a trunk line to the Gulf could store CO_2 from a wide region in the U.S. Offshore storage offers several important advantages:

- Offshore formations are thicker, porous, and more ductile, less prone to fracture and more likely to accommodate CO_2;
- Storage sites are distant from populated areas;
- Offshore geologic resource leasing is less complex;
- Pipelines will be easier to route;
- There are no USDWs in the offshore, and, moreover, leakage of CO_2 and brine (concentrated seawater) into the ocean may pose a lesser environmental risk (if unaccompanied by hydrocarbons); and
- Softer sedimentary rocks on the continental shelf minimize the risk of damaging induced seismicity.

In 2012, ICF International, for the BOEM Outer Continental Shelf Study, analyzed U.S. offshore storage options in the U.S. Outer Continental Shelf, where there are very large carbon storage resources - an estimated 3.6 trillion metric tonnes. The report includes costs for the construction of pipelines and provides estimates for several example cases.[302] The study concluded that there would be a $16.9B benefit to the U.S. economy for storing CO_2 on the Outer continental shelf.

According to a 2014 assessment by ARI for NETL, 310 Mt to 3.9 Gt of CO_2 could be utilized and stored at a low cost in the process of EOR in the offshore Gulf of Mexico, one of the world's largest and thickest porous sedimentary sequences.[303] [304]

The GCCC at the University of Texas, Austin has recently mapped and begun the process of estimating the magnitude of large geologic carbon storage formations in the offshore saline formations and gas fields of the Gulf of Mexico. In 2018, the Center released an atlas of storage opportunities in Miocene age strata of the Gulf Coast and concluded that hundreds of millions of tonnes could be sequestered in those thick sandstone sequences alone.[305]

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302 Harry Vidas et al., ICF Int'l, *Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf* (2012) https://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/External_Studies/OCS%20Sequestration%20Report.pdf.

303 NETL, DOE, *CO_2 – EOR Offshore Resource Assessment* (June 1, 2014), https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=626.

304 Ramon Trevino & Tip Meckel, *Geological CO_2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters* (2017), https://store.beg.utexas.edu/reports-of-investigations/3415-ri0283-atlas.html?search_query=RI0283&results=2 (Attach. F).

305 *Id.*

Modeled offshore pipeline buildout scenarios demonstrate that the Gulf Coast could serve as a hub for storing CO_2 from energy and industrial production in the U.S.[306] The analysis concluded that for a total capital cost of $6 billion dollars, there is a potential to store 40 Mtpa in 52 oil fields in the shallow Gulf of Mexico through a three pipeline system, and store 57 Mtpa in 63 large oil fields also connected by a three pipeline system in the deep Gulf of Mexico.

Battelle Memorial Institute received a $4.7 million grant in 2015 to lead a consortium to investigate geologic storage opportunities in the Northeast U.S including the Baltimore Canyon Trough and the George's Banks Basin.[307] The effort includes mapping the geologic formations in the subsurface using existing well logs and seismic methods, investigating the hydrogeology by testing existing geologic cores. The results suggest that three deep saline reservoir formations, representing thousands of feet of thickness, such as the Mississauga Formation, exist in the offshore overlain by thick mud caprock that, combined, may be able to store large quantities of CO_2, providing a permanent geologic sink for the hundreds of millions to billions of tonnes of CO_2 generated by coal plants in the Northeast region.[308] Initial results of the study suggest that these formations have the capacity, permeability, porosity, and requisite depth for commercial-scale geologic carbon storage.

Figure 4: Battelle Mid-Atlantic Offshore Carbon Resources Assessment Region

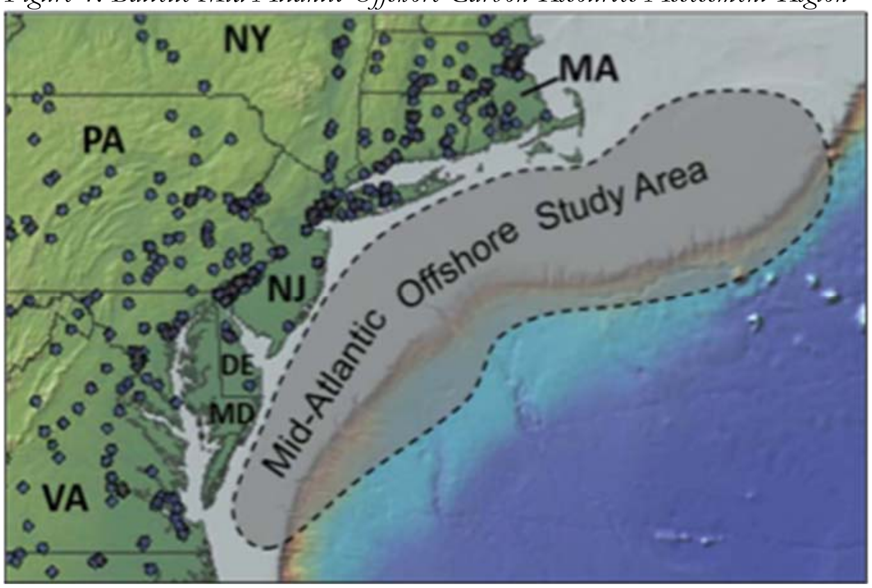

Image Source: Cumming et al. 2017

vi. The Proposal fails to describe the full potential of incidental CO_2 storage during the process of CO_2-EOR and storage in associated saline formations.

Carbon dioxide injected during EOR is stored in the process of injection, production, and recycling. This "incidental" or "associated" storage occurs when CO_2 is trapped in rock pore spaces by capillary physics the process of releasing oil during CO_2 flooding. Indeed, EPA's 2015 rule describes the potential for CO_2 storage in depleted oil fields. Yet this Proposal falls short of describing the full

[306] Vello Kuuskraa, Advanced Resources Int'l, Inc., *Establishing CO_2 Utilization, Storage and Pipeline Systems for Oil Fields in Shallow and Deep Waters of the Gulf of Mexico* (June 19, 2017), https://www.osti.gov/servlets/purl/1469161.
[307] Lydia Cumming et al., *supra* note 282.
[308] *Id.*

potential of these fields and overlooks the potential for storage of CO_2 in associated brine reservoirs—non-petroleum bearing intervals in the same fields. Finally, EPA's Proposal makes no mention of storage potential in residual oil zones (ROZ) where they may exist.

EOR storage offers some advantages over storage in saline formations: 1) the EOR industry possesses long experience in managing, injecting and tracking injected CO_2, and possesses the know-how to manage CO_2 projects; 2) depleted oil fields with long operating histories offer known reservoir capacities, injectivities, and other characteristics, and can *today* accept large volumes of CO_2 for tertiary oil production and subsequent storage; 3) EOR fields are generally equipped with the facilities to manage and inject CO_2; 4) oil fields are proven geologic traps by nature, known for their ability to hold oil and gas for millions of years; 5) multiple injection and production wells offer the potential to manage the subsurface CO_2 plume; 6) the opportunity for stacked storage in associated saline water-bearing formations in the EOR fields enhances local storage capacity and storage options; and 7) the added revenues from EOR can drive investment in CO_2 capture, transportation, injection, and monitoring infrastructure, which can be transferred to saline sequestration at a potentially lower cost than in greenfield saline sequestration.[309]

In 2014, the last year for which data is available, there were approximately 134 CO_2-EOR projects actively injecting CO_2 in the deep subsurface.[310] DOE has estimated that there are over 1,600 oil fields, with a total of 146 billion barrels of oil places where CO_2-EOR could be applied.[311] ARI estimates that next generation EOR combined with current estimates of ROZs could produce a demand for approximately 33 billion metric tons of CO_2.[312] Currently, there are an estimated 2-3 billion metric tons of naturally occurring CO_2 available to meet this demand.[313] The remaining demand must be made up of captured sources of CO_2.

So-called "next-generation+" techniques would take EOR to the next level, with the advantage of monitoring and surveillance technology, improving the ability to utilize CO_2 for producing oil along with increasing the potential to utilize and store much greater volumes of CO_2 in oil fields while utilizing the same subsurface methods to monitor and ensure storage of the injected CO_2.[314] [315]

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309 Bruce Hill et al., supra note 61, at 6,811.

310 Vello Kuuskraa & Matt Wallace, *CO_2-EOR Set for Growth as New CO_2 Supplies Emerge*, 112 OIL & GAS J. 66 (2014), https://www.adv-res.com/pdf/CO2-EOR-set-for-growth-as-new-CO2-supplies-emerge.pdf.

311 *See* NETL, DOE, *Development of Novel Methods for CO2 Flood Monitoring*, E&P Focus (2012), https://www.netl.doe.gov/file%20library/research/oil-gas/epnews-2012-spring.pdf (Attach. G).

312 Vello Kuuskraa, *Using the Economic Value of CO2 EOR to Accelerate the Deployment of CO_2 Capture, Utilization and Storage (CCUS)* (Apr. 2012), https://hub.globalccsinstitute.com/publications/proceedings-2012-ccs-cost-workshop/using-economic-value-co2-eor-accelerate-deployment-co2-capture-utilization-and-storage-ccus.

313 Vello A. Kuuskraa, Tyler Van Leeuwen & Matt Wallace, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2 – Enhanced Oil Recovery (CO_2–EOR)* (2011), https://www.netl.doe.gov/energy-analysis/details?id=569.

314 Vello A. Kuuskraa, Phil Dipietro & John Litynski, *The Synergistic Pursuit of Advances in MMV Technologies for CO_2 – Enhanced Recovery and CO_2 Storage*, 37 ENERGY PROCEDIA 4099 (2013), https://www.sciencedirect.com/science/article/pii/S1876610213005547 (discussing "five case studies of using MMV technology and smart wells to monitor and manage CO_2 storage and CO_2-EOR operation").

315 Matthew Wallace, Vello A. Kuuskraa & Phil Dipietro, *An In-Depth Look at "Next Generation" CO_2-EOR Technology* (Sept. 2013), https://www.netl.doe.gov/projects/files/FY14_AnInDepthLookatNextGenerationCO2EORTechnology_090113.pdf.

ROZs, a recently commercialized next-generation EOR strategy, are increasing the demand for CO_2.[316] ROZs are naturally artesian water-flushed oil reservoirs where residual oil can be produced utilizing CO_2 whether there is a conventional production zone overlying the ROZ or not.[317] Commercial-scale ROZs have been proven in West Texas (e.g. Kinder Morgan's Tall Cotton field) and identified elsewhere such as in Wyoming. Shell first identified and produced ROZs in its West Texas Wasson field, which was later taken over by Occidental.[318] Now a half-dozen or more companies including Hess, Kinder Morgan, Occidental, XTO, Chevron, and several others, are currently applying or planning to apply CO_2-EOR technologies to ROZ.[319] Another early player, Hess, launched its ROZ plays in 1996 and expanded those operations in 2004 and 2007.[320]

Figure 5: Illustration showing ROZs below existing oil fields. ROZs may also exist where there is no conventional production interval.

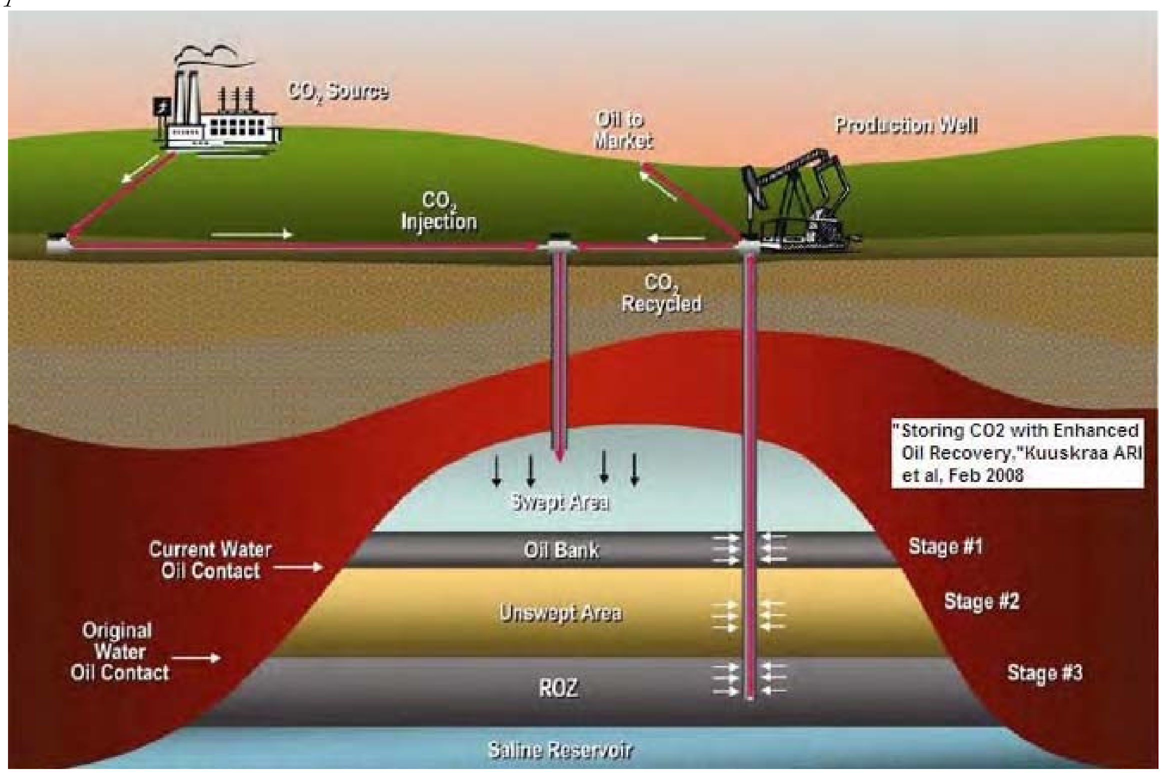


Image Source: Advanced Resources International[321]

[316] *See* ROZ Study Group, *Reference Material: Worldwide ROZs*, http://residualoilzones.com/reference-material-worldwide-rozs/ (last visited Mar. 15, 2019).
[317] Vello A. Kuuskraa, Michael L. Godec & Phil Dipietro, *CO_2 Utilization from "Next Generation" CO_2 Enhanced Oil Recovery Technology*, 37 ENERGY PROCEDIA 6854 (2013), https://www.sciencedirect.com/science/article/pii/S1876610213008618.
[318] Vello Kuuskraa & Matt Wallace, *supra* note 310.
[319] *See* Vello Kuuskraa, *QC Updates Carbon Dioxide Projects in OGJ's Enhanced Oil Recovery Survey*, 110 OIL & GAS J. 72 (2012), https://www.ogj.com/articles/print/vol-110/issue-07/drilling-production/qc-updates-carbon-dioxide-projects.html (Attach. H).
[320] Vello Kuuskraa & Matt Wallace, *supra* note 310.
[321] Vello A. Kuuskraa, Michael L. Godec & Phil Dipietro, *supra* note 317.

Another potential storage opportunity takes advantage of existing infrastructure for EOR to store CO_2 in geologic formations that are associated with producing formations. This is called "stacked" saline storage, a concept that has been proposed for over a decade.[322] In oil fields, the characteristic sedimentary sequences often include repeating layers of interbedded sandstone and mudstone that represent opportunities for storing CO_2. Stacked storage takes advantage of these repeating sequences of geology to build storage capacity vertically. *See* illustration below. Utilizing multiple formation sections for storage is advantageous because injected CO_2 may be spread out throughout the geologic section instead of creating one large single CO_2 plume. Also, commercial pipelines and injection facilities used for EOR may now be repurposed for saline storage within the EOR fields. Stacked geologic carbon storage may be an opportunity to store CO_2 at a lower cost because of the existing facilities which could reduce cost at the outset.

In summary, the long commercial experience with deep geologic CO_2 injection, the continuously expanding infrastructure that accompanies CO_2-EOR, accompanied by the rising demand for CO_2, renders oil fields a viable and widespread option for sequestering a large volume of CO_2 captured from power plants in the U.S.

Figure 6: Illustration of Stacked Saline Storage

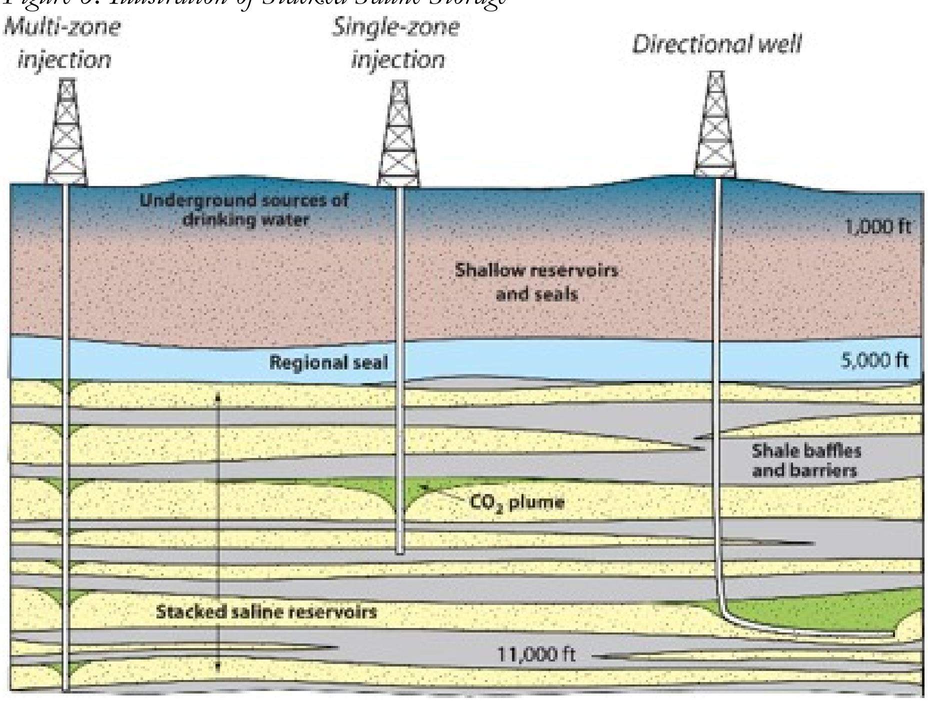


Image Source: J.C. Pashin et al., Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III: Final Report prepared for Advanced Resources International, at 57 (2008)

322 Stuart Coleman, *supra* note 278.

Figure 7: Illustration of Layered Oil, Gas and Saline Formations at the SECARB Frio Project, Texas

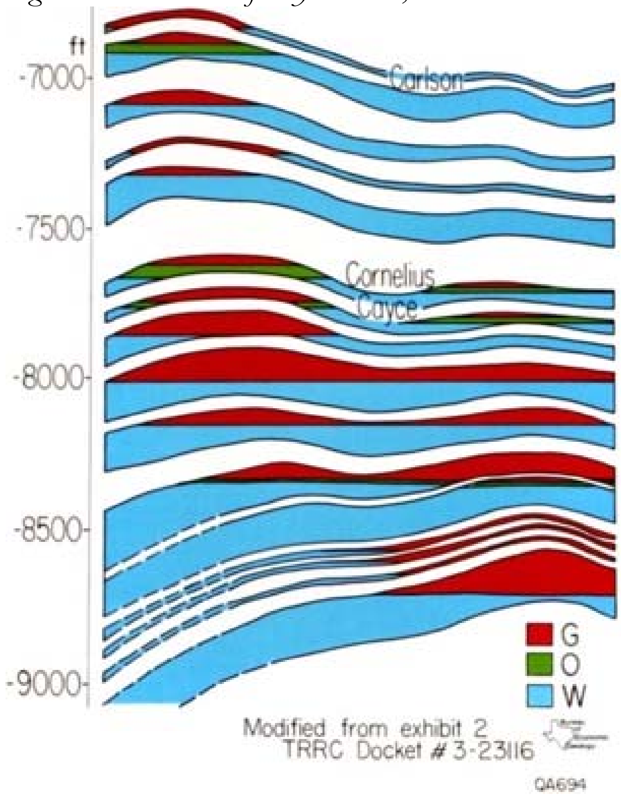


Image Source: Susan Hovorka, TX BEG modified from Noel Tyler and William A. Ambros, Facies architecture and production characteristics of strand plain reservoirs in North Markham – North Bay City Field, Frio Formation, Texas, 70 AAPG BULL. 809-829 (July 1986)

vii. A decade long NETL CarbonSAFE Initiative is actively developing CO_2 sequestration hub potential.

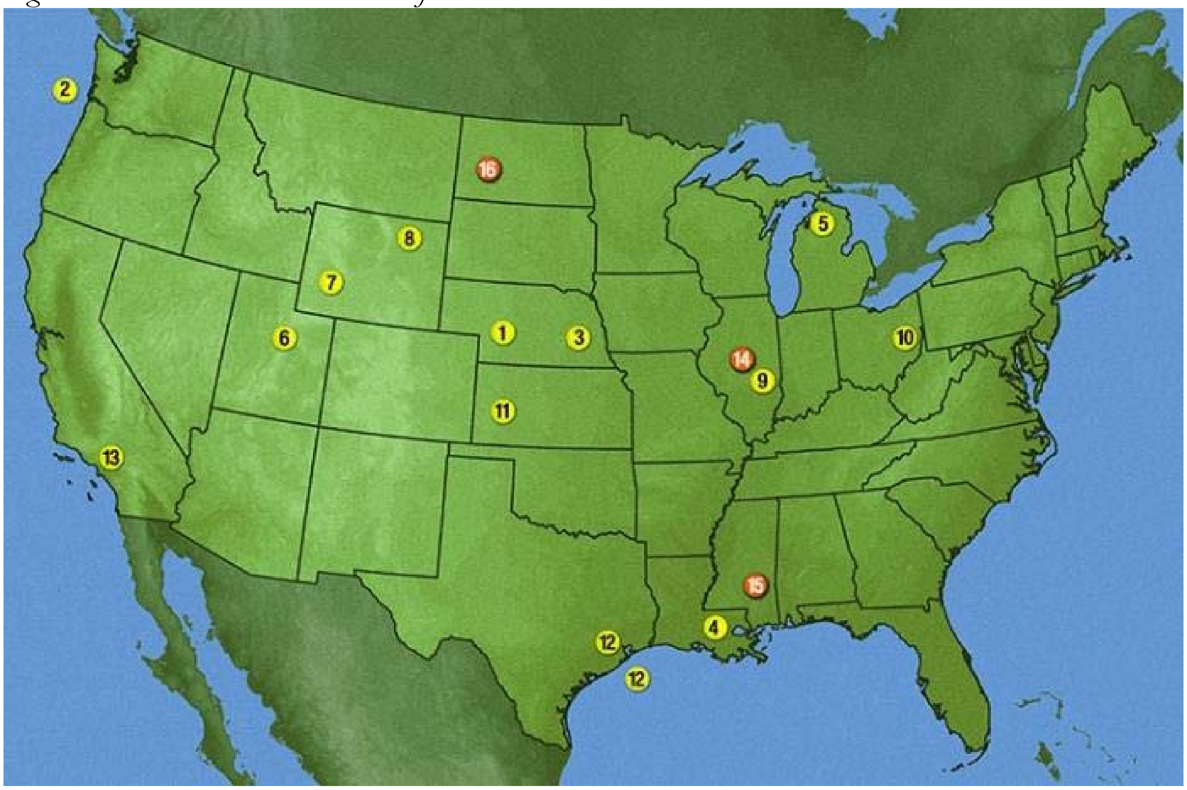
In its Proposal, EPA acknowledges the DOE CarbonSAFE program, stating that "work on the DOE Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative, an effort to develop an integrated CCS storage complex constructed and permitted for operation in the 2025 timeframe, will increase understanding of the feasibility of GS across the United States and further characterize the availability of GS." [323]

Indeed, in late 2016, DOE, in a follow-up to the successful decade-long Regional Carbon Storage Partnerships (RCSP) effort, initiated a new phase of its efforts to advance carbon storage technology. However, as described below, an effort has already begun to produce very important findings, consequential to this rulemaking that demonstrate available storage. Moreover, the Agency cannot reject relevant information because it believes that it may be updated at some uncertain future time.[324]

[323] 83 Fed. Reg. at 65,442.
[324] *Chlorine Chem. Council v. EPA*, 206 F.3d 1286, 1290-91 (D.C. Cir. 2000).

In November 2016, DOE launched the "CarbonSAFE" program by awarding $44 million to support and promote the development of carbon storage sites with the potential to store over 50 Mt of CO_2 by 2026, building on learning from its RCSP program.[325] [326] In addition, the RCSP program may also be reinvigorated in 2019. There are sixteen CarbonSAFE storage projects currently receiving federal funding as illustrated in the table below.

Figure 8: CarbonSAFE Initiative Project Locations



[325] *See* NETL, DOE, *CarbonSAFE*, https://www.netl.doe.gov/research/coal/carbon-storage-1/storage-infrastructure/carbonsafe (last visited Mar. 15, 2019).
[326] *See* NETL, DOE, *Energy Department Announces More than $44 Million for CO_2 Storage Projects* (Nov. 30, 2016), https://www.energy.gov/articles/energy-department-announces-more-44-million-co2-storage-projects.

Table 2: List of NETL CarbonSAFE Projects as of September 2018

	Pre-Feasibility Project Title	Project Number
1	Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study	FE0029186
2	Integrated Pre-Feasibility Study for CO_2 Geological Storage In The Cascadia Basin, Offshore Washington State And British Columbia	FE0029219
3	Integrated Mid-Continent Stacked Carbon Storage Hub	FE0029264
4	Integrated Carbon Capture and Storage in The Louisiana Chemical Corridor	FE0029274
5	Northern Michigan Basin CarbonSAFE Integrated Pre-Feasibility Project	FE0029276
6	CarbonSAFE Rocky Mountain Phase I: Ensuring Safe Subsurface Storage Of Carbon Dioxide In The Intermountain West	FE0029280
7	Integrated Pre-Feasibility Study of A Commercial-Scale Commercial Carbon Capture Project In Formations Of The Rock Springs Uplift, Wyoming	FE0029302
8	Integrated Commercial Carbon Capture and Storage Prefeasibility Study At Dry Fork Station, Wyoming	FE0029375
9	CarbonSAFE Illinois East Sub-Basin	FE0029445
10	CAB-CS: Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project	FE0029466
11	Integrated Carbon Capture and Storage in Kansas	FE0029474
12	Integrated CCS Pre-Feasibility in The Northwest Gulf Of Mexico	FE0029487
13	California CO_2 Storage Assurance Facility Enterprise (C2SAFE)	FE0029489
	Feasibility Project Title	**Project Number**
14	CarbonSAFE Illinois Macon County	FE0029381
15	Establishing An Early Carbon Dioxide Storage (ECO_2s) Complex In Kemper County, Mississippi: Project ECO_2S	FE0029465
16	North Dakota Integrated Carbon Storage Complex Feasibility Study	FE0029488

There are two phases of funded CarbonSAFE projects: Phase I: Pre-Feasibility studies in Wyoming, Illinois, Texas Gulf Coast, Utah, Nebraska, Kansas, Rocky Mountains, Washington State (onshore and offshore) Central Appalachian Basin, California, North Dakota, and Louisiana, and, Phase II: Storage complex feasibility studies in Mississippi, North Dakota, and the Illinois Basin.

One important Phase II CarbonSAFE project is already showing promise as an option to be a major hub for geologic sequestration in the southeast: U.S. Southern States Energy Board and Southern Company Kemper County Mississippi's ECO_2S project (number 15 on the map above). The ECO_2S project is a delineated and studied 30,000-acre area near the Kemper County energy facility.[327] The consortium, formed in 2016, has, so far, drilled four wells into the Tuscaloosa Group, Washita-Fredricksburg Interval, and Paluxy Formation, which, together, show great promise to store large

[327] David Riestenberg, *supra* note 279.

volumes of CO_2 in its thick, stacked Cretaceous-age sandstones which lie beneath a thick mudstone caprock. These low-cost ($2-4/tonne) highly porous and permeable saline reservoirs (e.g. 30 percent porosity and Darcy-class permeability in the Paluxy) may be able to accommodate large commercial CO_2 volumes and have potential to provide a regional storage hub for Mississippi and other Southeast states.

Another important CarbonSAFE project is the Integrated Mid-Continent Stacked Carbon Storage Hub.[328] When operational, the hub could provide the Midwest with an integrated midcontinent storage facility, which could serve 50 Mt or greater capture projects in the vicinity of Nebraska and pipeline it to central Kansas along a stacked storage corridor. The storage corridor is characterized as regionally continuous storage and caprock formations.

In sum, EPA, in the Proposal and supporting technical documents, acknowledges CarbonSAFE but fails to identify the available findings to date from the CarbonSAFE projects—initiated in 2016 after the final rule in 2015. The CarbonSAFE projects, building off results of the decade-long NETL RSCP program, have already begun to publish important findings, most importantly, the potential for a vast regional, and inexpensive sequestration hub at the ECO_2S project Kemper County Mississippi site, and the potential for a stacked storage hub in Kansas—demonstrating that large saline storage aquifer may already be, or will soon be readily available for sequestration in the Midwest and Southeast. The CarbonSAFE program will continue through 2025 to strengthen the body of knowledge and building confidence in the availability of large regional sequestration resources that could serve as CO_2 storage hubs accessible to distant projects by pipeline. That DOE and CarbonSAFE are continuing to study and refine their understanding of geologic sequestration does not render the currently available wealth of information insufficient for purposes of this rulemaking, as suggested in the Proposal.[329] Geologic sequestration, as described in the 2015 rulemaking record and supplemented here, is demonstrated and widely available.

b. Pipeline networks can transport captured CO_2.

Today's long-distance CO_2 pipelines can deliver captured CO_2 to storage hubs, and modeling studies demonstrate how pipeline networks can be built to transport captured CO_2 to distant sequestration sites. Pipeline networks will play an important role in providing storage opportunities for CO_2 from coal plants not located above or adjacent to a storage basin. Pipelines are a mature and safe CO_2 commercial transport method that have been proven by decades of use as evidenced by the 5,237 miles of CO_2 pipelines in the U.S. as of February 2019.[330] This total pipeline system, which spans many states and neighboring Canada, carries about 68 Mtpa of natural and anthropogenic CO_2 and has continued to grow to meet demand from the EOR industry.[331] At this time, about 20 percent of the CO_2 is from captured sources, and the remainder is naturally sourced CO_2. However, according to NETL in a 2015 report, EOR alone could absorb 400 Mt of CO_2 per year, 85 percent of which would be from captured sources.[332]

[328] Andrew Duguid, *supra* note 281.
[329] 83 Fed. Reg. at 65,442.
[330] Pipeline & Hazardous Materials Safety Admin., *supra* note 63.
[331] NETL, DOE, *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
[332] *Id.*

Still, in the Proposal EPA largely ignores the role of pipelines to connect distant sources and sinks, concluding that "…saline storage has not yet been demonstrated to be available, both from a geographical perspective as well as economically, at all locations."[333] But storage need not be demonstrated at *all* locations; new plants can utilize new and existing pipelines to connect to storage opportunities.

As EPA described in the record underlying the current rule, 5,195 miles of CO_2 pipeline network were operational in 2015, noting examples of Denbury and Kinder Morgan's high capacity interstate CO_2 pipelines.[334] EPA provided that the network has remained safe for decades, and transports millions of tons of supercritical CO_2 from diverse natural and captured sources to EOR projects in the Gulf Coast, Rocky Mountain, and Permian Basin. EPA concluded that "CO_2 pipelines are the most economical and efficient method of transporting large quantities of CO_2. CO_2 has been transported via pipelines in the U.S. for nearly 40 years. Over this time, the design, construction, operation, and safety requirements for CO_2 pipelines have been proven, and the U.S. CO_2 pipeline network has been safely used and expanded."[335]

Furthermore, in its 2015 rule, EPA disagreed with commenters who argued that the existing CO_2 network was inadequate and not available in the majority of the U.S., responding that "[t]he EPA does not agree. The CO_2 pipeline network in the U.S. has almost doubled in the past ten years in order to meet growing demands for CO_2 for EOR. CO_2 transport companies have recently proposed initiatives to expand the CO_2 pipeline network."[336]

And while some of those initiatives, such as the proposed Denbury Resources' Midwest pipeline, remain unbuilt, the accompanying studies support EPA's assessment of the feasibility of pipeline build-out as CO_2 supply and demand increase as a result of carbon capture.

The role of CO_2 pipelines in integrated CCS projects is demonstrated by two current U.S. anthropogenic CO_2 projects, each pipelining 1 Mtpa or more of CO_2 for use in EOR in the U.S. Gulf Coast. The first is NRG's Petra Nova Plant in Thompsons, Texas, which as discussed above, is America's first commercial-scale full-chain post-combustion capture project and demonstrates the ability to capture and transport CO_2 for geologic storage.[337] 1.4 Mtpa of supercritical CO_2 is delivered from Petra Nova to the West Ranch Field through a newly-constructed 12-inch diameter supercritical pipeline 82 miles to the south. The project is on track to deliver CO_2 to the EOR site for 20 years.[338] The project has been operating successfully for several years, starting January 2017 and reported capturing and transporting 1 Mt of CO_2 in the first ten months of operations[339] The plant is designed to capture the 1.4 Mtpa of CO_2 from a 240 Mwe slipstream from Unit 8 and transporting the 99 percent purity CO_2 to the Hilcorp West Ranch Field for EOR. A storage

[333] 83 Fed. Reg. at 65,442.
[334] *See* 80 Fed. Reg. at 64,581-82.
[335] *Id.* at 64,581.
[336] *Id.*
[337] NETL, DOE, *Recovery Act: W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project*, https://www.netl.doe.gov/research/coal/project-information/fe0003311 (last visited Mar. 12, 2019).
[338] EIA, *supra* note 102.
[339] *See* NRG Energy, Inc., *Carbon Capture and the Future of Coal Power*, https://www.nrg.com/case-studies/petra-nova.html (last visited Mar. 12, 2019).

monitoring plan for the project was designed by the Texas Bureau of Economic Geology. The second is Air Products' Project, which captures CO_2 from two existing steam methane reformers at the Valero Refinery in Port Arthur, Texas, and is connected by a 13-mile spur to Denbury's 320 mile Green Pipeline in 2013.[340] The captured CO_2 is delivered for injection into Denbury's Onshore EOR operations at Hastings Field in Houston.[341] Approximately 1 Mtpa of CO_2 or 90 percent is recovered and purified at the plant and transported by pipeline.[342] The project started full-scale operations in April 2013 and is still successfully operating today.

Numerous studies over the past decade have examined the potential for a nationwide network of pipelines for CO_2 transport. Different methods and considerations were used in each case to connect sources to suitable storage sites, with some using direct point-to-point routes, and others considering aggregating emission from multiple sources into a trunk line. The results of those analyses demonstrate the necessity for, and viability of, a network of U.S. CO_2 pipelines to transport large volumes of CO_2 necessary to meet climate objectives. In one of the most comprehensive studies NETL (2011) looked at the 388 large coal plants existing nearly a decade ago and found that 84 percent of them were within 25 miles of storage, 97 percent were within 100 miles of storage – 322 of the 323 GW examined were within 150 miles of storage.[343] NETL found that "both transport and storage requirements for retrofits at a significant number of sites have a good chance of being met.

The NETL report also details the expansions of the pipeline system that were planned at the time of the report and modeled EIA-NEMS analysis to investigate a range of pipeline expansion scenarios. A modeled 2030 case projected 56 new pipeline segments and 11,000 miles of new pipelines, primarily from electric power plants to EOR projects and saline storage sites, based on a tripling of carbon capture in the U.S, with 99 percent coming from electric utilities. Pipelines were built at an average cost of $562,000 per mile with $323 million per mile for interstate pipelines and $624 million per mile for intrastate pipelines. Additional NETL pipeline analysis published in 2015 found that if a CO_2 emissions cap was imposed of 40 percent of 2005 levels by 2030 and 80 percent by 2050, 15,194 miles (24,452 km) of pipeline would exist by 2040.[344]

A 2010 DOE/NETL study examined transportation from plants to storage basins estimated transport costs to be $3.65/tonne.

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340 John Palamara et al., *Air Products: Success in Advanced Separation and CO_2 Processing for EOR* (Dec. 12, 2013), http://www.co2conference.net/wp-content/uploads/2013/12/3-Palamara-AirProducts_CO2_Conference_Dec_2013_CO2EOR.pdf; *see also* Denbury Res. Inc., *Gulf Coast CO_2 Pipelines*, https://www.denbury.com/operations/gulf-coast-region/Pipelines/default.aspx (last visited Feb. 27, 2019).

341 *See* Denbury Res. Inc., *Naturally Occurring CO_2 Sources*, http://www.denbury.com/operations/gulf-coast-region/co2-sources-and-pipelines/default.aspx (last visited Feb. 27, 2019).

342 *Id.*

343 NETL, DOE, *Coal-Fired Power Plants in the United States: Examinations of the Costs of Retrofitting with CO_2 Capture Technology, Revision 3* (2011), https://www.netl.doe.gov/projects/files/FY11_CoalFiredPowerPlantsintheUSExamofCostsofRetrofitCO2CaptureTechRevision3_010111.pdf.

344 NETL, *supra* note 331.

Other studies demonstrating CO_2 pipeline feasibility include:

- A 2009 study modeled potential pipeline buildout scenarios for CO_2 pipelines.[345] The study showed that to limit the atmospheric CO_2 levels to 450 ppm and 550 ppm, 23,000 miles (37,014 km) or 11,000 miles (17,702 km) respectively would be needed – and could be built – by 2050. The study concluded that the need to increase the size of the existing dedicated CO_2 pipeline system should not be seen as a major obstacle for the commercial deployment of CCS technologies in the U.S.

- In 2017, the State CO_2-EOR Working Group illustrated the ability of five pipeline corridors (map below), at a cost of $15 billion, to transport CO_2 from areas of high industrial activity, including coal plants, to depleted oil fields for EOR.

Figure 9: 2017 Policy Study Illustration of Potential Pipeline Corridors

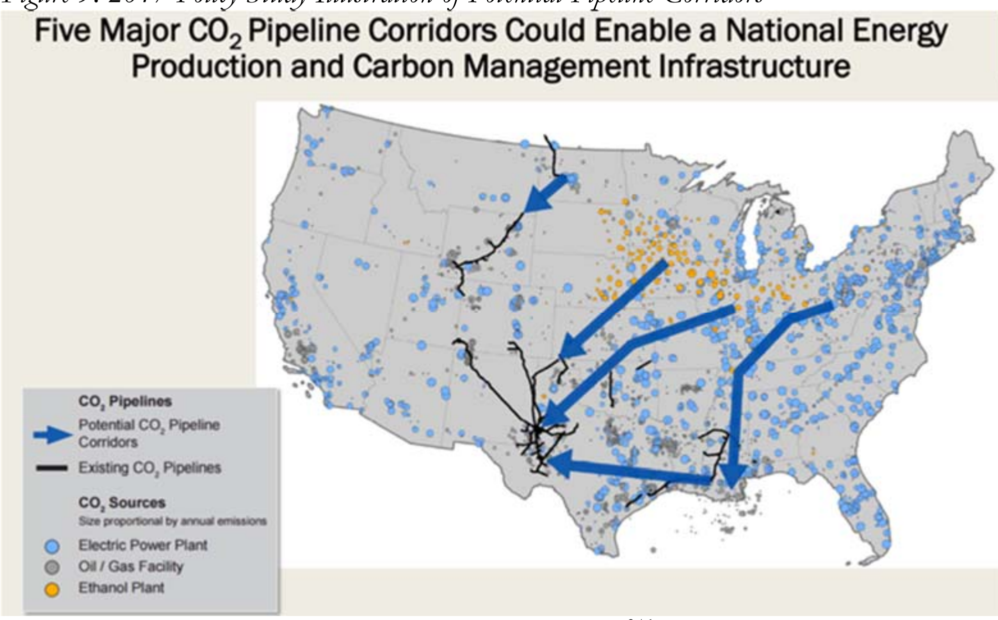

Image Source: State CO_2-EOR Deployment Work Group[346]

- Zelek, *et al.*, (2012) NEMS-CCUS model results found that captured emissions were stored, in general, within 100 miles of the source via direct pipelines.[347]

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345 J.J. Dooley et al., *Comparing Existing Pipeline Networks with the Potential Scale of Future U.S. CO_2 Pipeline Networks*, 1 ENERGY PROCEDIA 1595 (2009), https://www.sciencedirect.com/science/article/pii/S1876610209002100.

346 *See* State CO_2-EOR Deployment Work Group, *21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks* (2017), http://www.betterenergy.org/wp-content/uploads/2018/02/White_Paper_21st_Century_Infrastructure_CO2_Pipelines_0.pdf; State CO_2-EOR Deployment Work Group, *Infrastructure for Carbon Capture: Technology, Policy and Economics* (2017), https://www.naruc.org/default/assets/File/GPI%20NARUC%20webinar%20slides.pdf.

347 Charles A. Zelek et al., *NEMS-CCUS: A Model and Framework for Comprehensive Assessment of CCUS and Infrastructure* (2012), https://netl.doe.gov/projects/files/FY12_NEMSCCUSAModelandFrameworkforComprehensiveAssessmentofCCUSandInfrastructure_020712.pdf.

- A 2018 Princeton study demonstrates the feasibility of linking Midwest CO_2 sources by pipeline, proposing several pipeline corridors (*see* figure below) that could provide a capacity of 19-30 Mtpa linking low-cost CO_2 sources from ethanol refineries in the Midwest to dedicated geological storage resources in West Texas and the Permian Basin or Wyoming.[348]

Figure 10: Map of M*odeled* P*otential* C*arbon* D*ioxide* P*ipelines*

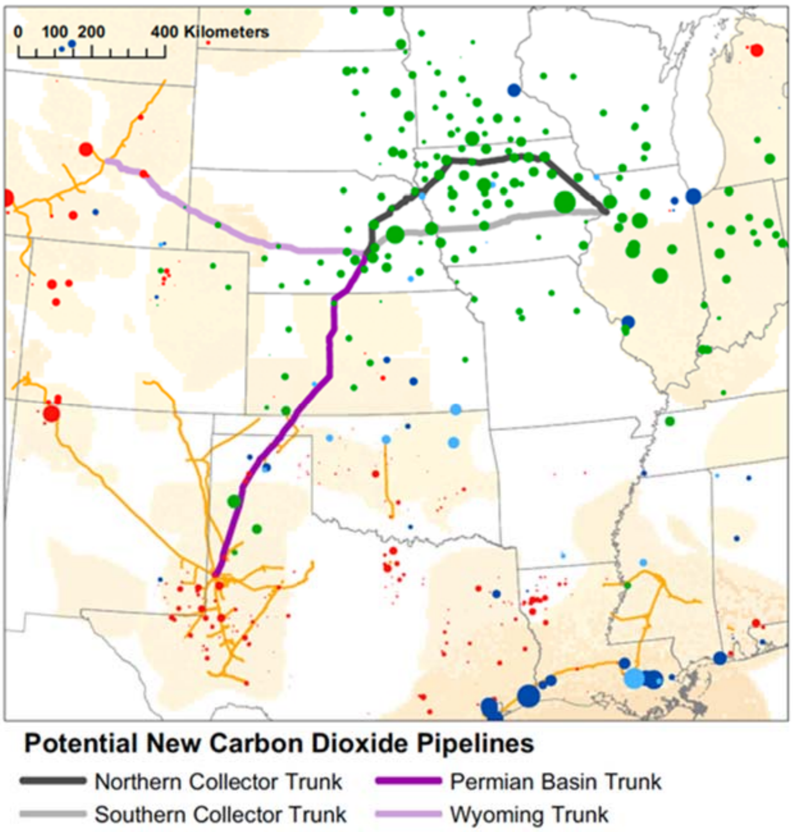

Image Source: Edwards & Celia (2018)

- A 2014 NETL publication describes DOE's transport cost model designed to estimate the price of CO_2 transported, broken out by region, covering all costs, including a return on investment on 12, 16 and 20-inch diameter pipelines.[349] The report also cites a variety of previous estimates of cost including, for example, Kinder Morgan's pipeline cost metrics, shown in the table below.

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[348] Ryan Edwards & Michael Celia, *Infrastructure to Enable Deployment of Carbon Capture, Utilization, and Storage in the United States*, 38 PROC. NAT'L ACAD. SCI. 115 (2018) (Attach. I).
[349] NETL, DOE, *FE/NETL CO_2 Transport Cost Model: Description and User's Manual* (2014), https://web.archive.org/web/20160101135722/https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/co2-transp-cost-model-desc-user-man-v1-2014-07-11.pdf.

Table 3: Kinder Morgan Pipeline Cost Metrics

Terrain	Capital Cost ($/inch-diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150'-200' depth)	$700,000

Source: NETL (2014)

The probable geographic locations for newly constructed power plants will be influenced by low-cost transport of coal to those sources. This means that new plants will likely be constructed at locations near mines (mine-mouth power plants), and locations of existing sources, or along rail lines where coal is commonly transported. The map below, although dated, provides a useful view of coal-fired EGUs in the year 2000 prior to widespread retirements. Because new plants are likely to be situated where coal is plentiful, sedimentary basins that contain coal will also be basins that have sedimentary sections that could store CO_2. In the unlikely chance that a new plant is built distant from coal resources, a recent CATF study, described below, suggests that locations, such as in the Appalachians, could access storage resources via pipeline. Elsewhere in these comments, we also argue that these basins are far better characterized than EPA has described in the Proposal, with substantial available subsurface data beyond that which EPA has cited in the 2015 NATCARB Atlas version V.

Figure 11: US Coal-Fired Power Plants Subject to the ACE Rule and Overlay on Oil and Gas Fields and Saline Storage Resources

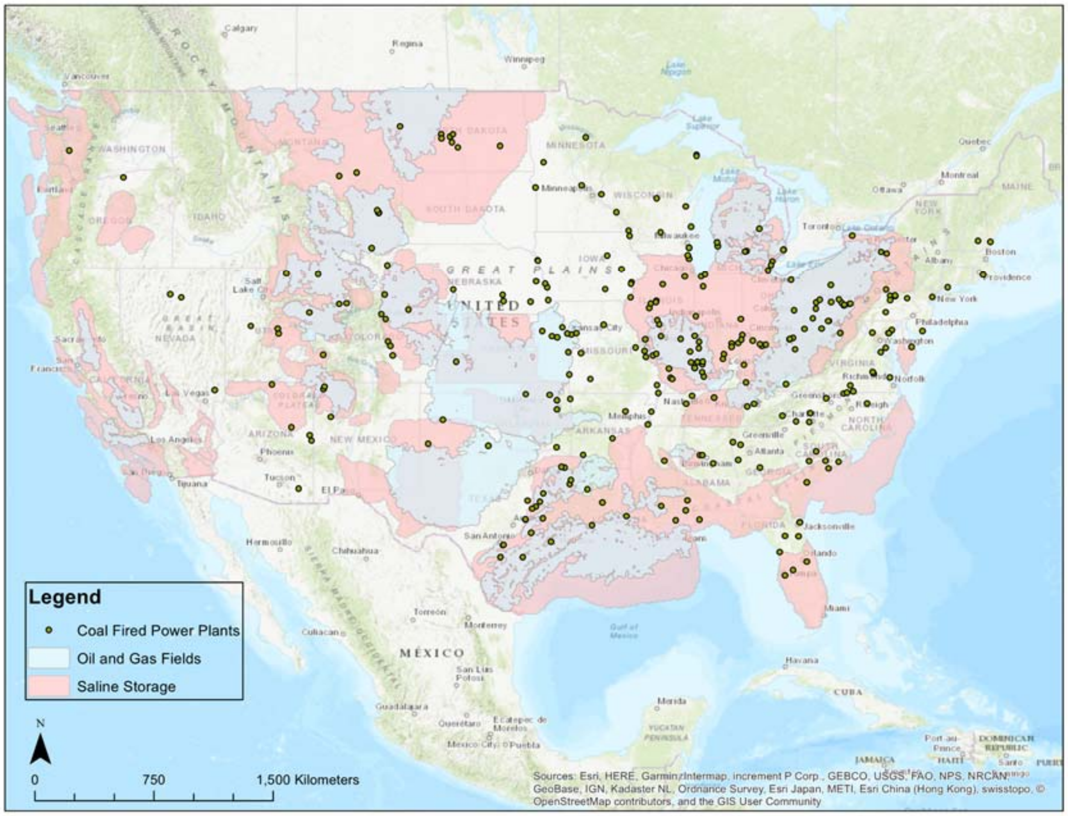

Image Source: Peter Tutton, University of Texas GCCC for CATF

For its 2015 rule, EPA analyzed saline and EOR-based sequestration capacity in the U.S. and existing sources and concluded that "…there is widespread potential for GS in the United States. If an area does not have a suitable GS site, EGUs can either transport CO_2 to GS sites via CO_2 pipelines or they may choose to locate their units closer to GS sites and provide electric power to customers through transmission lines." [350]

In 2018, Clean Air Task Force commissioned a study by the Texas Bureau of Economic Geology's GCCC, which built on the EPA's Geological Sequestration in the U.S. map to illustrate the availability of geologic storage for existing coal power plants. The study demonstrated that each of the existing sources - representing the most likely regions for any new or modified coal power plants - can be matched to a reasonable storage site, further supporting the previous determination that partial-CCS is the best system of emission reduction.

The University of Texas GCCC source-sink analysis commissioned by Clean Air Task Force had the objective to identify the closest geologic storage opportunities for each existing coal power plants. Results demonstrated that captured CO_2 from *every one* of the existing coal plants affected by the ACE rulemaking can be pipelined a reasonable distance to a storage basin in the U.S. The results,

[350] 80 Fed. Reg. at 64,581.

illustrated in the map below, show the applicable sources paired with storage locations. An estimate of the total distance required to link the emissions source to storage sites is included in tabular form as an appendix to our comments on the ACE Proposal.[351]

The source-sink analysis suggests that source-sink distances for coal plants are well within the range of existing U.S. pipelines identified in NETL's 2015 report.[352] The analysis found:

- 25 percent of plants are less than 50 km (31 miles) from a potential geologic storage basin.
- 50 percent the plants are within a distance of 12 km (8 miles) (median value).
- 95 percent of the plants are within 200 km (125 miles) or less from a geologic sink.
- Only 14 of the 286 plants exceed a 200 km (124 miles) distance, ranging from 201 km (125 miles) to 349 km (216 miles). Of those, only 5 plants exceed 300 km (186 miles).

For comparison, from the same report:

- The CO_2 pipeline from the commercially successful post-combustion capture at the Petra Nova power plant extends 82 miles south to the West Ranch Field.
- The CO_2 pipeline from Dakota gasification to Weyburn field is 329 km (204 miles) a distance at which only 3 plants subject to the rule exceed.
- In the West Texas Permian Basin, trunk lines range from 183 km (113 miles) to 810 km (502 miles).
- Distribution lines in the Permian range from 6 km (4 miles) to 23 km (14 miles).
- In the Rocky Mountains, CO_2 pipelines range from 48 km (30 miles) to 371 km. (230 miles).
- In the Gulf Coast pipelines range from 81 km (50 miles) to 550 km (314 miles).

Figure 12: Histogram displaying numbers of sources in 50 km (31 mi) increments from source to sink analysis. For example, the (0, 50) bins are all plants that are 0-50 km from a storage basin, of which there are 209 sources of 286 total sources (73%)

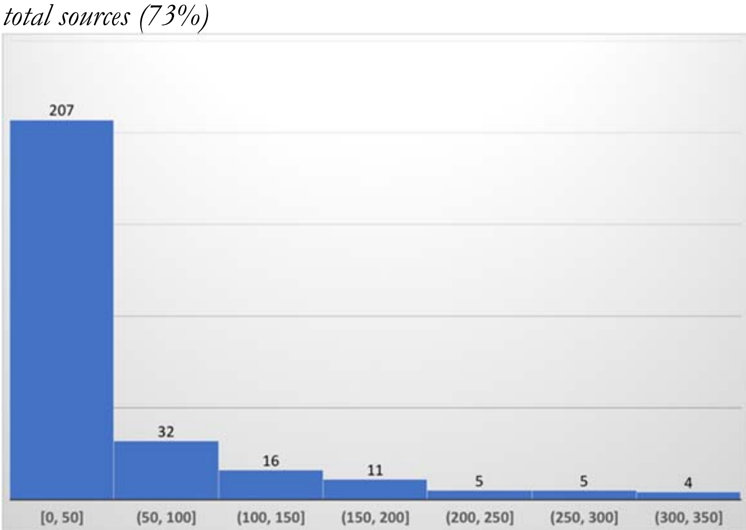

Image Source: P. Tutton for CATF analysis.

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[351] CATF & NRDC, Comments, *supra* note 57, at app. B, at 49-58 (Peter Tutton, *Matching 111d Affected Sources to Geologic Storage Locations in the U.S. for Carbon Capture and Sequestration* (2018)).
[352] NETL, *supra* note 331, at 4-14.

Figure 13: Map illustrating applicable coal-fired power plant sources capturing CO_2 (green dots) and paired geologic storage basins for ACE -applicable sources. Sedimentary basins with saline storage capacity are shaded tan and oil and gas fields in light blue. Where green source dots overlay storage basins, pipeline distances are too small to be shown in the continental-scale map.

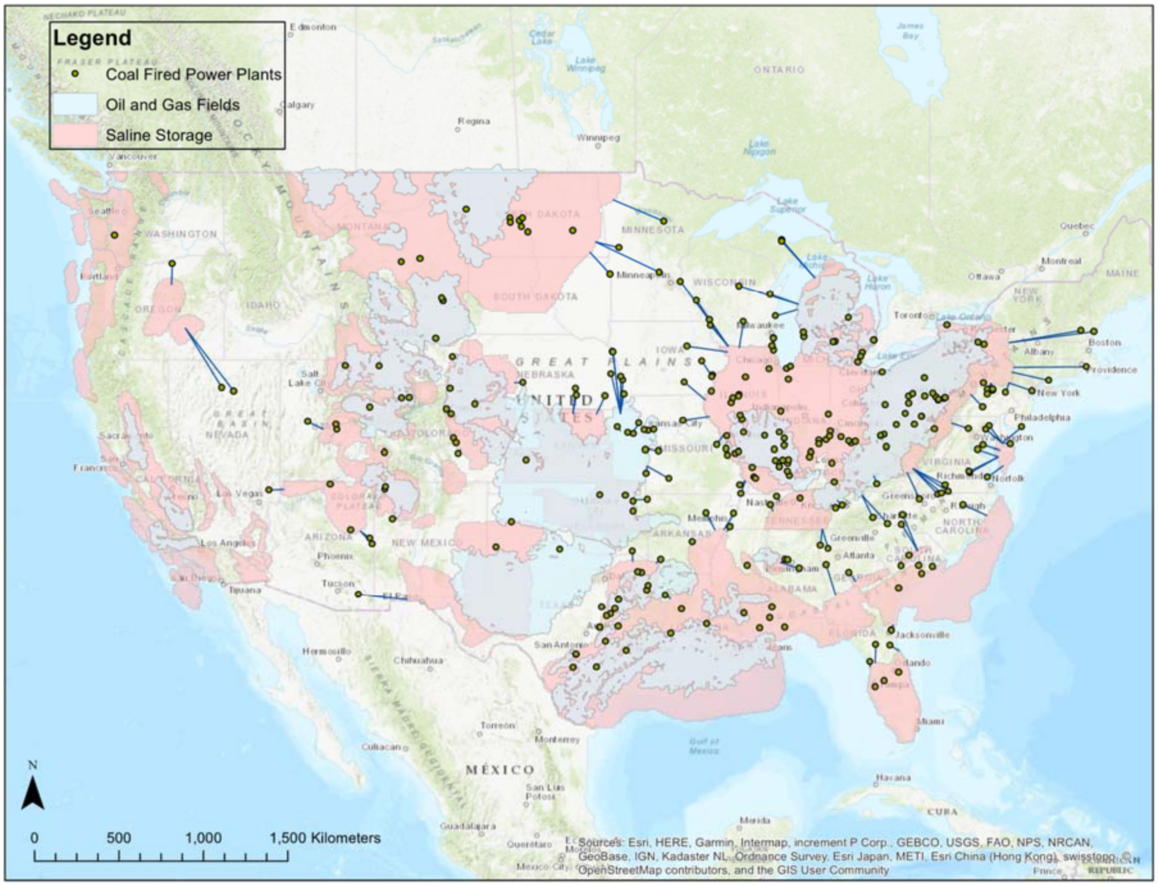

Image Source: Peter Tutton, University of Texas Austin, for Clean Air Task Force. See accompanying table in appendix.

In summary, EPA provides no substantive basis to overturn its 2015 conclusions documenting the robust, safe track record and low variable cost of CO_2 pipeline operations – despite the multiple factors contributing to the costs of their construction.[353] EPA's Proposal, in reversing its 2015 determination of the availability of sequestration, has overlooked the large body of data demonstrating the important role of supercritical CO_2 pipelines in delivering captured CO_2 to geographically distant projects, all of which was fully described by EPA in its 2015 rule and summarized above in these comments. This oversight ignores the realities of how power plants undertake CCS projects and in ignoring the availability of long-distance pipelines is arbitrary and capricious.

[353] EPA, Response to Comments, Standards for Fossil Fuel-Fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-107, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).

c. New power plants can be sited closer to storage sites and provide electricity to customers through transmission lines.

Coal-fired power plants have long found it more economical to locate near their coal supply than to have the coal shipped to the plant.[354] The plants then transmit their generation significant distances to customers. In 2015, EPA recognized this longstanding practice and determined that CCS plants could site closer to geologic sequestration opportunities and transmit electricity to customers.[355] EPA points to coal-fired power plants in Arizona and Utah which serve Los Angeles, California, as well as coal-fired power plants in Wyoming and Nevada, which serve Idaho and Oregon.[356]

Utilities continue to find large, expensive transmission projects to connect generation to customers economic. For example, in Wisconsin, the Badger Coulee project was put into service in late 2018 and consists of 180 miles of new 345 kV transmission line from Briggs Road Substation to Cardinal 345kV Substation.[357] The Badger Coulee project represents a significant investment of approximately $580 million that is providing access to lower-cost power and renewable energy, particularly imported higher-capacity wind energy.[358] Also in Wisconsin and Minnesota, the Hampton to Rochester to LaCrosse 345 kV Transmission Line Project improved access to generation in southeastern Minnesota.[359] As part of the CapX2020 transmission initiative, this project added about 155 miles of new 345 kV and 161 kV transmission line to the grid at a cost of $485 million and was fully energized in September 2016.[360]

The Minnesota-Iowa 345 kV Electric Transmission Project, also known as MISO's Multi-Value Project 3, involved the construction of approximately 145 miles of 345 kV line in Iowa and 70 miles of 345 kV line in Minnesota and was energized in 2018.[361] The project was estimated to cost $541 million and was part of the Multi-Value Project (MVP) portfolio intended to improve operations and efficiency of regional energy markets, provide access to low-cost generation, reduce energy waste, allow optimal use of wind energy resources, and provide optionality for future energy solutions.[362]

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354 80 Fed. Reg. at 64,583.

355 *Id.*; EPA, Technical Support Document: Geographic Availability, at 12-13, Doc. ID: EPA-HQ-OAR-2013-0495-11772 (July 31, 2015).

356 80 Fed. Reg. at 64,583.

357 Edison Electric Inst., *Transmission Projects: At A Glance*, at 20 (Dec. 2016), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

358 *Id.*

359 Ctr. for Rural Affairs, *Hampton-Rochester-La Crosse Transmission Line*, https://www.cfra.org/Hampton-Rochester-La%20Crosse-Transmission-Line (last visited Mar. 12, 2019).

360 CapX2020, *More Than 150 Miles of New Transmission Line Added to the Electric Grid* (Sept. 26, 2016), http://www.capx2020.com/lacrosse/CapX2020%20HRL%20project%20completed%20press%20release-r.pdf; Xcel Energy, *CapX2020 Transforms the Upper Midwest Grid*, 18 XTRA 1, at 8 (2017), https://www.xcelenergy.com/staticfiles/xe-responsive/Community/Xtra_Oct.1.2017.pdf.

361 Edison Electric Inst., *supra* note 357, at 80; *ITC Midwest Energizes New Electric Transmission Line in Southern Minnesota*, Albert Lea Tribune (Nov. 1, 2018), https://www.albertleatribune.com/2018/11/itc-midwest-energizes-new-electric-transmission-line-in-southern-minnesota/.

362 Edison Electric Inst., *supra* note 357, at 80.

In South Dakota, the Big Stone South-Brookings County project was energized in September 2017 as part of the MVP portfolio.[363] The project, which was the final line of the 800-mile CapX2020 project, consisted of 70 miles of 345 kV transmission line at a cost of approximately $140 million.[364] At least eight wind projects and a natural gas facility have already requested to interconnect to the line and substation.[365]

In California, the Tehachapi Renewable Transmission Project was built primarily to assist the development of renewable energy generation projects in remote areas of eastern Kern County, California.[366] The project was complete and energized in December 2016 and consisted of 11 segments totaling 250 miles of new and upgraded transmission lines and substations.[367] The Tehachapi Renewable Transmission Project required an estimated investment of approximately $3.2 billion and supports interconnection of up to 4,500 MWs of generation, most of which is expected to be renewable resources.[368]

It is unsurprising that gas-fired and renewable energy sources are tapping into these new transmission projects as they are the primary choice for new generation, but transmission lines and expansion projects are equally available to new coal-fired projects. The Proposal arbitrarily ignores its previous record,[369] and erases the more than 600,000 circuit miles of alternating current transmission lines crisscrossing the country connecting the over 8,000 generating units to its customers.[370]

3. There are several policy determinations or logistical considerations that would limit the location of a new coal-fired power plant.

As described above, EPA need only ensure that the standard is achievable for conditions that are likely to recur.[371] While the current standard is achievable everywhere, there are many factors that would prevent a coal-fired power plant from being built in many areas of the country. In 2015, EPA cataloged many of these reasons and the Proposal must recognize and update this work. For example, there are areas of the country that have such low population density that there is no demand for additional electricity. Nonattainment status for national ambient air quality standards precludes new highly-polluting sources from being built in many areas. Many states already have laws on the books that would not allow, or would significantly restrict, new uncontrolled coal-fired power plants to be built regardless of this standard[372] – states including California, Washington,

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[363] CapX2020, *Big Stone South-Brookings County 345 kV Project*, http://capx2020.com/bss/index.html (last visited Mar. 13, 2019).
[364] CapX2020, *Big Stone South-Brookings County 345 kV Transmission Line: Project Update* (Sept. 15, 2017), http://capx2020.com/bss/BigStone-factsheet-Sept-2017.pdf; Xcel Energy, *supra* note 360, at 8.
[365] Xcel Energy, *supra* note 360, at 8.
[366] Edison Electric Inst., *supra* note 353, at 122.
[367] S. Cal. Edison, *Tehachapi Renewable Transmission Project*, https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11 (last visited March 13, 2019).
[368] Edison Electric Inst., *supra* note 353, at 123.
[369] *Fox Television Stations*, 556 U.S. at 537 (Kennedy, J., concurring).
[370] Theodore U. Marston, *The US Electric Power System Infrastructure and Its Vulnerabilities*, 48 THE BRIDGE: JOURNAL OF THE NATIONAL ACADEMY OF ENGINEERING 31 (Summer 2018), https://www.nae.edu/File.aspx?id=183084.
[371] *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46.
[372] *See generally* Ctr. for Climate and Energy Solutions, *State Climate Policy Maps*, https://www.c2es.org/content/state-climate-policy/ (last visited Mar. 13, 2019).

Oregon, New York, Montana, and Illinois.[373] States are also part of regional partnerships, which limit the ability to build new highly-polluting emission sources – partnerships such as the Regional Greenhouse Gas Initiative and the U.S. Climate Alliance.[374]

"In the absence of federal action, U.S. states have stepped up and accelerated meaningful climate action," said Craig Ebert, President of the Climate Action Reserve. "States have enacted sensible, equitable, and economically beneficial climate policies, including raising ambitious climate targets, putting a price on carbon…"[375] State policies initiated since the rule was finalized expand the area of the country inhospitable to new uncontrolled coal-fired power plants.[376] For example, on October 29, 2018, the Virginia State Air Pollution Control Board proposed to tighten limits CO_2 pollution from fossil fuel-fired power plants (30 percent reduction by 2030) and join the Regional Greenhouse Gas Initiative.[377] In North Carolina, the Governor issued an executive order last year seeking to reduce greenhouse gas emissions 40 percent from 2005 levels by 2025.[378] New Jersey set forth an economic plan calling for 100 percent clean energy by 2050 and 50 percent by 2030[379] and a new state law in Illinois requires 25 percent of the state's electricity to be generated by clean sources by 2025.[380]

The Proposal arbitrarily fails to acknowledge that there are significant areas in the country where a new coal plant will not, or cannot, be built. The Agency must update its 2015 analysis to determine where a new coal plant could be built in order to engage in reasoned decision-making.

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373 80 Fed. Reg. at 64,582; EPA, Technical Support Document: Literature Survey of Carbon Capture Technology, at 35, Doc. ID: EPA-HQ-OAR-2013-0495-11773 (July 10, 2015).

374 *See generally* Elizabeth Shogren, *As Trump Retreats, States Are Joining Forces on Climate Action*, YALEENVIRONMENT360 (Oct. 9, 2017), https://e360.yale.edu/features/as-trump-retreats-states-are-stepping-up-on-climate-action.

375 Climate Action Reserve, *U.S. States Take Leadership Role in Advancing Climate Action at COP24* (Dec. 12, 2018), http://www.climateactionreserve.org/blog/2018/12/12/u-s-states-take-leadership-role-in-advancing-climate-action-at-cop24/.

376 *See, e.g.*, EIA, *Annual Energy Outlook 2016 with Projections to 2040*, at LR-2 (Aug. 2016), https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf ("addition of a new RPS policy in Vermont and expanded RPS targets in California and Hawaii"); EIA, *Annual Energy Outlook 2017 with Projections to 2050*, at 32 (Jan. 5, 2017), https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf ("California state law SB-32, which was passed in 2016, requires statewide greenhouse gas emissions to be 40% below the 1990 level by 2030."); EIA, *Annual Energy Outlook 2018 with Projections to 2050*, at 35 (Feb. 6, 2018), https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf ("A number of current state and regional policies—including the Illinois Future Energy Jobs Act, the New York Clean Energy Standard, the Maryland Clean Energy Jobs Act, and the Regional Greenhouse Gas Initiative—affect the projected electric generation mix"); EIA, *Annual Energy Outlook 2019 with Projections to 2050*, at 40 (Jan. 24, 2019), https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf ("A number of new state and regional policies were enacted in the past year. These policies included California's requirement for 100% clean energy generation by 2045 and New Jersey's and Massachusetts's increased renewable portfolio standard (RPS) requirements that renewables contribute 50% and 35% of generation, respectively, by 2030.").

377 Va. Dept. of Envt'l Quality, *Proposed Carbon Emissions Re-Regulation Moves Forward*, DEQ NEWS RELEASES (Oct. 29, 2018), https://www.deq.virginia.gov/ConnectWithDEQ/NewsReleases.aspx.

378 Sarah Willets, *NC Governor Signs "Unprecedented" Executive Order to Reduce Greenhouse Gas Emissions*, INDY WEEK (Oct. 29, 2018), https://indyweek.com/news/northcarolina/nc-governor-si/.

379 Gov. Philip D. Murphy, *The State of Innovation: Building a Stronger and Fairer Economy in New Jersey* (Oct. 2018), https://www.njeda.com/pdfs/StrongerAndFairerNewJerseyEconomyReport.aspx.

380 Dan Gearino, *Can Illinois Handle a 2000% Jump in Solar Capacity? We're About to Find Out*, INSIDECLIMATE NEWS (Oct. 30, 2018), https://insideclimatenews.org/news/30102018/illinois-community-solar-renewable-energy-law-job-training-project-lottery-selection-midwest.

C. The cost of partial-CCS was reasonable in 2015 under conservative assumptions and continues to decline.

In 2015, EPA determined that the costs of CCS are reasonable under a range of market conditions and other factors.[381] Courts hold that costs are reasonable where "[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the…standards,"[382] and are not "exorbitant."[383] As EPA recognizes in the Proposal, courts have historically upheld "standards that entailed significant costs."[384] The 1977 Clean Air Act Amendments were "intended to create incentives for improved technology, which could achieve greater or equivalent emission reduction at equivalent or lower cost, energy demand, and environmental impacts."[385]

As EPA explained in the companion ACE 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.[386] EPA may also consider revenues generated as a result of the application of pollution control measures in assessing the costs of a system of emission reduction.[387] As EPA recognized in 2015, the availability of subsidies does not undermine the case for particular pollution control and is "not unusual. Government subsidies in the form of tax benefits, loan guarantees, low-cost leases, or direct expenditures have supported the development of fossil fuel as well as nuclear, geothermal, wind, and solar energy development."[388] Additionally, as section 111(b) is forward-looking and aimed at the next new plant, the Agency must take into account that costs follow a typical declining trajectory in response to regulation as more projects are developed and built.[389]

As EPA recognizes, the costs of CCS on a coal-fired power already come at a premium because the underlying coal-fired power plant is not the most economical choice for new baseload power generation.[390] Natural gas-fired power plants are less expensive and less polluting, on an individual basis at the stack, than coal-fired power plants and are the overwhelming choice for new builds. "[H]igher costs can be viewed as reasonable when costs are not a paramount factor in new coal capacity decision."[391]

If a company does decide to build a highly-polluting, coal-fired power plant, it is Congress' view that "the costs of applying best practicable control technology be considered by the owner of a large new

381 2015 RIA, at ch. 5.
382 *Portland Cement*, 486 F.2d at 508; *see also* 83 Fed. Reg. at 65,433 (quoting same).
383 *Lignite Energy Council*, 198 F.3d at 933; *see also* 83 Fed. Reg. at 65,433 (quoting same).
384 83 Fed. Reg. at 65,533 (citing *Essex Chemical Corp.*, 486 F.2d at 440); *Portland Cement Ass'n*, 486 F.2d at 387-88; *Sierra Club,* 657 F.2d at 313 (upholding standard imposing controls on sulfur dioxide (SO_2) emissions from coal-fired power plants when the "cost of the new controls . . . is substantial")).
385 H.R. Rep. No. 95-294, at 186 (1977).
386 83 Fed. Reg. at 44,759.
387 *See New York v. Reilly*, 969 F.2d 1147, 1150-52 (D.C. Cir. 1992).
388 EPA, Response to Comments, Standards for Fossil Fuel-Fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-75, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).
389 *Portland Cement Ass'n*, 486 F.2d at 391.
390 80 Fed. Reg. at 64,559; 83 Fed. Reg. at 65,427; 2018 EIA at 2-2 ("it is highly unlikely that over the analysis period there will be a sufficient increase in relative fuel prices (e.g., natural gas prices relative to coal) to make a typical new coal-fired EGU cost-competitive with available substitutes such as NGCC").
391 80 Fed. Reg. at 64,559.

source of pollution as a normal and proper expense of doing business."[392] But instead, the Proposal's amended LCOE "does not account for any of the potential benefits of reduced criteria and GHG emissions due to the use of CCS."[393] In 2015, EPA found that an uncontrolled coal plant imposes up to $91 of health impacts on the public for every MWh generated as compared to a natural gas plant.[394] EPA concluded that the cost range of a new gas-fired power plant was $52-86/MWh.[395] Adding $91/MWh to this range implies that the actual cost, including health impacts, of a new coal plant without CCS ranges between $143-177/MWh. This cost is higher than adding 90 percent capture to the coal plant, a capture level that nearly eliminates the air-related health impacts.[396] Agencies "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[397] The failure of the EPA to account for the costs of air pollution is arbitrary and capricious, especially because at the same time it monetizes the private cost savings to individual operators.[398] Without accounting for the costs of pollution, EPA cannot properly consider the appropriateness of either partial capture or full-capture options in establishing emission standards for new coal plants.

In 2015, EPA took an overly conservative approach to analyzing the costs of CCS, which were based on the highest value in the projected range with high-risk financing structures[399] and did not include EOR revenue, 45Q or 48A tax credits, or the expected cost declines over the regulatory period.[400] EPA conceded that "actual costs will be less than those presented."[401] However, even with this unrealistically high assessment of costs, EPA found that the cost of partial-CCS was reasonable. Now, the Proposal fails to take these factors into account and fails to take into account the cost declines that have occurred over the past four years – relying on 2015 cost estimates and failing to confirm that they are still accurate.

Congress expected section 111 to control sources "to the maximum practicable degree."[402] Given the aims and purposes of the Clean Air Act and section 111, the Agency should "err on the side of overprotection."[403] Taking an unrealistically conservative approach to costs and then failing to choose a more protective system of emission reduction based on that unreasonable assessment, renders this Proposal unlawful.[404]

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392 H.R. Rep. 95-294, at 184 (1977), *reprinted in* 1977 U.S.C.C.A.N. 1077, 1262; *see also* 83 Fed. Reg. at 65,433 (quoting same).
393 83 Fed. Reg. at 65,440.
394 2015 RIA, 5-7 tbl. 5-2.
395 83 Fed. Reg. at 65,437 tbl. 4.
396 EPA relies on NETL studies to assess the cost of CCS. An SCPC plant with 90% capture is estimated to cost $142.8/MWh. *See* NETL, DOE, DOE/NETL-2015/1720, *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants*, at 18 ex. A-3 (June 22, 2015), https://www.netl.doe.gov/projects/files/SupplementSensitivitytoCO2CaptureRateinCoalFiredPowerPlants_062215.pdf.
397 *Ctr. For Biological Diversity v. NHTSA*, 538 F.3d 1172, 1198 (9th Cir. 2008).
398 2018 EIA, at 2-4 tbl. 2-1.
399 80 Fed. Reg. at 64,563 (the LCOE would have been $94/MWh using conventional financing assumptions).
400 *Id.*
401 *Id.* at 64,564.
402 Summary of the Provisions of the Conference Agreement on Clean Air Act Amendments of 1970, 116 Cong. Rec. 42,384 (Dec. 8, 1970).
403 *NRDC*, 902 F.2d at 972; *see also State Farm*, 463 U.S. at 55 ("Congress intended safety to be the preeminent factor under [the Act] . . . .").
404 In the Proposal here, however, EPA argues that partial capture is too costly. EPA amends the LCOE for bituminous SCPC plants with 16% capture from $96.2/MWh to $105.4/MWh and for sub-bituminous SCPC plants with 26%

As we describe below, costs were reasonable in 2015, are more reasonable now, and will continue to decline significantly over the regulatory period – which is the relevant time period, for this forward-looking section of the Act.

1. The current standard imposes limited, if any, costs.

The current 1,400 lbs. CO_2/MWh standard imposes no costs on nationwide electricity prices, operating plants demonstrate that the costs of CCS are not exorbitant, and plants have the even lower-cost option of co-firing with natural gas to meet the standard.

In 2015, EPA determined that no uncontrolled coal-fired power plants would be built in the coming decade due to low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy.[405] Therefore, the impact on the source category as a whole would be negligible and certainly not more than "the [electric] industry can bear and survive."[406] The trends underpinning this analysis have continued and EPA's conclusion that this rulemaking will have minimal to no impact on nationwide electricity costs remains unchanged. Clearly, the *electric* industry – the relevant industry – can withstand the imposition of a 1,400 lbs. CO_2/MWh standard, as it has over the past four years.

However, if a plant owner decides to build a new coal-fired power plant for reasons other than economics, it is clear that plants can accommodate the costs of installing CCS because they have.[407] Two coal-fired power plants in North America have installed CCS, at levels higher than required by the standard, and are successfully operating today. Therefore, on a plant level, the costs are also reasonable.

Moreover, it is the *standard* that a plant must meet. The current regulation does not require a plant to install CCS. A plant can co-fire with 40 percent natural gas at a very low cost or build an IGCC to meet the standard.

2. EPA's reliance on outdated levelized cost of electricity figures for CCS is unreasonable.

In 2015, EPA relied on the peer reviewed DOE/NETL "Cost and Performance Studies" released in June 2015 for the capital costs and LCOE for partial-CCS.[408] The NETL studies "include up-to-date cost and performance information from recent vendor quotes and implementation of the Shell Cansolv post-combustion capture process – the process that is currently being utilized at the Boundary Dam Unit 3 facility."[409] These costs represented the next commercial offering and include

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capture from $109/MWh to $122.8/MWh. These increases, 10%, and 13% respectively, are small. Furthermore, these amended LCOEs still fall within the range estimated for partial capture by EPA in 2015. Even without further adjustment, the amended values for LCOE developed by EPA in this Proposal are acceptable.

405 2015 RIA at 1-4.

406 80 Fed. Reg. at 64,564 (citing *Portland Cement Ass'n*, 513 F.2d at 508).

407 *Id*. at 64,558.

408 *Id*. at 64,560-61.

409 *Id*.

process contingencies.[410] EPA then reviewed public pronouncements, as well as recently-published government, industry and academic techno-economic studies estimating the LCOE for CCS.[411] The Agency found that these independent studies were reasonably consistent with the NETL studies.[412] Finally, EPA reached out to vendors of CCS technology and plant owners and received additional information that corroborated NETL's LCOE for CCS.[413] EPA determined that the costs were reasonable even under very conservative assumptions.

In the current Proposal, EPA is reversing course, in part, due to "high costs."[414] However, EPA is relying on the same four year old NETL study reflecting Boundary Dam technology, which has been exceeded by Petra Nova's design, described above,[415] and has failed to review available literature or engage with company owners or vendors to update the costs. EPA failed to consider the benefits associated with the Petra Nova approach that separately supplies steam/electricity. In a low-gas price environment, this approach has important economic advantages. As a result, the outdated costs EPA relies on overstate the economic impacts of CCS.

Similarly, EPA must reach out to pipeline and storage vendors and operators and review recent literature to update the costs associated with CCS transportation and storage.

EPA's reliance on outdated cost data is unreasonable when significant, relevant information is available or could be obtained by reviewing recent cost studies and reaching out to vendors and plant owners. Again, EPA is an expert agency with a duty to perform a fulsome investigation to obtain the latest available information. Simply stating that it "is not aware of any more recent, detailed, or transparent costing analysis" is unreasonable.[416] While costs were reasonable in 2015, the failure to update the previous record renders this Proposal arbitrary and capricious. If EPA had updated the record, it would see that costs have declined since and are certainly not "exorbitant."

3. **EPA determined that CCS costs were reasonable even under very conservative assumptions.**

   a. CCS costs are declining.

As EPA recognized in 2015, "[s]ignificant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology."[417] 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 best system of emission reduction for new fossil fuel-fired power plants.[418] 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

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410 2015 RIA at 4-22 n.40.
411 *See generally* 80 Fed. Reg. at 64,567-68.
412 *Id.*
413 *Id.* at 64,568-69 (discussing outreach to Alstom, Summit, DOE and others).
414 *Id.* at 65,426.
415 Hari C. Mantripragada et al., *supra* note 109.
416 83 Fed. Reg. at 65,437.
417 80 Fed. Reg. at 64,566.
418 *Id.* at 64,756.

is deployed more."[419] It is these future costs that are relevant for section 111(b) rulemaking – it is a forward-looking statute[420] and all evidence before the Agency demonstrates that CCS costs are declining.

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, transformational R&D leads to deep cost reductions and higher performance relative to incremental R&D.[421]

In 2015, EPA explained that the costs for first-of-a-kind projects are not reasonably predictive of the costs for the next new plants.[422] This expectation has borne out. Petra Nova Parish Holdings 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.[423] 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 and demonstrate expected cost declines.

Petra Nova believes that the next CCS retrofit based on their approach will be at least 20 percent cheaper due to their experience with this project.[424] Approximately half of the savings come from eliminating "overkill" from the design that proved unnecessary based on the experience of Petra Nova. 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.[425] Based on these cost reductions, Petra Nova estimates the cost of capture from the second project based on their learnings to be about $2.5/MCF or around $47/tonne.[426] As detailed below, a recent study by MHI, the capture technology vendor for Petra Nova, confirms that the cost of the next project using their technology will be 30 percent less than MHI's conventional design.[427]

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419 Denial of Reconsideration, at App. 3 – Non-BSER CPP Flexibilities, at 5 (Jan. 2017), https://19january2017snapshot.epa.gov/sites/production/files/2017-01/documents/cpp_rd_appendix_3_-_nonbser_cpp_flexibilities.pdf (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) (Attach B), and Br. for *Amicus Curiae* Technology Innovation Experts, Doc. No. 1652263, *North Dakota v. EPA,* No. 15-1381 (D.C. Cir. Dec. 21, 2016) (Attach J)).
420 *Sierra Club*, 657 F.2d at 331 (citing legislative history).
421 CATF & NRDC, Comments, *supra* note 57, at Attach. F (Shayegh et al., *Evaluating Relative Benefits of Different Types of R & D for Clean Energy Technologies*, 107 ENERGY POLICY 532 (2017)).
422 80 Fed. Reg. at 64,570-71.
423 Petra Nova Parish Holdings LLC, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project: Final Public Design Report* (Feb. 17, 2017), https://www.osti.gov/servlets/purl/1344080.
424 David Greeson & 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.
425 Personal Communication, David Greeson to CATF (Dec. 13, 2017); *see also* Timothy Gardner, *Burying Carbon Emissions Gets Boost in U.S. Budget Deal*, REUTERS (Feb. 9, 2018), https://www.reuters.com/article/us-usa-carbon-credit/burying-carbon-emissions-gets-boost-in-u-s-budget-deal-idUSKBN1FT2UT.
426 CATF & NRDC, Comments, *supra* note 57, at Attach. D (David Greeson, *Petra Nova Capture Project*, GHGT-14 (Oct. 2018)).
427 Hiroshi Tanaka et al., *supra* note 106.

EPA's record also does not contain any reference to reports prepared by International Knowledge Centre on 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 Unit 3 CCS retrofit. The Centre's most recent report shows projected cost reductions at Shand of 67 percent compared to the Boundary Dam project.[428] 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."[429] The report estimates that the projected cost of capture is $45/tonne (U.S. dollars). Furthermore, the Shand feasibility design incorporates engineering elements that allow the plant to capture 96 percent of the CO_2 emissions when the capacity factor of the plant decreases to 63 percent follow load.[430] This benefit adds to the value of backing-up intermittent renewables with coal-CCS because it is much less carbon-intensive than gas-fired back-up of renewables.[431] The Shand Study notes that the use of hybrid cooling means that the plant's water consumption will not increase over the current plant's water allotment.[432]

These cost declines are only the beginning, however. The figure below depicts current DOE program goals for carbon capture innovation.

Figure 14: DOE Carbon Capture Program Goals

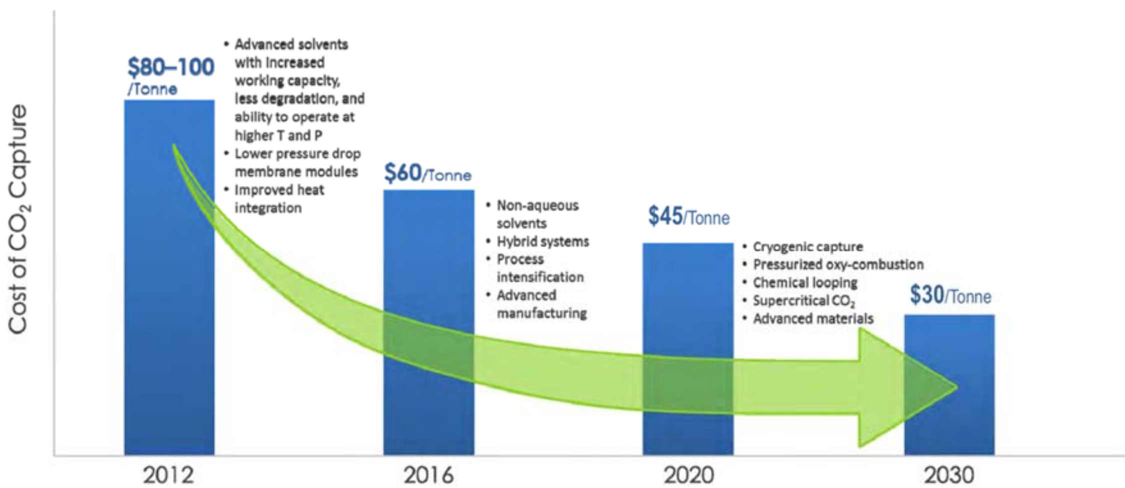

Image Source: DOE Office of Fossil Energy[433]

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428 CATF & NRDC, Comments, *supra* note 57, at Attach. C (Corwyn Bruce et al., *Post-combustion CO_2 Capture Retrofit of SaskPower's Shand Power Station: Capital and Operating Cost Reduction of a 2nd Generation Capture Facility*, GHGT-14 (Oct. 2018)).
429 *Id.* at 9.
430 Int'l CCS Knowledge Ctr., *supra* note 112, at 7.
431 *Id.*
432 Int'l CCS Knowledge Ctr., *Summary for Decision Makers on Second Generation CCS: Based on the Shand CCS Feasibility Study*, at 12 (Nov. 2018), https://ccsknowledge.com/pub/documents/publications/Summary%20for%20Decision%20Makers%20on%20Second%20Generation.pdf.
433 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.

The CO_2 capture cost of $45-47/tonne for the next plants building on the experiences at Petra Nova and Boundary Dam are consistent with DOE's CCS program goals. DOE's program seeks a $45/tonne capture cost for CCS by 2020. To support this goal, DOE recently released a Notice of Intent for a Funding Announcement Opportunity, to be formally issued in the second quarter of 2019.[434] The funding will support completion of at least two FEED studies for CCS on coal and natural gas power plants.[435] Applicants will form multi-disciplinary teams including, in addition to host site plant owners and operators, "vendors/technology developers; engineering, procurement and construction firms; original equipment manufacturers."[436] This is in addition to DOE/NETL's Carbon Capture program consisting of 47 active and 44 completed CO_2 capture technology R&D projects.[437]

The recent expansion of the 45Q tax credit, discussed *infra*, is likely to have a profound impact on attaining the $30/tonne goal too. Rubin et al., estimate the learning curve for CCS on coal plants.[438] The learning rates, defined as the fractional reduction in costs for each doubling of cumulative capacity, was from 1.1-9.9 percent for coal plants with CCS and 2-7 percent for natural gas with CCS.[439]

NRDC's most conservative modeling, discussed in Part III.C.3.c. below, showed 8.2 GW of future CCS builds by 2030. We estimate that the "learning-by-doing" achieved through these additional projects could reduce costs by up to 27 percent by 2030: assuming the level of near-term CCS deployment in NRDC's no carbon policy case, a 9.9 percent learning rate would reduce capture costs from $56/tonne to $40/tonne; under more realistic starting cost assumptions, capture costs could drop to $33-34/tonne by 2030.

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 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. Net Power is testing a high pressure, oxygen-fired, natural gas-fired power plant in Texas and expects testing to be complete in early 2019.[440] "At that time, Net Power expects to have the data necessary to commence detailed engineering of 300MWe commercial-scale plants with major power, oil and gas, and industrial customers around the world."[441] The operating conditions of the plant produce an inherently pure stream of CO_2 which is

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[434] Office of Fossil Energy, DOE, *DOE Issues Notice of Intent for Funding Opportunity for Front-End Engineering and Design Studies for Commercial-Scale Carbon Capture Systems* (Jan. 16, 2019), https://www.energy.gov/fe/articles/doe-issues-notice-intent-funding-opportunity-front-end-engineering-and-design-studies.
[435] *Id.*
[436] *Id.*
[437] NETL, DOE, *DOE/NETL Capture Program R&D: Compendium of Carbon Capture Technology* (Apr. 2018), https://www.netl.doe.gov/sites/default/files/netl-file/Carbon-Capture-Technology-Compendium-2018.pdf.
[438] Rubin et al., *A review of learning rates for electricity supply technologies*, 86 ENERGY POL'Y 198 (2015), https://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Rubin_et_al_Areviewoflearningrates_EnergyPolicy2015.pdf.
[439] *Id.* at 201 tbl. 1.
[440] Net Power, *NET Power and Oxy Low Carbon Ventures Announce Investment Agreement to Advance Innovative Low-Carbon Technology* (Nov. 8, 2018), https://www.prnewswire.com/news-releases/net-power-and-oxy-low-carbon-ventures-announce-investment-agreement-to-advance-innovative-low-carbon-technology-300746197.html.
[441] *Id.*

already at sufficient pressure for injection and storage. 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 natural gas combined cycle plant. Without the 45Q incentives, the costs of electricity of their plant and an uncontrolled natural gas-fired power plant would be about the same.[442] After the technology is demonstrated on natural gas, the owners of this technology plan to adapt it to be fueled by coal instead of gas. They project capital costs and LCOE that are lower than an uncontrolled SCPC or an uncontrolled IGCC and LCOE and near "emissions-free" operation.[443]

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 lower costs.[444]

Figure 15: Stages of Technological Change and Their Interactions

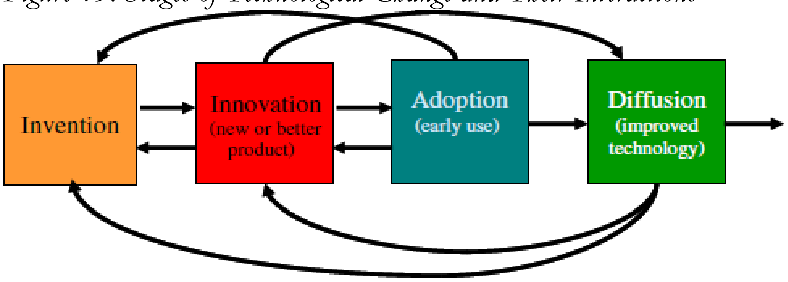

Image Source: Rubin et al. (2012)

Figure 16: Typical Cost Trend for a New Technology

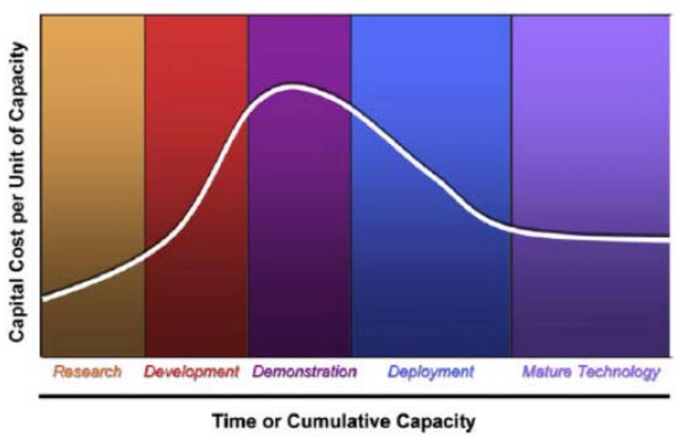

Image Source: Rubin et al. (2012)

442 Bill Brown, *Demonstration and Commercialization of Net Power and Beyond*, GHGT-14 (Oct. 2018) (photos of slide available on file with CATF).
443 Xijia Lu, *Flexible Integration of the sCO2 Allam Cycle with Coal Gasification for Low-Cost, Emission-Free Electricity Generation* (Oct. 28, 2014), https://www.globalsyngas.org/uploads/eventLibrary/2014_11.2_8_Rivers_Xijia_Lu.pdf.
444 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.

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."[445] 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.[446] The vendors were able to cut the capital costs of scrubbers in half over twenty years.[447] Further, initial reliability problems and low SO_2 pollution removal efficiencies were improved dramatically over a very short period of time as spurred by government actions.[448] Experts have shown that regulations consistently lead to spikes in patent filings related to the relevant pollution controls.[449] EPA found that "regulatory stringency appears to be particularly important as a driver of innovation, both in terms of inventive activity and in terms of the communication processes involved in knowledge transfer in diffusion."[450]

History, as well as current learning, demonstrates that CCS costs will decline significantly, and any operational issues will be remedied in the short term. In the context of the forward-looking, technology-forcing section 111(b), EPA must take this reality into account.

b. EPA failed to consider EOR revenue and the recent expansion to CCS tax credits.

As discussed above, in 2015, EPA found that the cost of CCS was reasonable even without considering revenue from selling the CO_2 to EOR operators or receiving tax credits. However, this finding does not excuse EPA from considering these offsets in its decision *not* to base standards on CCS. The purpose of the Clean Air Act is to reduce pollution from new sources to the maximum feasible extent and therefore EPA must take all cost reductions into account when setting standards for new coal-fired power plants. An agency rulemaking is arbitrary and capricious if it "entirely failed to consider an important aspect of the problem,"[451] and "[m]erely to look at only one side of the scales . . . flunks this basic requirement."[452] EPA "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[453]

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445 *See generally* Mike Laney, RTI Int'l, History of Flue Gas Desulfurization in the United States – 1970-1976, Doc. ID: EPA-HQ-OAR-2013-0495-11774 (July 11, 2015); Br. for *Amicus Curiae* Technology Innovation Experts, *supra* note 419, at 5; *see also* Margaret Taylor et al., *Regulation as the Mother of Innovation: The Case of SO2 Control*, 27 L. & Pol'y 349, 357 (2005), http://content.ccrasa.com/library_1/30451%20-%20Regulation%20as%20the%20Mother%20of%20Innovation,%20The%20Case%20of%20SO2%20Control.pdf.

446 Br. for *Amicus Curiae* Technology Innovation Experts, *supra* note 419, 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 Taylor et al., *supra* note 445, at 356).

447 Taylor et al., *supra* note 445, at 369.

448 Mike Laney, *supra* note 445, at 5-6.

449 Margaret Taylor et al., *Control of SO2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.*, 72 TECH. FORECASTING & SOC. 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.

450 80 Fed. Reg. at 64,572 (explaining that CCS would not become more widely deployed without a regulatory framework or price signal for CO_2, which would allow for cost recovery); *see also* Mike Laney, *supra* note 445.

451 *State Farm*, 463 U.S. at 43.

452 *California v. BLM*, 277 F. Supp. 3d 1106, 1122 (N.D. Cal. 2017).

453 *Ctr. for Biological Diversity*, 538 F.3d at 1198.

As discussed above, at Part III.B.2., EOR projects must purchase CO_2 for their operation, providing CCS projects with a buyer for their captured CO_2 and a source of revenue. In 2015, EPA concluded that it "may, of course consider revenues generated as a result of application of pollution control measures in assessing the costs of a best system of emission reduction."[454] EPA recognized that "EOR can significantly lower the net costs of implementing CCS" and that 70 percent of new projects under construction or in advanced planning intend to utilize it.[455] While EOR revenue varies based on oil price and operator, in the Proposal, EPA assumes $22/tonne.[456] The Proposal however, assumes *no revenue* from the sale of CO_2 when calculating the LCOE for CCS because "there are places where opportunities to sell captured CO_2 for utilization may not be presently available."[457] As described below at Part III.E., EPA must design standards to be achievable under the most adverse conditions *likely to recur* – a coal-fired power plant built for fuel diversity purposes is already at an economic disadvantage, as compared to a gas plant, and it has the option to build in the most economically advantageous area and utilize pipelines and transmission lines to ensure access to additional revenue while still serving its customers. It is unreasonable to ignore the predominant business model under which CCS projects are being built, see Part III.A.1. above.

In 2015, while still finding the costs of CCS reasonable, EPA did not consider tax revenue or EOR revenue other than to point to them as more than enough to offset any requirements under the Greenhouse Gas Reporting Rule.[458] However, 45Q has significantly changed since 2015. In February 2018, 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.[459] 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.[460]

Although a project must begin construction by the close of 2023, the provision does not establish any deadline for completion of construction and "commencing construction" is currently undefined.[461] 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/tonne for CO_2 stored through EOR. For saline storage, the

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454 80 Fed. Reg. at 64,559 n.252 (citing *New York*, 969 F.2d at 1150-52).
455 *Id.* at 64,566.
456 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. For an illustration of the range of EOR prices in Wyoming under various oil price scenarios, see Benjamin R. Cook, University of Wyoming, *Wyoming's Miscible CO_2 Enhanced Oil Recovery Potential from Main Pay Zones: An Economic Scoping Study* (Nov. 2012), http://www.uwyo.edu/cee/_files/docs/2012_cook_wyomings_miscible_co2_eor_potential.pdf.
457 83 Fed. Reg. at 65,440.
458 80 Fed. Reg. at 64,591.
459 Bipartisan Budget Act of 2018, Pub. L. No. 115-123, § 41119, 132 Stat. 64, 162 (2018); *see also* Timothy Gardner, *supra* note 424.
460 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.
461 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. 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.*

credit value reaches $50/tonne for CO_2 following a 10-year ramp. After 2026 the credit is adjusted to increase with inflation.

The change represented a major departure from the previous 45Q credit. 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, the credit was capped at 75 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 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. Such a project could be economic with 45Q credits and the previously discussed 20 percent reduction in Petra Nova costs as illustrated by the figure below:[462] The company behind Petra Nova's capture technology, MHI, agrees stating that "the market for carbon capture in the U.S. is especially ripe, owing to a boost from the 45Q tax incentives."[463]

Figure 17: NRG Energy CCS Cost Curve Estimates

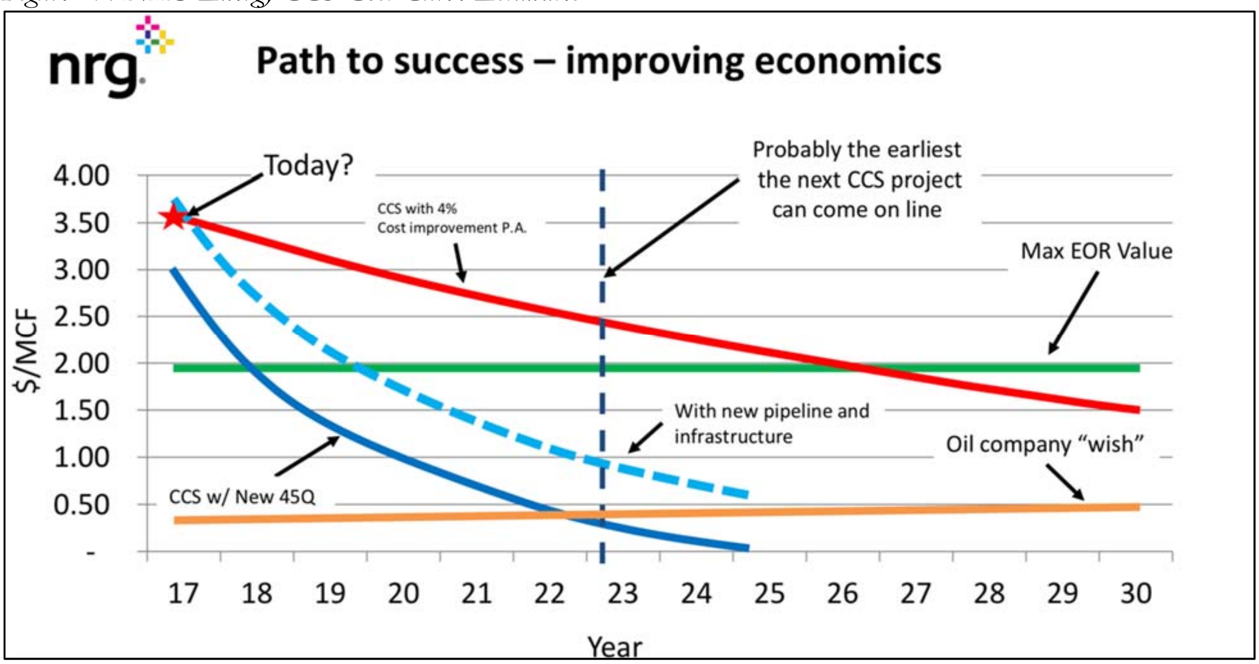

Image Source: David Greeson, NRG Energy

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 an operator might choose to build a CCS project without incentives. The orange line represents what EOR operators 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

[462] CATF & NRDC, Comments, *supra* note 57, at Attach. D (David Greeson, *Petra Nova Capture Project*, GHGT-14 (Oct. 2018)).
[463] Sonal Patel, *supra* note 101.

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. While uncontrolled coal plants are not economical under any circumstances, by the time the next plant could come on line, 45Q makes CCS-EOR economically attractive.

Like those at Petra Nova, Mike Monea, who led 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.[464]

EPA entirely ignores the dramatically expanded 45Q in the Proposal because in order to qualify for the current iteration of the tax credit the facility must "commence construction before January 1, 2024…which, in turn, is before the end of the 8-year period in which EPA is required to review and, if necessary, revise the standard of performance."[465] This reasoning, however, does not withstand scrutiny. The 45Q legislation was enacted to support additional CCS projects, which as described above will reduce costs through learning-by-doing. Therefore, the expectation is that once the credit expires, costs will have declined such that the industry no longer needs it. In discussing the impact of 45Q, MHI recently stated that "more plants on the ground will drive down costs of the relatively new technology."[466] However, even if this is not the case, the original 45Q was finalized in 2008, and ten years later Congress more than doubled one incentive and more than tripled the other. One would anticipate that similar to renewable energy production tax credits, 45Q will be extended and expanded before 2027 if credits are still necessary. Second, EPA must review the standard and revise, if necessary, "*at least* every 8 years."[467] If costs have not sufficiently declined and/or the credit has not been extended, EPA can undertake a review of the standard at that time. This Proposal proves the point: EPA decided to review the current standard merely three years after it was finalized. It is nonsensical that the Agency would ignore this substantial credit, which was designed to reduce costs without additional support, especially because EPA always has the option to revise the standard based on evolving circumstances.

Additionally, the 48A tax credit provides a qualifying advanced coal project credit for any taxable year in an amount equal to 30 percent of the qualified investment.[468] A coal-fired project separating and sequestering 65 percent of its CO_2 emissions qualifies for the credit.[469] And moreover, the highest priority is given to projects with greenhouse gas capture capability.[470] On February 8, 2019, the Carbon Capture Modernization Act was introduced in the Senate to further incentivize CCS projects through 48A.[471]

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[464] Michael Monea, *supra* note 141.
[465] 83 Fed. Reg. 65,440.
[466] Sonal Patel, *supra* note 101.
[467] 42 U.S.C. § 111(b)(1)(B) (emphasis added).
[468] 26 U.S.C. § 48A(a).
[469] *Id.* at § 48A(e)(1)(G).
[470] *Id.* at § 48A(e)(3)(B)(1).
[471] Sens. Hoeven & Smith, *Carbon Capture and Modernization Act* (Feb. 2019), https://www.hoeven.senate.gov/imo/media/doc/Carbon%20Capture%20Modernization%20Act%20One-Pager.pdf.

Agency reasoning must reflect reality[472] and "adapt as critical facts change."[473] These EOR revenues and tax credits are available and reflect the critical ingredients for any business plan to build a new coal-fired power plant. To ignore the most likely business case for a new coal plant in a low carbon world is arbitrary and capricious.[474] [475]

c. NRDC's modeling confirms that the Proposal mischaracterizes CCS by failing to consider factors affecting the technology's costs.

As discussed in greater detail in the comments to the ACE Proposal, NRDC conducted in-depth modeling demonstrating that the deployment of CCS on coal and gas plants results in significant emission reductions at reasonable costs.[476] NRDC ran a series of scenarios using the IPM model, imposing performance targets for existing coal and gas power plants. Those targets are designed based on a best system that includes CCS. While the modeling was centered on designing a meaningful and cost-effective best system of emission reduction for existing coal and gas units under the umbrella of Clean Air Act section 111(d), it still provides valuable insight into factors affecting the economics of CCS and, by extension, into the shortcomings of EPA's sweeping assumptions in this rulemaking.

The NRDC modeling showed that properly accounting for the 45Q tax credit, as well as the revenues from the sale of carbon for EOR applications, is an important driver of CCS buildout by 2030. When added to the total carbon capture costs, the 45Q tax credits and EOR payments put significant downward pressure on total carbon capture and transportation costs, reducing those costs between 30 percent and 72 percent by 2030, depending on the modeled scenario.[477] These results confirm that it is critical for EPA to incorporate the degree to which the combination of the 45Q tax credits and EOR revenues can improve the economics of new CCS plants.

In addition, the large near-term deployment of CCS points to the potential for significant technology cost declines beyond 2024 as experience increases. While the NRDC modeling was conservative in that it assumed no "learning-by-doing" cost declines, we estimate the learning curve could decrease costs by up to 27 percent by 2030, assuming the level of near-term CCS deployment in NRDC's no carbon policy case.

The following sections highlight key results from the NRDC section 111(d) modeling. Greater detail and a description of the modeling assumptions are included in Appendix B.

i. EPA failed to meaningfully consider EOR potential.

New coal plants can be sited in proximity to EOR fields

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472 *Chem. Mfrs. Ass'n*, 28 F.3d at 1265; *see also API*, 862 F.3d at 68.
473 *Flyers Rights Educ. Fund*, 864 F.3d at 745.
474 *State Farm*, 463 U.S. at 43 ("Normally, an agency rule would be arbitrary and capricious if the agency . . . entirely failed to consider an important aspect of the problem . . . .").
475 Br. of *Amicus Curiae* Saskatchewan Power Corp., *supra* note 137, at 5-7 (presenting business case for building Boundary Dam).
476 For a more detailed discussion of the NRDC modeling, refer to NRDC and CATF's Comments, *supra* note 57.
477 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.

As discussed in Part III.B. of these comments, plants can be sited closer to storage and EOR sites and provide electricity to customers through transmission lines. Therefore, EPA cannot rule out CCS technology on the grounds that EOR potential is not universally or widely available.

The NRDC modeling highlights the economic opportunity for siting CCS projects in proximity to EOR fields and existing CO_2 pipeline infrastructure. The reference case, which includes no policy on carbon emissions, shows more than 8 GW of CCS retrofits on coal power plants by 2025. All of the retrofitted capacity is located in four states- Texas, New Mexico, Montana and Louisiana. These states have large EOR potential and house, or are in proximity to, existing CO_2 pipeline infrastructure. Thus, CCS projects are sited in these locations 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. This highlights the large economic potential for CCS in some regions and EPA's shortcomings in failing to consider the option for new plants to be sited in proximity to EOR fields and tap into the abundant electricity transmission infrastructure to deliver power to demand centers.

Economic opportunities for CCS projects are widely available, beyond locations in proximity to EOR fields.

The wide geographic distribution of CCS deployment in the NRDC modeling confirms that CCS is broadly available. In particular, one of the scenarios imposes emissions rates targets on coal-fired power plants based on the deployment of 55 percent carbon capture at each coal plant. 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. The table 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 in this scenario.[478] These findings confirm the non-localized availability of EOR opportunities, as well as the potential for power plants to take advantage of a wide network of existing CO_2 pipelines at modest cost to tap into the EOR potential.[479]

Table 4: Post-capture costs and 45Q subsidies for run labeled "CCS-1" ($ millions)

	2020	2025	2030	2035
45Q tax credits	$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 consider CCS to be the best system for new coal plants: the 45Q credits, coupled with the large opportunities to sell captured carbon for EOR applications create a large potential for economic CCS projects. EPA should meaningfully evaluate the technology by accounting for these material factors and maintain CCS as the best system of emission reduction for new coal plants.

[478] 33 GW of coal retrofits by 2030.
[479] Existing CO_2 pipeline infrastructure is discussed in greater detail in Part III.B.2.b

ii. Near-term CCS deployment can be expected to significantly lower technology costs beyond the phaseout of 45Q.

The large deployment of CCS retrofits on coal plants by 2030 demonstrates that technology costs are already reasonable for CCS retrofits. However, this result also provides a crucial indicator into how carbon capture technology costs, for both retrofits and new plants, would decline as a result of this increased experience and the typical "learning-by-doing" effect.

The NRDC modeling was conservative in the following two aspects: first, it adopted the set of carbon capture costs and assumptions embedded in IPM version 6.[480] Those costs assume a carbon capture technology whereby the steam and electricity needed to run the post-combustion capture unit are pulled from the coal plant's steam cycle. These assumptions result in poorer economics for both coal retrofits with CCS and new coal CCS plants.[481] In addition, the NRDC modeling assumes the same minimal technology cost declines resulting from the large near-term CCS deployment as embedded in IPM version 6.[482] Those already minimal cost declines come to a freeze in 2025 through 2050. This approach runs counter to how costs would realistically behave and neutralizes the significant impact that the 45Q tax credits would have on carbon capture costs beyond their phaseout in 2024. Given this modeling shortcoming, we estimate below the potential cost declines for carbon capture technology resulting from the near-term deployment of CCS coal retrofits. This demonstrates that EPA should thoroughly consider the impacts of 45Q on carbon capture costs in determining an appropriate best system for new coal plants.

The NRDC runs show various levels of coal CCS retrofits by 2030, ranging from 8-47 GW, depending on the assumed policy ambition.[483] For purposes of this exercise, the cost estimate below will only be based on the no-carbon-policy ("No CPP") run, which shows 8.2 GW of coal CCS retrofits by 2030 absent any limit on carbon emissions. The deployed capacity is driven primarily by the availability of 45Q credits, as well as EOR payments.

The following table shows carbon capture costs that exclude the impact of 45Q tax credits, EOR revenues and carbon transportation costs. As shown below, those costs do not reflect any cost decline from increased deployment of CCS.

Table 5: CCS coal retrofits and carbon capture costs in the No CPP case[484]

	2020	2030	2035
CCS coal retrofits (cumulative capacity in GW)	-	8.2	8.2
Capture Costs (2012 $/tonne)	-	$56	$56

[480] The full set of assumptions underpinning the NRDC modeling are listed in Appendix B of these comments, as well as NRDC and CATF's Comments, *supra* note 57.
[481] In contrast, and as discussed in greater detail in Part III.A.1 of these comments, the Petra Nova model can potentially lead to better plant economics, including better dispatch flexibility.
[482] Carbon capture costs embedded in IPM version 6 can be found at the following link: 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.
[483] The NRDC modeling runs are discussed in greater detail in NRDC and CATF's Comments, *supra* note 57.
[484] Note that 45Q tax credits and EOR revenues significantly reduce the $/tonne costs compared to what is tabulated.

Rubin *et al.* estimate the learning curve for CCS on coal plants.[485] The learning rates, defined as the fractional reduction in costs for each doubling of cumulative capacity, are estimated to be 1.1-9.9 percent for coal plants with CCS. This means that at the level of CCS deployed in the No CPP case ($56/tonne), and at an improvement rate of 9.9 percent, capture costs would likely drop by 27 percent by 2030 and reach $40/tonne.[486] Adopting the more accurate $45-47/tonne range as an initial cost point for the next carbon capture plant—instead of the $56/tonne figure—carbon capture costs are likely to drop to $33-34/tonne by 2030, assuming a learning rate of 9.9 percent.[487] This is very close to the DOE CCS program goal of $30/tonne by 2030. Therefore, it is reasonable to conclude that the 45Q tax credits will have a large impact on technology costs. This is precisely how a tax credit is meant to work—bring technology costs down by incentivizing deployment. By failing to evaluate the impact of the 45Q credits due to their planned phaseout, EPA negates the primary purpose of tax credits.

In conclusion, the NRDC modeling shows that the 45Q tax credits and EOR opportunities have a significant impact on the economics of CCS, and EPA failed to consider both factors in evaluating the technology. In addition, the projected near-term deployment of CCS driven primarily by the 45Q tax credits is likely to have significant impacts on carbon capture costs. By failing to consider this typical learning-by-doing dynamic, EPA completely negates the impact of the 45Q tax credits. EPA must conduct a full analysis that accounts for these dynamics.

d. CCS is still in line with the LCOE for the other baseload low-emission technology.

In 2015, EPA reviewed Integrated Resource Plans (IRP) and other available information "to determine the types of technologies that utilities are considering as options for new generating capacity" and the value of fuel diversity.[488] The Agency concluded that while the bulk of new units were expected to be natural gas-fired power plants, new coal-fired power plants, nuclear plants[489] and biomass power plants[490] were under consideration to provide fuel diversity among dispatchable baseload generating technology to those customers willing to pay a premium for that diversity.[491]

Therefore, EPA determined that a reasonable means of considering costs would be to compare the levelized cost of electricity (LCOE) of these non-natural gas, baseload, generation sources. Again, the LCOE for CCS was based on a range of conservative options, but nonetheless was found to be in line with analogous sources of lower-emitting, baseload generation.[492]

485 Rubin et al., *supra* note 438, at 218.
486 This assumes a starting point of $55/tonne for the first GW of coal retrofitted with CCS.
487 As discussed in Part III.C.3.a. above, NRG and SaskPower estimate that their next carbon capture plants would cost $45-47/tonne.
488 80 Fed. Reg. at 64,561.
489 *Id.* at 64,566; EPA, Response to Comments, Cost and Benefits, at 3-95, Doc. ID: EPA-HQ-OAR-2013-0495-11862 (Oct. 23, 2015) ("Further indicia that new nuclear capacity is possible are actual construction of new nuclear capacity in recent years (Vogtle Electric Generating Plant, Watts Bar Generating Station). The leading technical economic journals likewise continue to view nuclear as a viable future technology. *See, e.g.* Glob. CCS institute, 'The Costs of CCS and Other Low-Carbon Technologies (2015 update)[') at 1 ('[n]uclear generation plant … can also be cost competitive in some markets given [its] high utilization rates (i.e. can be operated up to 80 to 90 percent of the time)').").
490 CATF *et al.*, submitted separate comments to this docket today on the treatment of biomass in this rulemaking.
491 80 Fed. Reg. at 64,561-62.
492 *Id.* at 64,561 tbl. 8.

In addition to its similar treatment in IRPs, EPA supported its determination that the price of nuclear was a relevant metric to compare to CCS by reviewing reports and industry statements. AEP Vice President Macnaughton "presented findings from a recently-conducted cost analysis showing that the cost of electricity generated by coal and natural gas plants equipped with CCS is competitive with other low or no-carbon energy carbon energy sources, such as wind, solar, geothermal, hydro and nuclear."[493] The Agency also cited the Global CCS Institute, which documented that "CCS is a cost competitive power sector emissions reduction tool when considered among the range of available low and zero emissions technologies" and provides LCOE estimates using a common methodological framework which are consistent with those of other recognized expert entities with respect of cost of full CCS and cost of nuclear power.[494]

EPA now proposes to reject this comparison as reasonable because new nuclear builds are not forecasted. However, neither are new coal plant builds – and EPA recognized both projections in 2015. Like new coal-fired units, the 2015 Regulatory Impact Analysis did not predict any new nuclear builds under most scenarios and only saw 2.5 GW under a low gas and oil resource scenario in 2020.[495] And the demand for new nuclear and coal-fired power plants continue to be similarly affected by the changing market conditions. EIA recently found that due to historically low natural gas prices and other market conditions, increased natural gas-fired generation, intermittent renewables, and additional retirement of less economic coal and nuclear plants occur during the 2019-2050 period.[496] These two baseload generation technologies, available to diversify the generation mix and hedge against carbon pricing, continue to hold comparable positions in the electric market and therefore comparing the LCOE of CCS is still appropriate.

In the Proposal, EPA dismisses the comparison with biomass power plants because those plants are generally smaller and with nuclear because two new plants are experiencing cost overruns.[497] These factors, however, would seem to make CCS *more* attractive, not less. Moreover, cherry-picking anecdotal discussions of the two AP1000 nuclear projects in Georgia and South Carolina,[498] which experienced uncharacteristic delays and cost overruns associated with design and mismanagement issues, is no substitute for actually updating and reviewing the LCOE for nuclear. Analysis from Lazard and EIA are updated annually, highly scrutinized and widely used in the energy sector. Below, we see that since 2015, the LCOE for nuclear is directionally a mixed bag. The Lazard LCOE range for new nuclear generation has increased and the range expanded, however the high end of the EIA range has declined.

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493 EPA, Response to Comments, Standards for Fossil Fuel-Fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-216, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).
494 *Id.* at 6-221 (citing Glob. CCS Inst., supra note 489, at 1).
495 2015 RIA, at 4-14 tbl. 4-3.
496 EIA, *supra* note 376, at 12.
497 83 Fed. Reg. at 65,437.
498 Kristi E. Swartz, *Nation's Sole Nuclear Project Shifts into Testing Phase*, ENERGYWIRE (Feb. 21, 2019) (explaining that after changing contractors, Plant Vogtle's schedule and cost forecast are on target).

Table 6: Nuclear Levelized Cost of Energy

	2015 - $/MWh[499]	2018 - $/MWh
EIA	87-115	89.7-97.5[500]
Lazard	92-132	112-189[501]

While the current market conditions make it unlikely that new coal or convention nuclear will be built in the near term, the cost overruns at two nuclear plants do not render the nuclear generation LCOE a useless metric. It is the other baseload, low-emitting generation technology available, and is being similarly affected by market conditions - even at EPA's unreasonably high $122.8/MWh for CCS, nuclear and CCS costs are comparable.

Additionally, EPA fails to update the review of IRPs to determine what the real-world role new coal-fired power plants and CCS may play in the next decade, or to determine what other non-gas units may also be built for fuel diversity purposes. Instead, EPA indicates that it "has not received information since the 2015 Rule that would cause it" to change its conclusions.[502] EPA cannot, however, sit back and wait to "receive" information - it is an expert Agency, that must undertake intensive investigation to substantiate its claims. Moreover, it is required to engage with the record underlying the rule it is proposing to upend.[503] Without updating its IRP analysis, it is difficult to assess what generation sources are analogous to CCS coal-fired power plants for the purpose of analyzing cost. EPA cannot dismiss the comparison to nuclear generation without further analysis.

A cursory review of recent IRPs indicates that almost all of them have been updated, some many times over. While fuel diversity continues to be important, in the face of climate change and potential future carbon regulation, building a diverse mix of *low-emitting*, new generation sources is even more important.[504] For example, in one of the most recent IRP updates, Dominion Energy stated that "[d]espite the current uncertainty regarding future federal policies, the Company believes that carbon regulation of power station emissions is virtually assured in the future."[505] Therefore, as

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499 80 Fed. Reg. at 64,568 tbl. 10.

500 EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018*, at 7 tbl. 2 (Mar. 2018), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

501 Lazard, *Lazards Levelized Cost of Energy Analysis, Version 12.0*, at 2 (Nov. 2018), https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

502 83 Fed. Reg. at 65,436.

503 *Fox Television Stations*, 556 U.S. at 515-16 (internal citation omitted). If an agency changes course, it must "provide a more detailed justification than what 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 or capricious to ignore such matters." *Id.* at 515.

504 *See, e.g.*, Duke Energy Progress, *North Carolina Integrated Resource Plan* (Sept. 5, 2018), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=25fb3634-54b6-464b-9704-b6fe99cda1a8 (describing plan to reduce CO_2 emissions by at least 40% by 2030, considering carbon constrained future, and relying on "diverse mix of energy efficiency, demand side management, renewable energy and natural gas" to meet new capacity demands); Tenn. Valley Auth., *2019 Integrated Resource Plan, Vol. I – Draft Resource Plan* (Feb. 15, 2019), https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/2019%20Documents/TVA%20Draft%20IRP%20Vol%20I-reduced.pdf (considering decarbonized future and planning for a "flexible power generation system that can successfully integrate increasing amounts of renewable energy and distributed energy resources"); Dominion Energy, *Virginia Electric and Power Company's Report of Its Integrated Resource Plan* (May 1, 2018), https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf (reflecting the "transition to a lower emission rates future" and considering a federal CO_2 program).

505 Dominion Energy, *supra* note 504, at 6.

IEA recently recognized, "those systems which offer flexibility, reliability, and the use of indigenous fuel supplies whilst helping to mitigate CO_2 emissions, will be at a distinct advantage."[506] This is the future the utilities are planning for and it is EPA's duty under section 111 to take this reality into account and lead.

In 2015, EPA recognized this duty when it catalogued industry statements indicating that CCS will not become widely deployed without a regulatory price signal, which allows for cost recovery and attracts investors[507] The same goes for new nuclear power. For example, Dominion Energy obtained an operating license to add a new unit at an existing nuclear plant but due to "uncertainties of future carbon regulation, the Company has determined it is prudent to pause material development activities."[508]

As EPA recognizes, in this market, natural gas is the obvious economic choice, but outside of that, CCS and nuclear are still the two alternative baseload technologies that utilities are considering, especially under the anticipated carbon-controlled future.[509] Secretary Perry recently confirmed that "Without carbon capture, any climate target is virtually impossible to meet, We believe that you can't have a serious conversation about reducing emissions without including nuclear energy and carbon capture technology."[510] EPA structured the standard to ensure that new coal capacity can be both lower CO_2-emitting and cost competitive with other non-gas baseload dispatchable capacity. Nothing in the Proposal demonstrates that these objectives are no longer achievable.

4. CCS costs are comparable to costs imposed by previous rulemakings.

In this Proposal EPA finds that the capital costs of partial-CCS are not reasonable because such costs are greater on an absolute basis than prior emission standards.[511] The Proposal asserts that "additional environmental control requirements increase the baseline costs of constructing a new coal-fired power plant. Therefore, at the same percentage increase in capital costs, absolute costs are much higher."[512] This analysis is flawed and contrary to caselaw assessing the reasonableness of pollution control costs.

Evaluating a pollution control system's costs in absolute terms is unreasonable – the economic value of the project will be determined by looking to the projected return on investment, which is expressed as a percentage of the investment. Whether a pollution control system is excessively costly is properly determined by considering how much the system will reduce the expected return on investment—i.e., by considering the percentage increase in project costs. For this reason, courts

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[506] Dr. Lesley Sloss, IEA Clean Coal Ctr., *Technology Readiness of Advanced Coal-Based Power Generation Systems*, at 15 (Feb. 2019), https://www.iea-coal.org/technology-readiness-of-advanced-coal-based-power-generation-systems-ccc-292/.
[507] 80 Fed. Reg. at 64,572.
[508] Dominion Energy, *supra* note 504, at 73-74.
[508] 83 Fed. Reg. 65,440.
[509] *See, e.g.*, Tenn. Valley Auth., *supra* note 504, at 5-6, 7-3; Dominion Energy, *supra* note 504, at 73-74.
[510] Kelsey Brugger, *Perry Announces $24M for CCS, Talks Emissions*, GREENWIRE (Feb. 28, 2019), https://www.eenews.net/greenwire/2019/02/28/stories/1060122691.
[511] 83 Fed. Reg. at 65,440.
[512] *Id.*

have traditionally looked at the percentage increase in the project costs in evaluating whether the costs of a pollution control system are reasonable.[513]

Indeed, one of the cost metrics EPA considered in 2015 was the incremental capital costs required for a plant to meet the standard.[514] In 2015, EPA predicted that "the incremental costs of control for a new highly efficient SCPC unit to meet the final emission limitation of 1,400 lbs. CO_2/MWh-g would be an increase of 21–22 percent for capital costs."[515] The Agency found the costs of partial-CCS reasonable "because they are comparable to those in prior regulations and to industry experience, and because the fossil steam electric power industry has been shown to be able to successfully absorb capital costs of this magnitude in the past."[516]

Previous standards for new fossil steam units have imposed significant but manageable capital costs. The 2015 rule identified several prior new source performance standards that resulted in incremental capital cost impacts of comparable magnitude, to which industry was able to adjust:

- The 1971 NSPS for coal-fired power plants imposed estimated costs of $19 million, a capital cost increase of 15.8 percent above the $120 million cost of a new plant.[517] The D.C. Circuit upheld EPA's determination that the costs of the standard were reasonable.[518]
- The 1978 NSPS for coal-fired power plants was estimated to impose cumulative incremental capital costs of up to $10 billion from 1976 to 1995.[519] The D.C. Circuit upheld the standard, including EPA's finding of cost reasonableness.[520] A 1982 analysis by the Congressional Budget Office (CBO) found that the controls required by the 1978 NSPS increased capital costs for new power plants by up to 20 percent.[521]
- The 1971 NSPS for portland cement plants were estimated to increase capital costs by 12 percent.[522] The D.C. Circuit upheld EPA's consideration of costs;[523] after remand, the court again upheld the standard and concluded that "industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed."[524]

The 1982 CBO study noted that capital costs for new coal-fired power plants increased by 150-180 percent from 1971 to 1980 – of that total increase, approximately 25 percent was attributable to air pollution control requirements, while "cost escalations in basic materials and construction" were responsible for the remaining 75 percent.[525] The CBO concluded that "controlling emissions . . . has

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513 *See, e.g.*, *Portland Cement*, 486 F.2d at 387.
514 80 Fed. Reg. at 64,559-60.
515 *Id.* at 64,560.
516 *Id.* at 64,559.
517 *Id.* at 64,560.
518 *Essex Chemical*, 486 F.2d at 440.
519 44 Fed. Reg. 33,580, 33,609 (June 11, 1979).
520 *Sierra Club*, 657 F.2d at 332, 410.
521 80 Fed. Reg. at 64,560.
522 *Id.*
523 *Portland Cement,* 486 F.2d at 387-88.
524 *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).
525 CBO, *The Clean Air Act, the Electric Utilities, and the Coal Market*, at 22 (Apr. 1982), https://www.cbo.gov/sites/default/files/97th-congress-1981-1982/reports/doc14b-entire_1.pdf.

not played a major role in impairing the utilities' financial position, and is not likely to do so in the future."[526]

That the capital cost to build highly-polluting coal-fired power plants increases as more pollutants are controlled to safer levels is in line with the purpose of the statute. Congress intended that new source performance standards "should be stringent in order to force the development of improved technology."[527] In service of that technology-forcing goal, Congress instructed that "the costs of applying best practical control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business."[528] Allowing a power plant to forego cost-effective control requirements for one dangerous pollutant simply because a new plant owner already faces costs to control other harmful pollutants contradicts the mandate of the Clean Air Act.

5. EPA's proposed upward adjustments to outdated cost figures are unjustified.

As described above, EPA is blindly relying on 2015 "Cost and Performance Studies" that have been superseded by less costly CCS technology and do not take into account declining costs, EOR revenues or tax credits. But not only is EPA relying on unreasonably high, outdated information, it is unjustifiably inflating those costs.

a. Cost of transportation and sequestration

If a new CCS plant captures a small amount of CO_2 and builds its own pipeline to a storage location, it will incur costs associated with looping and compressing that low volume of CO_2 through the pipeline as well as building the entire pipeline itself. This, however, is a most unlikely scenario. A new CCS plant would likely capture more CO_2 than the low rates required to meet the 1,400 lbs./MWh standard, especially with 45Q available, and would also utilize existing CO_2 infrastructure and comingle its emissions with other sources using the pipeline. Yet, instead of using transportation and storage (T&S) costs that reflect a reasonable scenario, EPA assumes the worst-case: low capture rates and an isolated new plant building a complete point-to-point pipeline for its sole use.[529] To reflect the worst case scenario EPA adjusts the T&S costs used in its LCOE calculation from the $11/tonne costs assumed in 2015, to $20 and $30/tonne for low-rank and bituminous coal plants respectively.[530]

In 2015, EPA concluded that "[p]ipelines are the most economical and efficient method of transporting CO_2 from commercial CCS facilities geologic storage sinks such as saline formations, coal seams, and oil and gas fields."[531] The T&S cost estimates of $5-15 were based on costs developed in the UIV Class VI rulemaking proceeding and reflect the cost of site screening and evaluation, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long term liability protection. These costs reflect the regulatory requirements of the Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. The T&S costs provide a *conservative* estimate of

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[526] *Id.* at xvi.
[527] *Sierra Club*, 657 F.2d at 325 (citing H.R. Rep. 95-294 (1977)).
[528] H.R. Rep. 95-294, at 184 (1977).
[529] 83 Fed. Reg. at 65,438.
[530] *Id.* at 65,439 tbl. 6.
[531] EPA, Technical Support Document: Literature Survey of Carbon Capture Technology, at 22, Doc. ID: EPA-HQ-OAR-2013-0495-11773 (July 10, 2015).

storage costs in that they assume storage in a formation until the total mass of CO_2 injected from all projects approaches 40 percent of the theoretical storage capacity consistent with cases modeled in the NETL report.

EPA also recognized and considered that T&S costs may vary geographically and depend on the flow rate of CO_2, and the number of sources utilizing the pipeline. However, considering the conservative assumptions described above, the Agency determined that the studies and DOE quality guidelines, which place CO_2 pipeline transport costs in the $1-4/tonne of CO_2 range, are correct.[532]

In 2015 EPA stated "that the technical and economic feasibility of operation of CO_2 pipelines [does not] depend upon steady-state generation of CO_2 from capture sources. There are technically and economically feasible technologies (e.g., looping, pressure maintenance, and diversion to/from other pipelines) that EGUs and CO_2 pipeline can apply to manage pipeline pressure and flow fluctuations associated with EGU load fluctuations and EGU planned or unplanned outages to avoid detrimental effects on CO_2 pipeline operations."[533]

As of August 2015, 96 facilities were reporting a total of 64 MMT of CO_2 injected underground in the U.S. – while EPA has not updated those numbers since that time, it is likely that the underground CO_2 injection industry has only expanded in the interim.[534] As seen below, capture and producers of CO_2 , as well as underground injection sites, are located throughout the country along with their attendant CO_2 T&S infrastructure. A new plant would choose a site amenable to utilizing the CO_2 infrastructure in place currently accommodating any of these sources to achieve the economies of scale represented by EPA's 2015 value of $11/tonne. Additionally, including the sale of CO_2 for EOR would greatly reduce T&S costs or even turn them into negative numbers, and finally, plants may opt to sequester directly below their site and eliminate transport costs.

Therefore, a new plant would be much more likely to exploit the economies of scale and the $9.6-16/tonne costs that the Proposal lists for higher capture volumes[535] are more reasonable than the $20 and $30/tonne[536] that EPA chose to use in determining the total costs of CCS for low-rank and bituminous coal plants respectively.

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532 EPA, Response to Comments, Standards for Fossil Fuel-Fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-107, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).
533 *Id.* at 6-41 to 6-42.
534 EPA, *Greenhouse Gas Reporting Program – Capture, Supply, and Underground Injection of Carbon Dioxide*, https://www.epa.gov/ghgreporting/capture-supply-and-underground-injection-carbon-dioxide (last visited Feb. 21, 2019).
535 83 Fed. Reg. at 65,438 tbl. 5.
536 *Id.* at 65,439 tbl. 6.

Figure 18: Map of CO_2 Capture and Underground Injection Reported to EPA's GHG Reporting Program

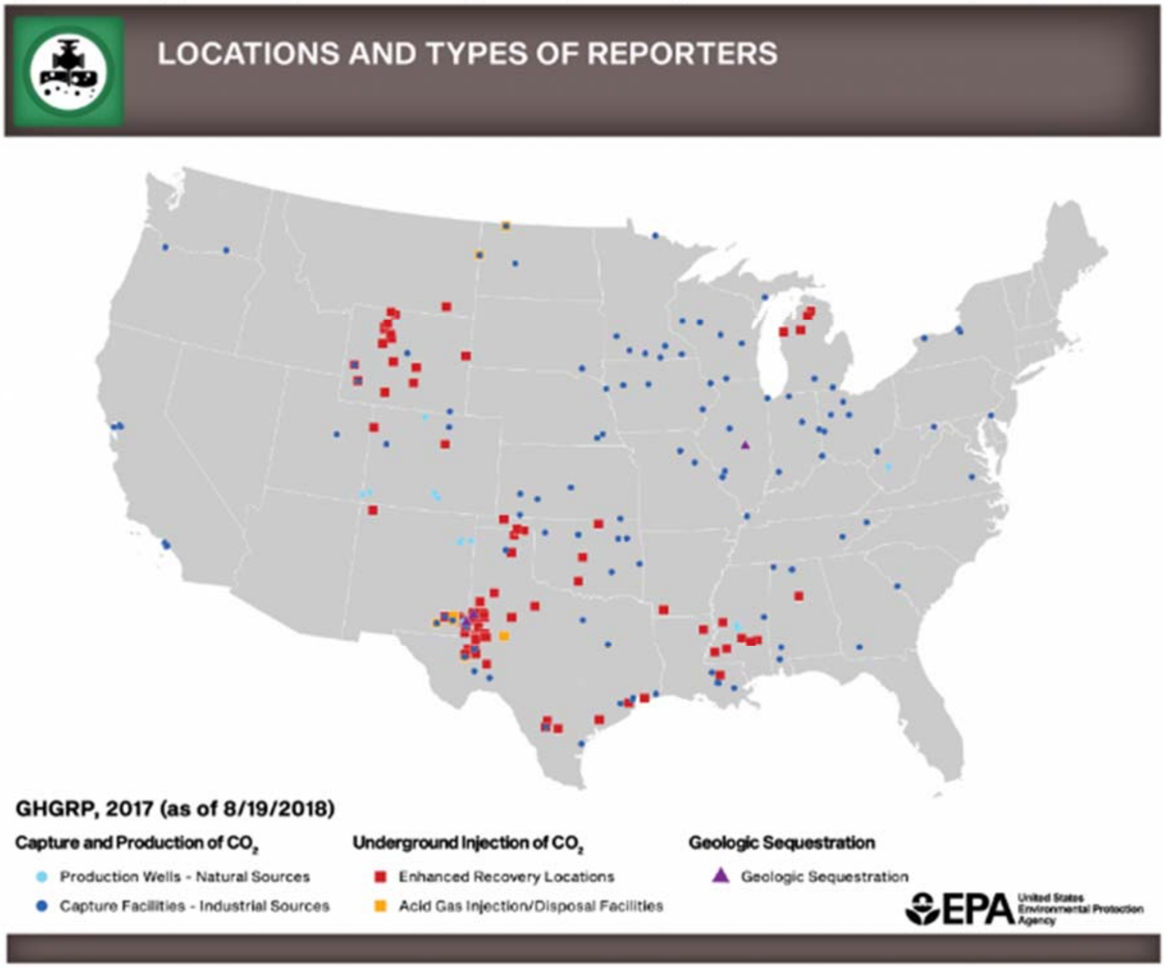


Image Source: EPA Greenhouse Gas Reporting Program[537]

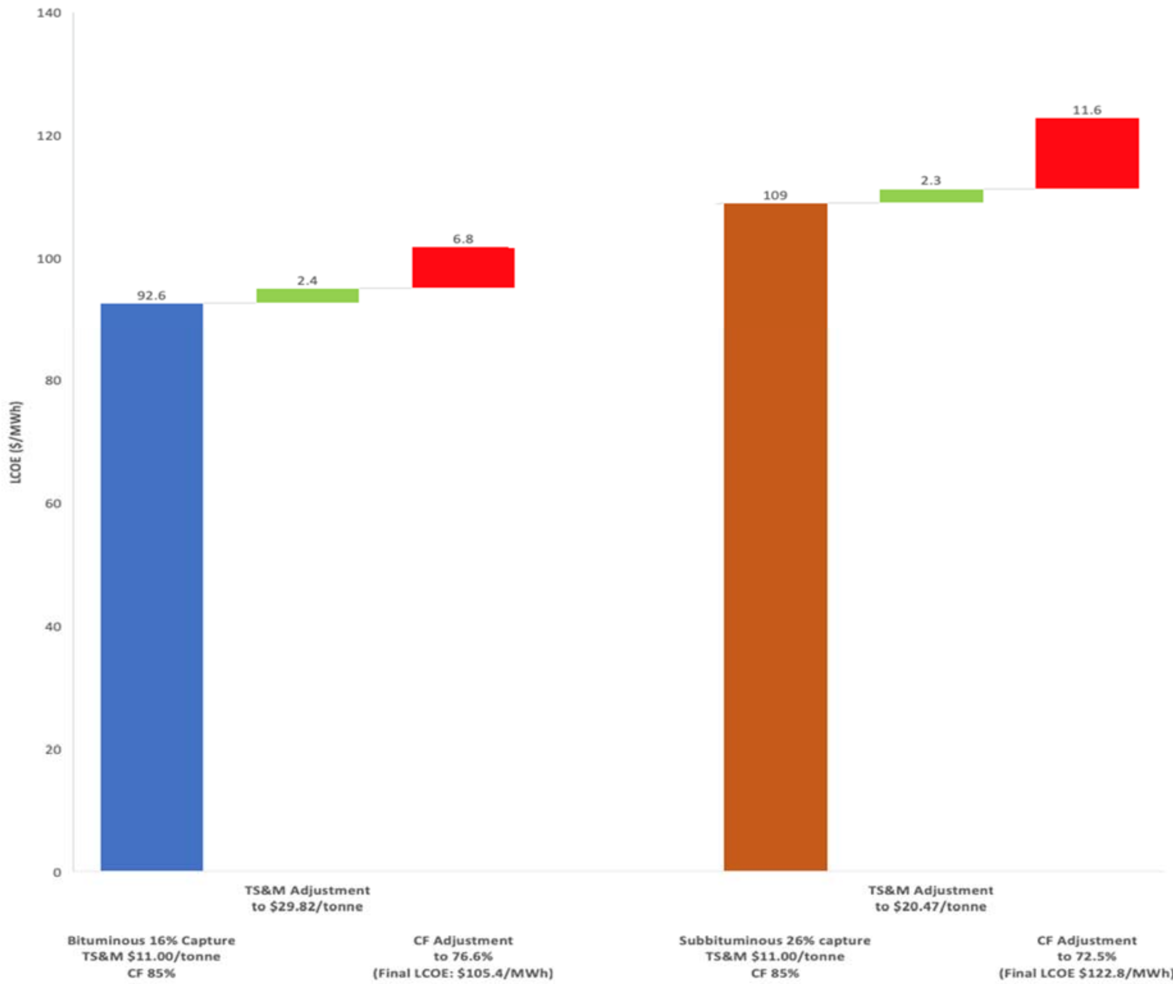
It is important to note that in a partial capture scenario, these costs still represent a small fraction of the LCOE of a coal plant with 16 percent CCS. The EPA spreadsheet used to support this Proposal shows that when the capacity factor of the coal plant is 85 percent, raising the T&S from $11/tonne changes the LCOE from $96.2/MWh to just $98.6/MWh, only a difference of $2.4/MWh or about 2.5 percent.[538] But even this small increase may overstate the cost of transporting and storing CO_2 from coal plants equipped with partial capture.

What drives the cost increase in EPA's Amended LCOE found in the Table 7 of the Proposal from the 2015 values is EPA's decision to reduce the capacity factor of CCS plants. EPA justifies this action because of increased T&S costs. The figure below shows the contributions of increasing the T&S and lowering the capacity factor to the LCOE used by EPA in part to justify this Proposal.

[537] EPA, *supra* note 534.

[538] EPA, CCS Costing Technical Support Document, Attach. 1: NETL Costs July 2015 Report Dec. 2018, Doc. ID: EPA-HQ-OAR-2013-0495-11950 (Dec. 21, 2019).

Figure 19: Contributions to Amended LCOE Calculated by EPA[539]



As detailed in the next section, this adjustment of the capacity factor is arbitrary and capricious.

The Agency must engage in "reasoned decisionmaking" and make choices "with adequate support in the record."[540] There is no support in the record for determining that a new plant would make choices against its economic interest considering the infrastructure available to it. While a range representing economies of scale may be useful to consider, basing the Proposal on the most unlikely scenario and nearly tripling the cost of transportation and storage is entirely unreasonable.

b. EPA's capacity factor adjustment is unreasonable.

EPA is proposing to account for the impact of the variable operating costs associated with partial-CCS on the unit's economic dispatch.[541] The Proposal concludes that "capacity factors for coal-fired

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539 CATF Analysis based on EPA, CCS Costing Technical Support Document, Attach. 1: NETL Costs July 2015 Report Dec. 2018, Doc. ID: EPA-HQ-OAR-2013-0495-11950 (Dec. 21, 2019).
540 *FERC*, 136 S.Ct. at 784.
541 83 Fed. Reg. at 65,438-39.

EGUs decrease approximately 1.5 percent for each $1/MWh increase in operating costs."[542] However, as EPA recognized in 2015, "[a] new fossil fuel-fired steam generating EGU would, most likely, be built to serve base load power demand and would not be expected to routinely start-up or shutdown or ramp its capacity factor in order to follow load demand."[543]

Put simply, a new coal plant is not economic under the current and foreseeable market conditions. If a utility decides that for purposes of fuel diversity, a new coal plant is desirable, it will be built in an area where it has anticipated paying a premium for that diversity and the plant will be utilized for baseload generation. EPA fails to provide any rationale based in the realities of the current market and unreasonably reduced the capacity factor for a new plant from 85 percent to 76.6 percent for a bituminous coal plant and 72.5 percent for a low-rank coal plant.[544] This adjustment is arbitrary and capricious.

6. Taking into account revenue and incentives and correcting EPA's flawed cost inflation, the cost of *full*-CCS is reasonable even without expected future cost declines.

In 2015, EPA found that at that time, the costs of full capture were predicted to be significantly more costly than partial-CCS or other non-gas baseload technology and therefore did not finalize a standard based on full capture.[545] Since EPA's 2015 findings, however, conditions have changed, and CCS is more economical than demonstrated by the previous record. As noted *supra*, costs for the next projects are projected to be at least 30 percent less expensive than the current ones, and in 2018, significant modifications to 45Q CO_2 storage tax credits became law and made CCS far more economic. These changes, along with the availability of EOR and existing 48A investment tax credits for CCS reduce *full* capture costs to levels consistent with 16 percent capture and uncontrolled coal.

The figure below shows the impact of 45Q and 48A tax credits on the LCOE for various levels of CCS on SCPC plants burning bituminous coal. The values in this figure were developed using EPA's assumed costs in this Proposal.[546] As conservative reference points, the figure includes red and green comparison lines. The red line corresponds to EPA's cost estimate of SCPC with 16 percent capture on bituminous coal *before* adjustments were made.[547] The green line shows EPA's cost estimate of a new *uncontrolled* SCPC with no CCS on bituminous coal.[548] To be conservative, the vertical bars in the figure do not include cost reductions due to technology improvements described *supra*. Including these cost reductions would lower the LCOE even further.

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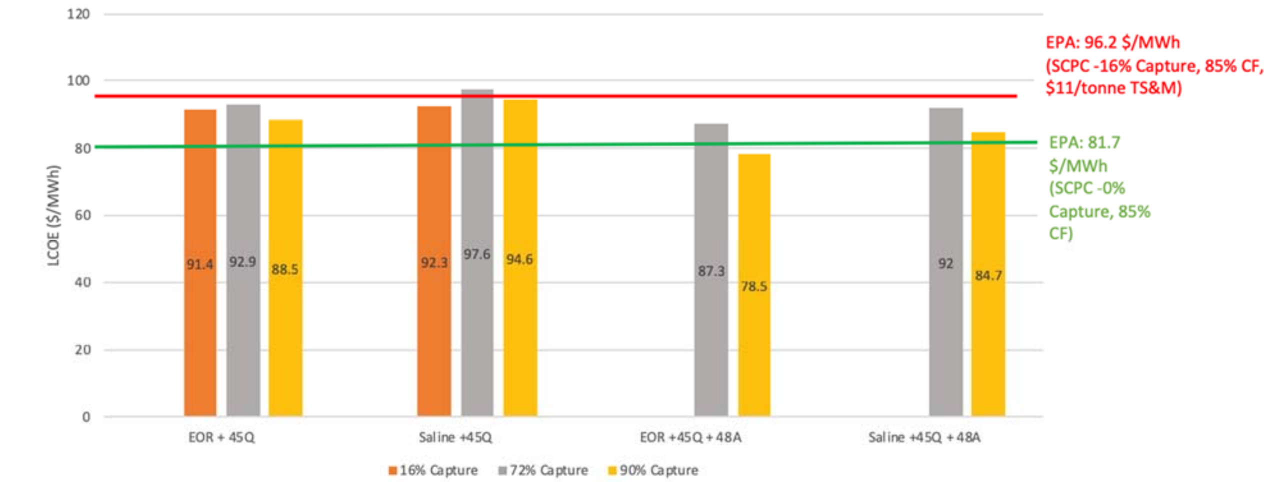
542 *Id*. at 65,438.
543 80 Fed. Reg. at 64,573.
544 83 Fed. Reg. at 65,439.
545 80 Fed. Reg. at 64,548.
546 EPA reports in 83 Fed. Reg. at 65,439-40 tbl. 8 its LCOE for SCPC plants. Table 8 is based on calculations EPA performed found in EPA, CCS Costing Technical Support Document, Attach. 1: NETL Costs July 2015 Report Dec. 2018, Doc. ID: EPA-HQ-OAR-2013-0495-11950 (Dec. 21, 2019). Figure 20 uses this data and includes 45Q revenue and $22/tonne EOR revenue from that spreadsheet as well. The modified spreadsheet is at Appendix C.
547 83 Fed. Reg. at 65,439 tbl. 7.
548 *Id*.

Figure 20: Electricity Cost of New SCPC Bituminous Plants with CCS Utilizing Tax Incentives



As this figure shows, tax credits significantly reduce the LCOE to a point that *full*-CCS is comparable to partial-CCS and even *uncontrolled* plants. 45Q provides tax credits of $35/tonne for EOR and $50/tonne for saline storage for a period of 12 years. During this 12-year period the impact on CCS economics is substantial, especially at higher rates of capture where more tonnes of CO_2 lead to higher revenues. With EOR revenues of $22/tonne and 45Q revenues of $35/tonne, the LCOE with 90 percent capture is $88.50/MWh or $2.90/MWh lower than 16 percent capture that also earn the 45Q credit. Similarly, an uncontrolled SCPC plant with saline storage and 90 percent capture has an LCOE of $94.60/MWh which is similar to but higher than 16 percent capture LCOE of $92.30/MWh. In all cases, 45Q lowers the cost of 16 percent capture and 90 percent capture to below the EPA's calculated costs of $96.2/MWh for a 16 percent capture plant without 45Q operated at 85 percent capacity factor and TS&M costs of $11 per tonne.

When 48A tax credits are included with 45Q, the LCOE of 90 percent capture plants are below or comparable to EPA's LCOE cost of a new uncontrolled coal plant.[549] While these costs are still higher than both an uncontrolled gas plant and a gas plant with 90 percent capture, those rare cases where a utility considers a new coal plant for non-economic reasons would consider these tax credits important in comparing the economics of coal and uncontrolled coal plants.

As described above, utilities are primarily building new gas plants and renewable energy but in the rare circumstances where for non-economic, fuel diversity reasons, a utility chooses to build a new coal plant, it must hedge against the likely decarbonized future and control carbon to the maximum feasible extent.

Full capture CCS coal plants better meet these objectives because the CO_2 emissions profile is significantly lower than uncontrolled coal plants, a plant designed with 90 percent capture can achieve 95 percent capture at lower capacity factors that result from the load following needed to back-up renewables, a coal plant with 90 percent capture is less at risk to future carbon taxes or future climate policies that could strand an uncontrolled coal asset, and the availability of 45Q and

[549] 48A tax credits are only available to plants which capture at least 65% of their CO_2 emissions. 26 U.S.C. § 48A(e)(1)(G).

48A tax credits would eliminate or virtually eliminate the LCOE difference between a full capture plant and one without controls.

For these reasons, and the documentation found throughout these comments, EPA must establish full capture as the best system of emission reduction for coal-fired power plants. While the record still should recognize the value of partial capture, new conditions since 2015 warrant a decision to establish 90 percent capture as the best system.

7. BACT determinations are irrelevant to this rulemaking.

The best available control technology (BACT) determinations made during the permitting processes for individual permits for major emitting facilities are made by states based on an entirely different statutory criteria than the nationally applicable performance standards at issue here. Disregarding these important differences, in this Proposal, EPA reviewed the permits for various facilities – none of which were in the relevant source category - between 2011 and 2017, where all but one rejected *full*-CCS as the BACT under the Prevention of Significant Deterioration (PSD) program.[550] EPA mistakenly takes this as evidence that CCS is not an appropriate best system of emission reduction under the entirely separate section 111 program.[551]

However, in 2015, EPA explained in great detail, why the BACT determinations under section 165 of the Clean Air Act are irrelevant for the purposes of determining the best system of emission reduction under section 111.[552] First, no greenhouse gas BACT determination has been made for a unit that would be subject to this rulemaking.[553] Second, PSD permitting requirements for greenhouse gases only began in January 2011 and therefore experience and information will develop significantly over the regulatory period. Almost all of the permits that EPA reviewed are five to eight years old. Yet, section 111 is a technology-forcing, forward-looking section, and as described above, CCS has made significant advancements in the past five years, which will be built upon over the relevant regulatory period. The one relatively recent permit – the Irvington Generating Station from 2017 – is a conversion from coal to gas with a 1,100 lbs. CO_2/MWh limit, which is well below the current NSPS.[554] Third, the agencies were evaluating full-CCS, not partial-CCS – the best system currently applicable here. Even so, the agencies found full-CCS technically feasible because the determinations were not made at step 2 of the BACT analysis (eliminate all technically infeasible options). Finally, it is generally the state agency that makes the BACT determinations, and while EPA provides oversight, approving the permit does not necessarily imply endorsement of the determination.[555] On the other hand, section 111 best system determinations are exclusively within the purview of the Administrator.[556]

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550 83 Fed. Reg. at 65,441; EPA, Review of BACT Determinations for GHG Emissions, Doc. ID: EPA-HQ-OAR-2013-0495-11951 (Dec. 2018).
551 83 Fed. Reg. at 65,441.
552 *See generally* 80 Fed. Reg. at 64,630-32.
553 *Id.* at 64,631-32.
554 Pima Cty. Dep't of Envtl. Quality, *Technical Support Document: Tucson Electric Power (TEP) – Irvington Generating Station*, at 15 tbl. 4 (Aug. 2018), http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/AQ%20Operating%20Permits/All%20Current%20Permits/Class%20I/1052/EX4.pdf.
555 80 Fed. Reg. at 64,632.
556 42 U.S.C. § 7411(a)(1).

Regardless, one of the permits EPA reviewed *did* determine that BACT was 35 percent CCS.[557] Five years ago, in November 2014, EPA Region 6 issued the permit to the Ramsey Gas Plant – a natural gas processing facility in Orla, Reeves County, Texas. EPA determined that "[c]apturing and transporting high-purity CO_2 from Amine Still Unit Vents, with the CO_2 destined for EOR, has been proven and is occurring elsewhere."[558]

EPA fails to overcome its previous decision that these permit decisions are of limited applicability to this rulemaking.

D. The current standards reduce emissions.

As the Agency recognizes in the Proposal,[559] in determining the best system EPA must consider the amount of emissions reductions achieved through application of the system.[560] In 2015, EPA performed a comprehensive investigation into the impact of greenhouse gas emissions and found that the burning fossil fuels is having devastating impacts on the climate and in turn "threaten[ing] the health of Americans in multiple ways."[561] The Agency therefore appropriately took the urgency of climate change and the impact of emissions from coal-fired power plants into account when determining the best system to reduce CO_2 emissions.

EPA concluded that "[t]he final standard of performance will result in meaningful and significant emission reductions of GHG emissions from new coal-fired steam generating units."[562] Finding that a highly efficient 500 MW coal plant with partial-CCS would emit 675,000 fewer metric tons of CO_2 per year than a new less efficient coal plant with an emission rate of 1,800 lbs. CO_2/MWh-g.[563] Note that in 2015 EPA assumed that a less efficient coal plant under a business as usual scenario would have a lower emission rate than the rate the Agency now proposes as reflecting the *best* system of emission reduction. EPA's analysis demonstrated that the climate and human health benefits would outweigh regulatory costs under a range of assumptions.[564]

In 2015, EPA also calculated the combined CO_2-related and $PM_{2.5}$-related benefits from a coal plant meeting the 1,400 lbs. CO_2/MWh-g standard, as compared to a new non-compliant coal plant, which the Agency assumed would emit 1,700 lbs. CO_2/MWh-n.[565] The Agency concluded that the rule would provide a health and climate benefit of $18 for every MWh generated.[566] Therefore, for

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557 EPA, *Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Nuevo Midstream, LLC, Reeves County, Texas*, at 25 (Oct. 2014), https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/nuevo-midstream-ramsey-sob100714.pdf.
558 *Id.* at 20.
559 83 Fed. Reg. at 65,433.
560 *See Sierra Club*, 657 F.2d at 326 ("[W]e can think of no sensible interpretation of the statutory words 'best . . . system' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions.").
561 80 Fed. Reg. at 64,517-25; *see also* 2015 RIA at 3-1 to 3-7.
562 80 Fed. Reg. at 64,574.
563 *Id.*
564 2015 RIA, ch. 5; *see also* Br. of *Amicus Curiae* Inst. for Policy Integrity at N.Y.U. School of Law in Supp. of Resp'ts, *North Dakota v. EPA*, 15-1381, Doc. No. 1652433 (D.C. Cir. Dec. 21, 2016) (Attach. K).
565 2015 RIA, at tbls. 5-1 & 5-3.
566 2015 RIA, at tbl. 5-3.

EPA's hypothetical new 600 MW coal-fired plant, *every single hour* it operated would impose $10,800 of harm on the public, piling up to $75,686,400 per year if the plant ran at 80 percent capacity.

Unfortunately, the Proposal entirely neglects the statutory directive to consider emission reductions – proposing a standard which is not only significantly worse than the current standard, but also worse than business as usual. Despite the daunting record EPA compiled in 2015, the Proposal fails to even mention the words "climate change." Meanwhile, the dangers of climate change have only intensified,[567] and the electric power sector is responsible for 33 percent of all U.S. CO_2 emissions.[568]

In the Economic Impact Analysis for this Proposal, the Agency acknowledges that greenhouse gases "may reasonably be anticipated both to endanger public health and to endanger public welfare" and that one new plant would emit 1.1 million more tons of CO_2 per year under the Proposal,[569] but inexplicably, the Agency does "not attempt to quantify the impacts of these increased emissions or economic value of these impacts."[570] The Agency also admits that the Proposal will "influence the level of emissions of certain pollutants in the atmosphere that adversely affect human health," increasing the emissions from one new plant by 500 tons per year of SO_2, a precursor to $PM_{2.5}$.[571] Again, inexplicably, EPA does "not attempt to quantify the number or economic value of these air pollution-related effects."[572] EPA must, however, consider collateral impacts in determining which technology is "best" under section 111.[573] EPA "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[574]

While companies are already choosing to build lower-emitting generation sources, market forces are no substitute for proper regulation. EPA admits as much when it stresses that "future realizations could deviate from … expectations as a result of changes in wholesale electricity markets, [and] federal policy intervention …."[575] A stringent emission standard will lock in a lower-carbon future and ensure continued progress. Moreover, aggregate emissions from natural gas plants are increasing, and it will be necessary to retrofit these units with carbon capture equipment to limit catastrophic climate change. Basing the standard on CCS will provide a regulatory driver for continued innovation and cost declines – factors that EPA *must* take into account.[576]

The proposed standard, if finalized, would be arbitrary and capricious because EPA failed to consider an important aspect of the problem: the significant harms from increased CO_2 emissions and other health-harming air pollutants.[577] EPA's standard, which is higher than an uncontrolled coal

[567] *See, e.g.*, U.S. Glob. Change Research Program, *Fourth National Climate Assessment*, *Vol. II: Impacts, Risks, and Adaptation in the United States* (Nov. 2018), https://nca2018.globalchange.gov/.
[568] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017*, at tbl. ES-2 (Feb. 12, 2019), https://www.epa.gov/sites/production/files/2019-02/documents/us-ghg-inventory-2019-main-text.pdf.
[569] 2018 EIA, at 2-4, tbl. 2-1.
[570] 2018 EIA, at 2-6.
[571] 2018 EIA, at 2-4, tbl. 2-1.
[572] 2018 EIA, 2-7.
[573] *See Portland Cement*, 486 F.2d at 386; *Essex Chemical Corp.*, 486 F.2d at 439.
[574] *Ctr. for Biological Diversity*, 538 F.3d at 1198.
[575] 83 Fed. Reg. at 65,427.
[576] *Sierra Club*, 657 F.2d at 347.
[577] *State Farm*, 463 U.S. at 43.

plant currently operating, is entirely contrary to the language and purpose of the Clean Air Act and plainly unlawful.[578] A system cannot be "best" if it does more harm than good.[579]

E. The current standard is achievable.

As we demonstrate above, CCS is "adequately demonstrated," however it not CCS, but "the *standard* which must be achievable. This does not require that a … plant be currently in operation which can at all times and under all circumstances meet the standards."[580] In 2015, EPA found the 1,400 lbs. CO_2/MWh-g standard "to be achievable over a wide range of variable conditions that are reasonably likely to occur" when the system is properly designed and operated as required by *National Lime*, including across different coal types and operation during startup and shutdown.[581] Compliance with the standard is demonstrated over a very forgiving 12-month operating average, which allows for short-term excursions associated with operational fluctuations, start-ups, shutdowns and malfunctions.[582] Furthermore, while most large-scale CCS projects can capture upwards of 90 percent of emissions, the best system of emission reduction here is based on 16-23 percent capture.[583]

But even more importantly, as described throughout these comments, while the best system of emission reduction underlying the standard is post-combustion CCS with saline storage, multiple compliance pathways are available, some of which do not even involve sequestration. Plants can co-fire with about 40 percent gas to meet the standard, build an IGCC plant, or install CCS. If a plant installs CCS, it can utilize post-combustion capture, pre-combustion capture, or oxy-combustion capture. It can have an integrated design like Boundary Dam, or a separate plant can power the carbon capture system like Petra Nova. The CO_2 can be sequestered in saline, coal seams, or at enhanced oil recovery operations. The plant can be built near sequestration opportunities and use transmission lines to reach customers, near customers and utilize pipelines to access sequestration, or most likely, a combination of the two.

The experiences at Boundary Dam and Petra Nova, as described above, demonstrate that the standard is flexible enough to be achieved, even if issues arise. EPA designed a standard that could accommodate the initial operational hiccups associated with early operation.[584]

Instead of proposing a standard which is achievable over a wide range of conditions *likely to recur*, EPA dismisses any standard that cannot be achieved everywhere under the most unlikely conditions that almost certainly *will not occur*. EPA explicitly rejected this approach, which a commenter suggested in 2015, stating that "[t]he commenter is mistaken as a matter of law that a BSER must be

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578 *Sierra Club*, 657 F.2d at 326 ("Control technologies cannot be 'best' if they create greater problems than they solve. In fact, we do not see how we could uphold a variable standard if EPA had not evaluated its effect on air emissions.").
579 *Portland Cement*, 486 F.2d at 384; *Essex Chem. Corp.*, 486 F.2d at 439.
580 *Essex Chem. Corp*, 486 F.2d at 433 (emphasis added).
581 80 Fed. Reg. at 64,573; *see also id.* at 64,540 & n.153 (citing *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46); EPA, Achievability of the Standard for Newly Constructed Steam Generating Units, Doc. ID: EPA-HQ-OAR-2013-0495-11771 (July 31, 2015).
582 80 Fed. Reg. at 64,573; EPA, Achievability of the Standard for Newly Constructed Steam Generating Units, Doc. ID: EPA-HQ-OAR-2013-0495-11771 (July 31, 2015).
583 *See* 80 Fed. Reg. at 64,513.
584 Denial of Reconsideration, at 12.

deployed on all operating sources, which would indeed defeat the whole purpose of a new source standard which is to reflect best system of emission reduction, not some type of least common denominator."[585]

After considering the legislative history of the Clean Air Act, and section 111(b) in particular, caselaw and longstanding Agency precedent, EPA determined that "an emissions standard may meet the requirements of a 'standard of performance' even if it cannot be met by every new source in the source category in the absence of that standard."[586] In enacting section 111, Congress was explicit that uniform, national standards would require power plants to be "controlled to the maximum practicable degree *regardless of location*."[587] These uniform standards would work toward avoiding pollution havens, however, due to attainment provisions, Congress recognized that there may be places where a new emission sources cannot be built.[588]

Courts have a long history of upholding standards that certain sources or classes of sources cannot meet, so long as the standards allow the industry, as a whole, to continue to meet demand.[589] EPA explained that "[b]y the same token, the inability of some coal-fired sources to locate in certain areas would not create reliability problems or prevent the satisfaction of overall demand for electricity."[590] It has been EPA's long-held position that "section 111 authorizes a standard of performance for a source category that may not be feasible for all types of new sources in the category, as long as there are other types of sources in the category that can serve the same function and meet the standard."[591]

This Proposal, however, with its insistence that a plant with the most unlikely combination of factors is accommodated is at odds with legislative history, caselaw and precedent and fails to provide "good reasons" for the change or even "display awareness that it *is* changing position. An Agency may not …depart from a prior policy *sub silentio*…"[592]

The Proposal fails to recognize that the 1,400 lbs. CO_2/MWh-g standard can be achieved through a variety of measures for any plant that could be build and further makes a legal error in asserting that a standard must be achievable for all sources. The legal error is compounded by the fact that the Proposal does not defend its change in position. These cascading errors render the Proposal arbitrary, capricious and unlawful.

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585 EPA, Response to Comments, Standards for Fossil Fuel-fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-225, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).
586 80 Fed. Reg. at 64,540 (citing 79 Fed. Reg. 1430, 1466).
587 79 Fed. Reg. at 1466 (citing S. Rep. 91-1116, at 16 (1970)).
588 *Id.* at 1466-67 (citing 1970 S. Comm. Rep., at 2, and 116 Cong. Rec. 32,917 (1970)).
589 *See Int'l Harvester Co. v. Ruckelshaus*, 478 F.2d. 615, 640 (1973) (finding that automobile emission standards are permissible so long as demand for automobiles is met, even if it has the effect of banning less efficient automobiles); *Weyerhaeuser*, 590 F.2d at 1054 (D.C. Cir. 1978) (upholding EPA effluent limitations that were more difficult for some mills to meet); *see also NRDC v. EPA*, 489 F.3d 1364, 1372 (D.C. Cir 2007) (holding that EPA is not required to create a separate subcategory to accommodate a particular type of source for which control technology is more costly).
590 79 Fed. Reg. at 1467.
591 *Id.* (citing 41 Fed. Reg. 2331, 2333 (Jan. 15, 1976), which set uniform standards for smelters even though the costs for one type of smelter was unreasonable when the Agency found that other smelters could accommodate demand).
592 *Fox Television Stations*, 556 U.S. at 515.

F. CCS will not result in increased water consumption.

In 2015, EPA looked closely at the water impacts associated with CCS operation. The Agency found water use to be manageable and decreasing in magnitude.[593] The studies raising concerns with increased water use consider 90 percent capture or greater, not the 16-23 percent best system here. EPA found that CCS would increase water usage merely 6.4 percent, noting that it is common that *any* air pollution controls increase consumption of water.[594] Further, the Agency recognized that efforts are ongoing to minimize water usage at CCS facilities, pointing to Boundary Dam, which collects water from the coal and combustion process and recycles the captures water.[595] EPA also notes that in areas with severe water constraints, the plant could build an IGCC or co-fire with natural gas.

This Proposal contends that the 2015 analysis did not adequately consider the combined impacts of water availability and increased water consumption required for carbon capture.[596] EPA states, "[a]ll CCS systems that are currently available require substantial amounts of water to operate. These water requirements would limit the geographic availability of potential future EGU construction to areas of the country with sufficient water resources."[597] As described below, this statement is false, and EPA cannot use it as a basis for concluding that CCS in not available.

EPA incorrectly concludes that low-rank coal plant with 26 percent CO_2 capture must increases water consumption

Although carbon capture increases heat rejection requirements at a coal plant, that does not necessarily mean that water consumption must go up at the plant to meet these cooling needs. The impact of carbon capture on water consumption depends on the type of cooling selected by the developer. There are three options for cooling coal and natural gas-fired power plants:[598]

> 1. Dry cooling (also called air cooling): Dry cooling systems reject heat in the plant's hot water directly to the atmosphere using air-cooled condensers (ACCs). These systems do not consume cooling water.
>
> 2. Wet cooling: A wet cooling tower cools hot water and recirculates it to a condenser. Cooling towers can be natural-draft or mechanical-draft.
>
> 3. Hybrid cooling: Hybrid cooling combines both the wet and dry cooling approaches. Generally, the plant uses dry cooling during cooler weather and wet cooling during hot periods when dry cooling systems are less effective.

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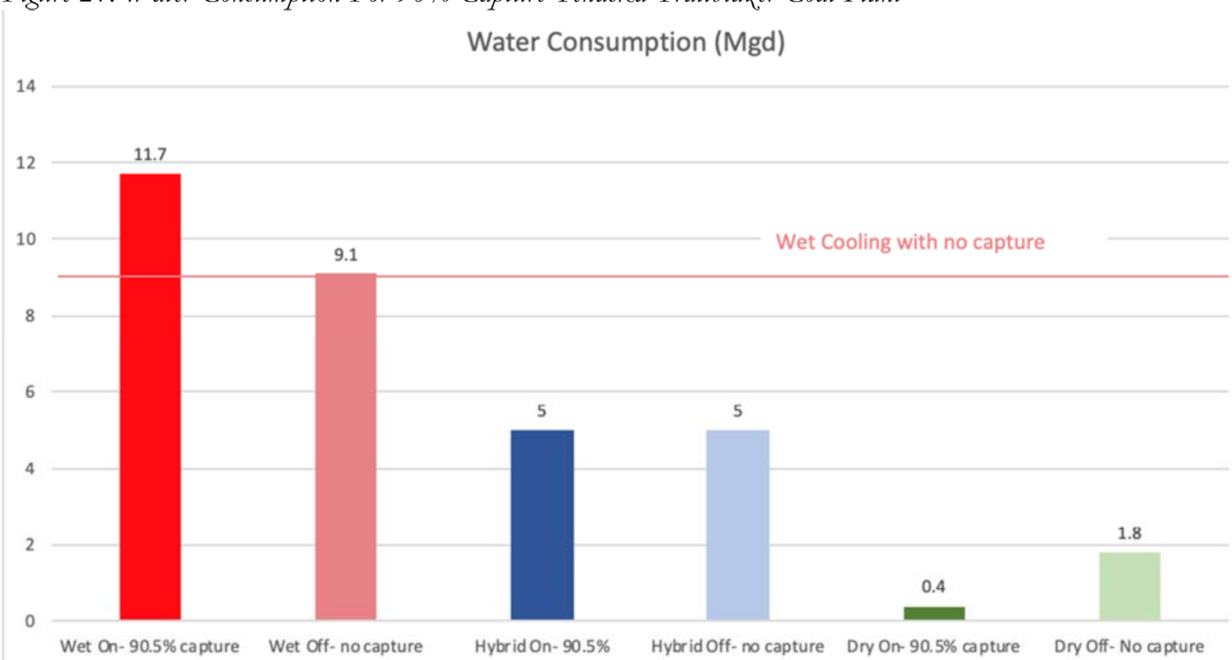
[593] 80 Fed. Reg. at 64,592; EPA, Response to Comments, Cost and Benefits, at 3-54, Doc. ID: EPA-HQ-OAR-2013-0495-11862 (Oct. 23, 2015).
[594] 80 Fed. Reg. at 64,592.
[595] *Id.*
[596] 83 Fed. Reg. at 65,443-44.
[597] *Id.* at 65,443.
[598] John Maulbetsch, *Evaluating the Economics of Alternative Cooling Technologies*, POWER ENGINEERING (Nov. 1, 2012), https://www.power-eng.com/articles/print/volume-116/issue-11/features/evaluat-economics-alternative-cool-technologies.html.

These three cooling options were detailed in a carbon capture context by the first proposed new coal plant with 90 percent capture to receive an air permit – Tenaksa's 600 MW-n Trailblazer plant, which was to be located in Sweetwater, Texas.[599] The Trailblazer plant location had easy access to EOR fields and rail access for sub-bituminous low-rank coal but the site was water constrained. As part of the development process, the Global CCS Institute funded Tenaska to prepare a report that documented their cooling technology options and selection for the project.[600] Tenaska examined three options: wet cooling, hybrid cooling and dry cooling. For each configuration, they examined water consumption when the capture unit was turned on (capturing 90.5 percent of the plant's CO_2) and when the capture unit was off (no capture). The figure below summarizes in millions of gallons per day of water the average water consumption findings from the report:

Figure 21: Water Consumption For 90% Capture Tenaska Trailblazer Coal Plant[601]



As the figure shows, wet cooling requires the most water consumption. Using carbon capture increases the water consumption requirements by 29 percent on an average basis, although the range for this plant varied from 25-40 percent depending on ambient temperature conditions.[602] Dry cooling requires the least amount of water. Compared to the wet cooling, dry cooling reduces water consumption by over 96 percent. The Tenaska's report noted an important fact about carbon capture when using dry cooling, "the CC [carbon capture] Plant *decreases* water consumption by 40 – 80 percent which equals 0.8 to 1.4 mgd (3,028 – 5,300 m3/d) depending on the ambient condition.

599 The plant was issued an air permit by the Texas Commission on Environmental Quality on December 30, 2010. EPA, *TX-0585*, RACT/BACT/LAER CLEARINGHOUSE (Sept. 14, 2011), https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.FacilityInfo&facility_id=27221.

600 Tenaska Trailblazer Partners, LLC, *Cooling Alternatives Evaluation for a New Pulverized Coal Power Plant with Carbon Capture* (Aug. 2011), http://decarboni.se/sites/default/files/publications/24367/cooling-study-report-2011-09-06-final-w-attachments.pdf.

601 *Id.* at 21.

602 *Id.*

This is because the CC Plant includes an upfront cooling step that condenses combustion water vapor which is re-used in the PC Plant."[603] The hybrid case, which combines dry and wet cooling, reduced water consumption by more than half compared to the wet-cooled carbon capture case. Significantly, regardless of whether carbon capture was turned on or off, hybrid cooling consumed the same amount of water. Again, the condensed water from the carbon capture plant was sufficient to offset cooling requirement of carbon capture because the hybrid approach includes some dry cooling.

This finding that hybrid cooling does not lead to increased water consumption was affirmed by a recent feasibility study on SaskPower's Shand Plant.[604] The 305 MW Shand Plant burns low-rank lignite and is located in a water constrained area. Using hybrid cooling, the feasibility found, "The only new water used in the system is the water that is condensed out of the unit's flue gas. The use of a hybrid cooling system with dry coolers and wet surface air coolers … has the potential to be a reasonable first approach to cooling at any coal-fired power plant and is especially effective with high moisture low-rank coals."[605]

In contrast to these studies, EPA concluded that a coal plant burning low-rank coal in an SCPC plant configured with spray dryer and fabric filter would consume 3.8 gpm/MW-n without CCS and 4.9 gpm/MW-n, a 28 percent increase in water consumption.[606]

The water consumption value of 3.8 gpm/MW-n used by EPA comes from the NETL low-rank coal baseline study. The SCPC base plant in the NETL report uses hybrid cooling. As discussed in the report, "The largest consumer of raw water in all cases is cooling tower makeup. Since plants located in the Western U.S. need to consider limited water supplies, a parallel wet/dry condenser was chosen for all plant configurations similar to the system being installed at the currently under construction Comanche 3 plant. In a parallel cooling system, half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser."[607]

To obtain the quantity of water consumed with partial capture on the low-rank coal SCPC plant, EPA calculates the water consumption based on the 2015 NETL partial capture sensitivity on SCPC using bituminous coal.[608] EPA justifies this method because "the absolute amount of water required for CO_2 capture equipment is relatively constant on a gallon per ton of captured CO_2 basis across various boiler types."[609] What EPA overlooks however, is that the cooling method used in the NETL bituminous coal study relies on wet cooling[610] not the hybrid cooling system used in NETL's low-rank coal study.

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[603] *Id.*
[604] Int'l CCS Knowledge Ctr., *supra* note 112.
[605] *Id.* at 12.
[606] 80 Fed. Reg. at 65,443.
[607] *See* NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 3b: Low-rank Coal to Electricity: Combustion Cases, at 31, Doc. ID: EPA-HQ-OAR-2013-0495-11790 (Mar. 2011). However, the capture studied in this report uses wet cooling. *Id.* at 7.
[608] 83 Fed. Reg. at 65,443.
[609] *Id.*
[610] The partial capture sensitivity is based on the data developed for NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, Doc. ID: EPA-HQ-OAR-2013-0495-11341 (July 6, 2015). As noted, this report is based on wet cooling. *See id.* at 74.

As a result of the cooling choice embedded in EPA's methodology - hybrid cooling for the low-rank SCPC plant but wet cooling for any CO_2 capture - EPA erroneously concludes that an SCPC plus 26 percent CCS must lead to a 28 percent increase in water consumption. This conclusion is wrong. In a water constrained area where a new coal plant developer opts for hybrid cooling to limit water consumption, the decision to include CCS will not result in any increase in water consumption, up to and including full capture. CCS will not result in any need to increase the water allotment for the plant because the carbon capture unit will condense water from the flue gas, and this additional water is sufficient to address additional cooling needs resulting from capture when hybrid cooling is selected.

Hybrid Cooling and Dry Cooling Systems are Available for Coal Plant Equipped with Carbon Capture

EPA states, "Carbon capture technologies are limited to using conventional wet cooling technologies."[611] This statement is false. The Shand Plant carbon capture feasibility study is based on hybrid cooling because it is available for the SaskPower's plant. Furthermore, the choice contributes to the overall favorable economics of the project. The feasibility study concludes that the cost of capture at Shand would be $45/tonne in U.S. dollars.[612]

Tenaska found that both hybrid and dry cooling technology were available for their project. The engineering company hired by Tenaska to develop the design and cost for the project was Fluor. Fluor is the company that owns the Ecoamine carbon capture technology proposed for Trailblazer and which is the basis for the 2011 NETL low-rank carbon capture study. As Tenasksa notes, "Fluor has determined that it is feasible to air cool the CC Plant Econamine FG+ technology and achieve the desired CO_2 capture rate at the Trailblazer site ambient conditions."[613] Dry cooling was also economic. Tenaska concluded that dry cooling was the lowest cost option for the Trailblazer plant.[614]

While the Trailblazer project was canceled because it was predicated on climate legislation that did not become law, the issued air permit and studies must be relied upon by EPA as demonstration that dry cooling is available for plants with CCS.[615]

Taken together - the erroneous conclusion that carbon capture on low-rank coal plants must always increase water use and the Agency's erroneous conclusion that carbon capture is limited to wet cooling options - the EPA must conclude that water availability is not a factor in determining whether CCS is the best system of emission reduction for new coal plants.

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[611] 83 Fed. Reg. at 65,443.
[612] Int'l CCS Knowledge Ctr., *supra* note 112, at iii, x, 78.
[613] Tenaska Trailblazer Partners, LLC, *supra* note 600, at 22.
[614] *Id.* at 6. After the initial design work was completed, Tenaska received bids for the dry cooling option. These bids were higher than expected. The result of the competitive bidding process for the air coolers was higher costs than were previously estimated. In addition, the final design included raising the height of the air coolers and including a lower design air velocity with an increased fin spacing. A 20 percent spare heat transfer surface area was included in the design basis, but variable frequency drives or two-speed fans were not considered. Had these impacts been known at the point in time when the cooling study was completed, the hybrid cooling option may have provided the lower evaluated cost (although its cost may have been affected somewhat similarly). Even so, with the lack of water available for the Project in semi-arid West Texas, there is a high probability that dry cooling still would be a necessity." *Id.* at 25.
[615] *Essex Chem. Corp.*, 486 F.2d at 434 (upholding standards based on literature review).

IV. Co-firing is available and can be used to meet current standard.

The potential to significantly reduce the carbon pollution from steam boilers by using natural gas in lieu of coal is well demonstrated and should be recognized in EPA's determination of the best system of emission reduction. In 2015, EPA noted that, although the Agency determined that partial-CCS is the best system of emission reduction for new coal-fired power plants, "operators can consider the use of natural gas co-firing to achieve the final emission limitation, likely at a lower cost."[616] EPA concluded that "[a]t the final emissions limitation of 1,400 lbs. CO_2/MWh-g a new supercritical PC or supercritical CFB can meet the standard by co-firing with natural gas at levels up to approximately 40 percent (heat input basis) and could potentially avoid (or delay) installation and use of partial-CCS altogether."[617] This Proposal fails to justify EPA's choice to ignore the availability of co-firing either to meet the current standard or serve as the best system of emission reduction itself; EPA's failure is particularly inexcusable given that the emission reductions achievable at low-cost through the use of co-firing are far greater than the reductions expected from the proposed "best system."

A. Co-firing is already widely used, and EPA has sufficient information to analyze its impacts.

The Proposal makes the absurd claim that "at this time, the EPA does not have sufficient information to analyze the overall impact of co-firing natural gas, particularly impacts on dispatch."[618] This is simply not true. EPA reviewed numerous co-firing-related studies for the 2015 rulemaking,[619] and observed that "[n]atural gas co-firing has long been recognized as an option for coal-fired boilers to reduce emissions."[620] This Proposal barely even acknowledges that existing record and ignores data that have become available since the 2015 rulemaking.

Co-firing is a common practice in the U.S.: 399 coal units currently co-fire with natural gas (see Appendix D). These co-fired units represent 53.5 GW of capacity (or 21.7 percent of the current operating fleet).[621] The quantity of gas burned varies significantly between different co-firing units depending on the modifications and configurations used at each individual boiler. As shown in the figure below, a sample of U.S. co-fired units demonstrates that operators routinely co-fire gas at 50 percent or more on a monthly basis. Several units have maintained 100 percent gas for a month or longer.

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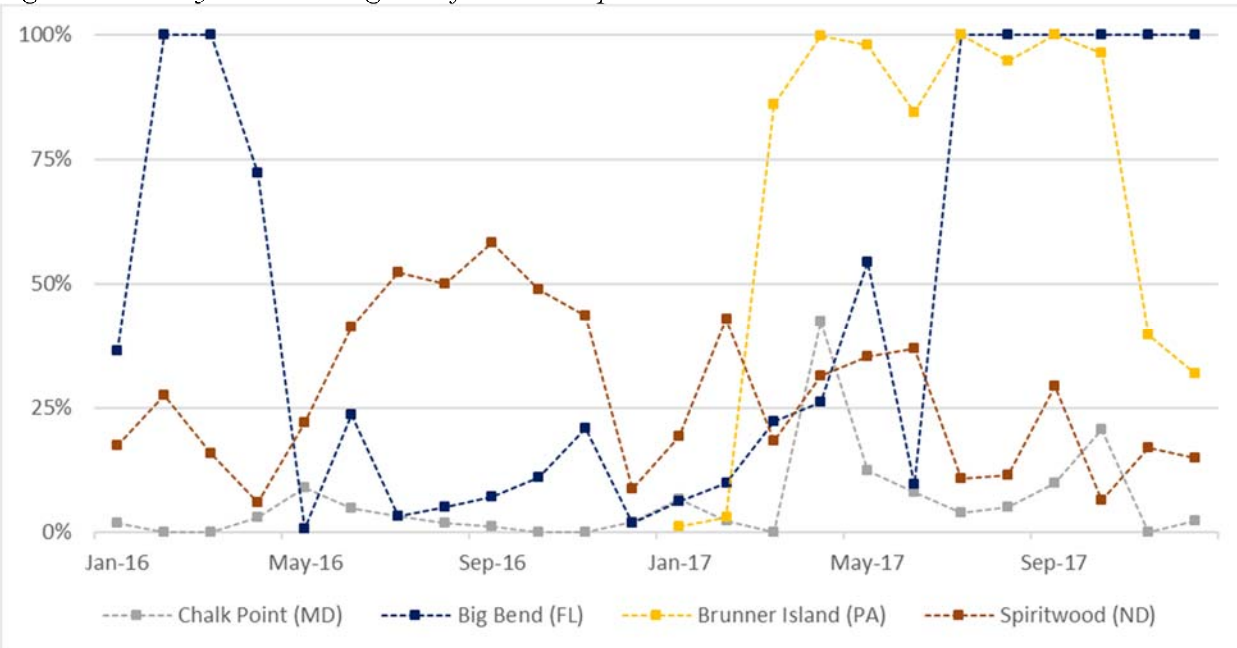
616 80 Fed. Reg. at 64,564.
617 *Id.*
618 83 Fed. Reg. at 65,445-46.
619 *See, e.g.*, 80 Fed. Reg. at 64,564-65 nn. 288-92.
620 *Id.* at 64,564.
621 EIA, *Electric Power Monthly: Table 6.2.C: Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, July 2018 and 2017* (Sept. 2018), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_02_c.

Figure 22. Monthly Gas Co-Firing Rates for Four Sample Units



Adding natural gas co-firing to coal plants "offers utilities the possibility of rapid response to changes in load demand and deep cycling capability."[622] Coal-fired power plants cycle up to full load very slowly – it may take a supercritical unit 12 hours or longer to ramp up from a cold start to full load – but the ability to switch to gas at low loads and switch back to coal at high loads offers a competitive advantage.[623] Co-firing with natural gas reduces warm-up times, allowing a unit to be brought online faster and helping coal-fired boilers reduce their minimum operating threshold. This can make coal-fired units more competitive and cost-effective by reducing cycling costs and allowing for more flexible economics in response to market conditions.

B. Co-firing supports fuel diversity.

EPA declines to include natural gas co-firing as part of the best system because "a significant benefit of a new coal-fired power plant is the fuel diversity value that it brings. Requiring the EGU to burn natural gas defeats the purpose of constructing the EGU in the first place."[624] But the opposite is true – co-firing in fact *promotes* fuel diversity and operating flexibility:

> Co-firing removes total reliance on a single source of fuel, thereby creating fuel flexibility. Thus, if a problem arises with availability of one fuel, the plant has the ability to maintain operations by switching to the other. Similarly, increases in the

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[622] Stephen Mills, IEA Clean Coal Ctr., *Combining Solar Power with Coal-Fired Power Plants, or Cofiring Natural Gas*, at 58 (Oct. 2017), https://www.usea.org/sites/default/files/Combining%20solar%20power%20with%20Coal%20fired%20power%20plants%20or%20cofiring%20natural%20gas%20ccc279.pdf.

[623] Scott Gossard, *Coal-To-Gas Plant Conversions in the U.S.*, POWER ENGINEERING (June 18, 2015), https://www.power-eng.com/articles/print/volume-119/issue-6/features/coal-to-gas-plant-conversions-in-the-u-s.html.

[624] 83 Fed. Reg. at 65,445.

> price of either fuel can be countered by changing the co-firing ratio such that the cheaper fuel predominates.[625]

Plant operators have added co-firing capabilities to existing coal-fired power plants for a variety of reasons, including fuel diversity and operating flexibility. For example, FirstEnergy does not plan to build new generation but has explored co-firing with up to 30 percent gas at its West Virginia facilities, noting that "co-firing has several benefits. It provides fuel diversity and ensures our Mon Power coal units can continue to produce low-cost electricity while supporting both the abundant low-cost natural gas supply prevalent in the region . . . [and] could help our fleet comply with future federal and/or state environmental regulations."[626]

Orlando Utilities Commission's (OUC) Stanton Plant includes two gas-fired units and two coal-fired boilers that co-fire both natural gas and landfill gas.[627] Co-firing increases the plant's fuel diversity and improves its ability to respond to variable market conditions and electricity demand:

> OUC considers that building sufficient flexibility into its generation capacity portfolio will be critical in adapting to changing market conditions. Fuel diversity is an important aspect of this strategy. For example, in 2008, the price of natural gas in the USA reached historically high levels, so coal was used to produce 78% of the company's electricity and gas produced 13%. However, as gas prices fell, the situation reversed – in 2013, gas produced 46% and coal 29%, a reflection of the changing market conditions.[628]

Duke Energy has added natural gas co-firing, or "dual fuel optionality," to its coal units at Rogers Energy Complex in North Carolina as part of the company's goal to reduce CO_2 emissions 40 percent from 2005 levels by 2030.[629] In addition to lowering environmental impacts, Duke Energy cites flexibility, cost savings, and diversification of its fuel mix as reasons for pursuing co-firing.[630] Longview Power's 700 MW advanced supercritical coal plant, one of the newest and most efficient coal-fired power plants in the country, uses natural gas for start-up; in 2016 the plant co-fired up to 20 percent of its heat input with natural gas to take advantage of low natural gas prices.[631]

C. Access to natural gas is widely available.

EPA asserts in the Proposal that co-firing should not be considered part of the best syetm because "not all areas of the country have cost-effective access to natural gas,"[632] but fails to provide any

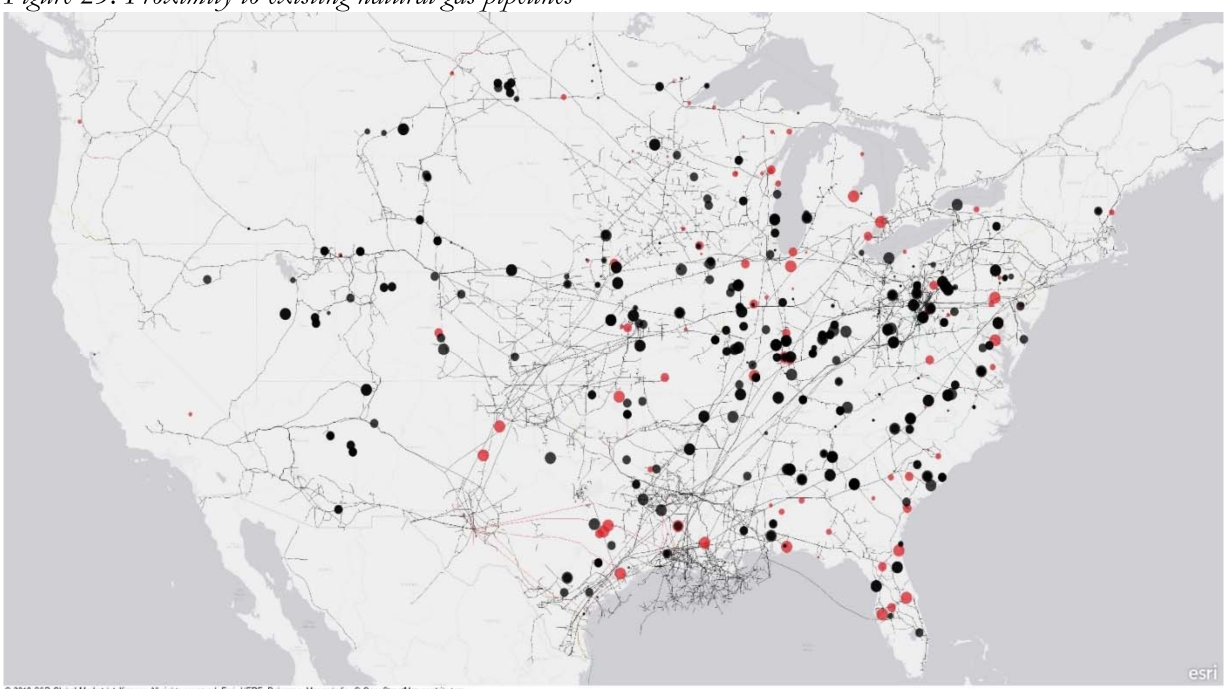
[625] Stephen Mills, *supra* note 622, at 67-68.
[626] Ken Silverstein, *Will Co-Firing Natural Gas and Coal Meet Clean Power Plan Standards?*, ENERGY MANAGER TODAY (May 2016), https://www.energymanagertoday.com/123894-0123894/.
[627] Robert Parent & James Czarniecki, Forney Corp., *Orlando Utilities Commission Ignites Shift to Fuel Diversity*, http://www.forneycorp.com/ouc-igniters-stanton/.
[628] Stephen Mills, *supra* note 622, at 67.
[629] Kim Crawford, *Duke Energy Coal Plant Modified to Generate Cleaner Energy*, DUKE ENERGY ILLUMINATION (Jan. 16, 2019), https://illumination.duke-energy.com/articles/duke-energy-coal-plant-modified-to-generate-cleaner-energy.
[630] *Id.*
[631] Aaron Larson, *Longview Power Plant Rehabilitation Results in Most Efficient U.S. Coal Plant*, POWER (Aug. 1, 2016), https://www.powermag.com/longview-power-plant-rehabilitation-results-efficient-u-s-coal-plant/.
[632] 83 Fed. Reg. at 65,445.

analysis to support this claim. Indeed, as EPA admits, "many recently constructed coal-fired power plants routinely use natural gas or other fuels such as low sulfur fuel oil for start-up operations and, if needed, to maintain the EGU in 'warm stand-by.'"[633] But EPA concludes that this widely-used technology is not part of the best system because "some areas of the U.S. have natural gas pipeline infrastructure limitations" and "[f]or new coal-fired EGUs wishing to locate in these areas, it could be either infeasible or extremely costly to co-fire natural gas."[634]

As discussed in Part III, an emission reduction measure need not be available in every conceivable location across the entire country in order to be eligible for inclusion in the best system of emission reduction; this is particularly true for new units, for which siting decisions can be made to optimize location relative to existing infrastructure.

Moreover, the factual premise of the Proposal is inaccurate. As shown in the figure below, the existing natural gas pipeline system in the U.S. is expansive. Coal facilities that already co-fire with natural gas are also dispersed across the country, indicating that co-firing is a viable and cost-effective option for many different regions in the U.S.[635]

Figure 23. Proximity to existing natural gas pipelines [636]



Red dots represent coal-fired power plants that co-fire with natural gas; black dots represent coal-fired plants that currently do not co-fire. Dots are sized based on installed nameplate capacity. Black lines represent operating natural gas pipelines; colored lines represent proposed pipeline projects.

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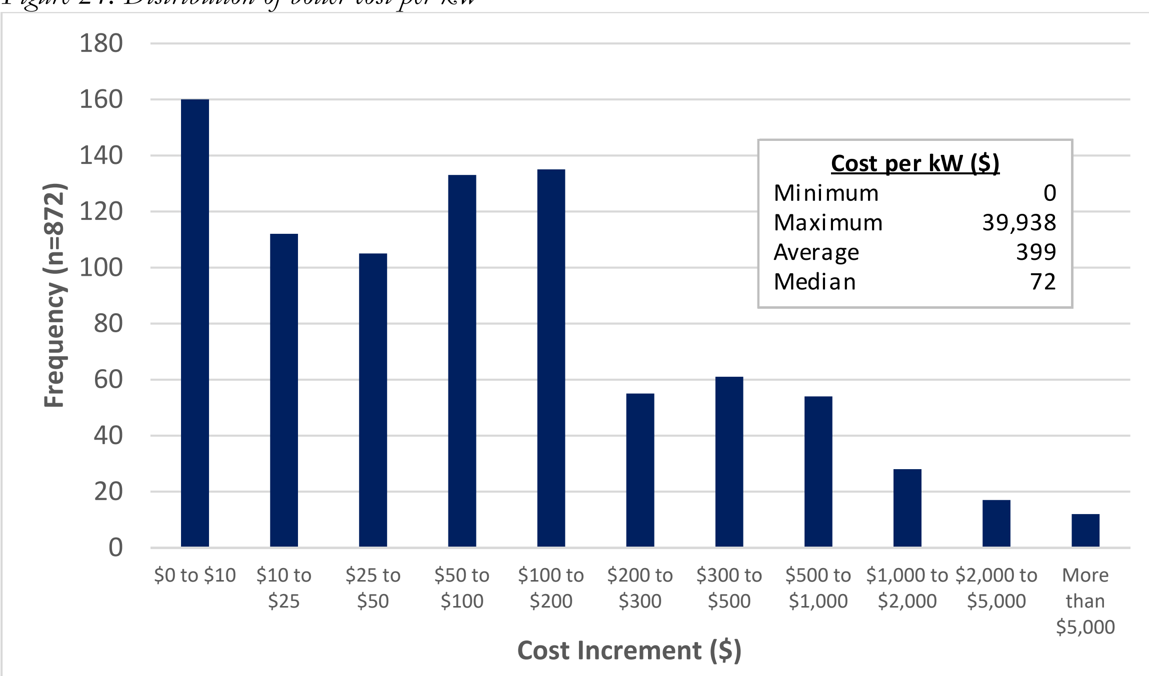
[633] *Id.*
[634] *Id.*
[635] *See also* CATF et al., Comments on Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, Doc. ID EPA-HQ-OAR-2017-0355-23806, at 42-46.
[636] Map developed by NRDC using S&P Glob. Market Intelligence's Map Tool and data sets.

EPA requests comment on "the cost to add natural gas capability to areas of the county [sic] without sufficient infrastructure."[637] A co-firing study conducted by ICF for NRDC identified and summarized the costs of 10 percent co-firing at the unit level for all existing coal-plants in the U.S. The analysis considered necessary laterals, miles of pipe, and diameter of laterals required for each of the 872 individual operating coal-fired boilers. Of the 872 boilers, 510 could connect to an available pipeline and co-fire at 10 percent at a cost of less than $100/kW (in 2016$), with a total median cost across all 872 units of $72/KW (as shown in Table 7 and Figure 24 below; full analysis available as Appendix E. This robust analysis directly conflicts with EPA's unsupported assertion that "it could be either infeasible or extremely costly to co-fire natural gas" in areas without pre-existing gas infrastructure.[638]

Table 7. Characteristics of coal-fired boilers for 10 percent co-firing

Per Boiler Values for 10 percent co-firing	Minimum	Maximum	Average	Median
Number of Laterals Required per Boiler	1	2	1	1
Miles of Pipeline Required per Boiler	0	170	27	16
Diameter of Laterals, in Inches	4	10	6	6
Total Inch-Miles of Laterals Required per Boiler	0	1,146	167	92
Total Cost to Each Boiler (Million$2016)	0	$172	$27	$14
Cost per kW of Boiler Capacity ($2016)	0	$39,938	$399	$72

Figure 24: Distribution of boiler cost per kW



[637] 83 Fed. Reg. at 65,445.
[638] *Id.*

D. Co-firing emission reductions outweigh any reduction in efficiency.

The Proposal states without support that "[c]o-firing natural gas is an inefficient use of the nation's natural gas resources."[639] EPA provides no analysis to demonstrate or quantify this claim. On the contrary, co-firing natural gas in a steam power plant can achieve significant emission reductions relative to burning coal; that a combined cycle unit burns natural gas more efficiently does not justify excluding such an effective emission-reducing measure from the best system of emission reduction.[640]

By co-firing gas, many existing units have been able to sustain much lower CO_2 emission rates than the average coal-fired unit. For example, W.A. Parish in Texas, Cope in South Carolina, and Brunner Island have seen CO_2 emission rates drop by up to a third by utilizing added co-firing capabilities (see the table below for select emission rates over 2015-2017 at co-fired facilities).

[639] *Id.*

[640] Additionally, EPA makes no showing that natural gas supplies are limited such that supplies would not be available for both co-firing plants and natural gas combined cycle plants. Even if some gas supply was re-routed for use at new sources, it is highly likely that the environmental benefit of co-firing at a coal plant would exceed the marginal efficiency losses associated with using the gas at a co-firing plant as opposed to at a combined cycle unit.

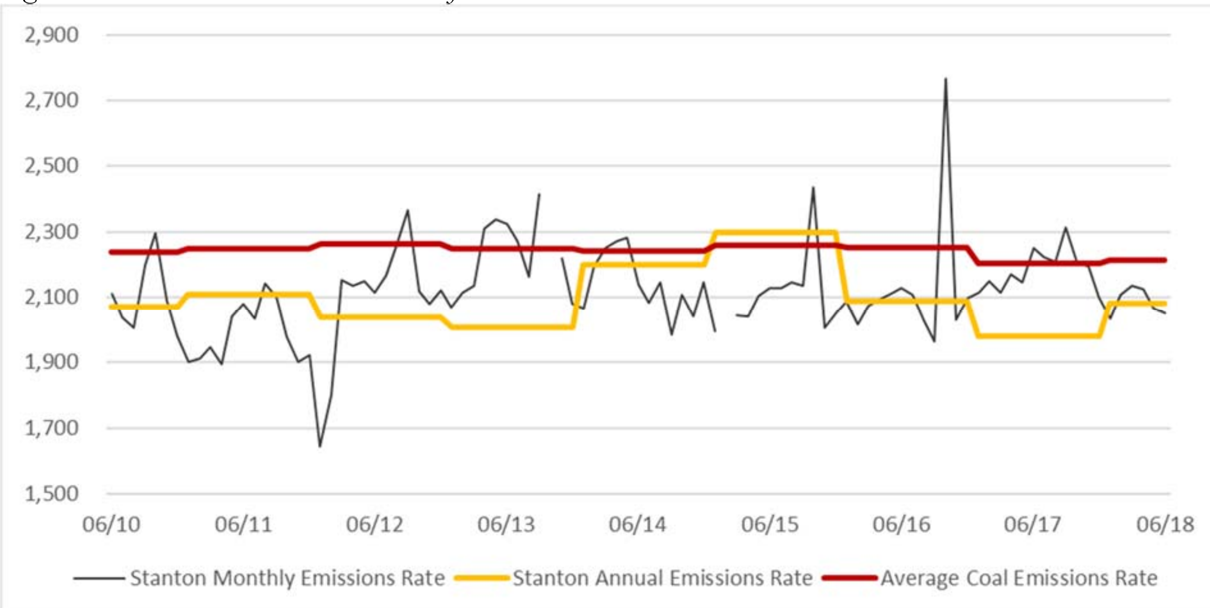
Table 8. Historic carbon emission rates for select co-fired U.S. facilities in 2015, 2016, and 2017 [641]

Power Plant	Unit Code	Co-fired/Fuel-switching?	All Fuel Types	CO2 Rate in lbs/MWh 2017	2016	2015
Jones	1	Co-Fired	Distillate Fuel Oil, Natural Gas, Subbituminous Coal	1,378	1,363	1,289
Brunner Island	3	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Natural Gas, Refined Coal	1,390	2,038	2,033
Jones	2	Co-Fired	Distillate Fuel Oil, Natural Gas, Subbituminous Coal	1,399	1,371	1,359
Brunner Island	2	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Natural Gas, Refined Coal	1,540	2,326	2,081
Brunner Island	1	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Natural Gas, Refined Coal	1,723	2,524	2,191
W.A. Parish 5-8	8	Co-Fired	Natural Gas, Subbituminous Coal	1,729	2,273	2,104
Cope	ST1	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Natural Gas, Refined Coal	1,791	1,786	1,788
W.A. Parish 5-8	7	Co-Fired	Natural Gas, Subbituminous Coal	1,959	2,108	2,061
H.L. Spurlock	4	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Tires, Waste Coal, Wood Waste Solids	1,962	1,996	2,483
Tolk	1	Co-Fired	Natural Gas, Subbituminous Coal	2,008	2,043	2,029
Bay Front	4	Co-Fired	Natural Gas, Subbituminous Coal, Tires, Wood Waste Solids	2,013	1,938	1,884
H.L. Spurlock	3	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Tires, Waste Coal, Wood Waste Solids	2,037	2,035	2,705
Monroe	3	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Petroleum Coke, Refined Coal, Subbituminous Coal	2,071	2,119	2,058
Virginia City Hybrid Energy Center	1	Co-Fired	Bituminous Coal, Distillate Fuel Oil, Waste Coal, Wood Waste Solids	2,088	2,084	2,210
Merom Generating Station	2	Co-Fired	Bituminous Coal, Distillate Fuel Oil	2,090	2,143	2,081
W.A. Parish 5-8	5	Co-Fired	Natural Gas, Subbituminous Coal	2,096	2,188	2,072

As discussed above in Part IV.B., Orlando Utilities' Stanton Plant co-fires natural gas for the purpose of increasing fuel diversity and operational flexibility; co-firing has the added benefit of significantly reducing the plant's emissions. Between 2011 and 2017, Stanton Unit 2 avoided the equivalent of 1.46 Mt of CO_2 compared to if the plant had operated at the average emissions rate for coal-fired plants in the U.S.,[642] and "[a]ir sampling has shown that Stanton's emissions are among the lowest of any coal-fired plant in the USA."[643] The monthly and annual emissions profile of Stanton Unit 2 is shown in Figure 25 below.

641 S&P Glob. Market Intelligence "Screener Tool: Power Plant Unit Details" *(Subscription required)*; EIA, EIA-906/920, *Form EIA-923 Detailed Data with Previous Form Data* (Sept. 2018), https://www.eia.gov/electricity/data/eia923/.
642 EPA, *EMC: Continuous Emissions Monitoring Systems*, https://www.epa.gov/emc/emc-continuous-emission-monitoring-systems (last visited Feb. 27, 2019).
643 Stephen Mills, *supra* note 622, at 71.

Figure 25. Stanton Unit 2 Emissions Profile [644]



The emission reductions achieved by existing co-fired units is in line with EPA's own analysis of the emission reduction potential of fuel-switching measures in the Clean Power Plan rulemaking: EPA found CO_2 emissions could fall by "approximately 40 percent in the case of conversion from 100 percent coal to 100 percent natural gas, and proportionately smaller for partial co-firing of coal with natural gas."[645]

In addition to reductions in carbon emissions from coal-fired power plants, co-firing can also significantly reduce co-pollutants, like NO_x and SO_2. For example, Breen Energy Solutions, headquartered in Bridgeville, Pennsylvania, has noted that a 35 percent natural gas feed with their co-firing system could reduce SO_2 emissions by 35 percent, NO_x emissions by 45 percent, particulates by 35 percent, mercury by 35 percent, and CO_2 by 20 percent.[646]

This Proposal fails entirely to "articulate a satisfactory explanation" for discounting the availability of co-firing to meet the current standard or EPA's exclusion of co-firing from the best system of emission reduction even though greater emission reductions are achievable at low cost through the use of co-firing compared to the proposed "best system;" therefore, finalizing the Proposal would be arbitrary and capricious.[647]

V. Efficiency is not the best system of emission reduction, and the proposed standard is entirely unreasonable.

As described in detail above, CCS is available at reasonable costs and reduces emissions further than efficiency measures, therefore efficiency cannot be the *best* system as required by section 111. In

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644 EPA, *EMC: Continuous Emissions Monitoring Systems*, https://www.epa.gov/emc/emc-continuous-emission-monitoring-systems (last visited Feb. 27, 2019).
645 80 Fed. Reg. at 64,756.
646 Stephen Mills, *supra* note 622, at 62.
647 *State Farm*, 463 U.S. at 43.

2015, EPA rejected efficiency because CCS was a *better* means of pollution reduction and efficiency measures would not reduce CO_2 as compared to business as usual or provide an incentive for technology innovation.

Not only is efficiency not the best system, the standard that EPA chose is unreasonable as well. The Agency must maximize emission reductions using state-of-the-art controls projected to be available during the regulatory future. Instead, EPA chose a performance standards of 1,900-2,200 lbs. CO_2/MWh, which coal-fired power plants were meeting 30 years ago,[648] based on technology that has been available for 50 years.[649] In 2015, EPA assumed an 1,800 lbs. CO_2/MWh emission rate for a new "less efficient" coal-fired power plant when it was comparing emission reductions from partial-CCS with business as usual.[650]

In the Proposal, EPA reviewed emission data for domestic coal-fired power plants from 2005 to 2017 to determine the emission rate equivalent to the best system of emission reduction.[651] The emission rates were then "normalized" to the lowest common denominator, taking into account steam cycle, coal type, average ambient temperature and coal type.[652] So, for example, while the actual maximum reported annual emission rate for Weston Unit 4 was 1,763 lbs. CO_2/MWh, EPA "normalized" the rate upwards 10 percent to 1,941 lbs. CO_2/MWh. Again, as EPA stated in 2015, "the whole purpose of a new source standard which is to reflect best system of emission reduction, not some type of least common denominator."[653]

Further, the average age for units in EPA's data set for the current rulemaking is more than 45 years; nonetheless 316 of 678 units in EPA's sample met EPA's proposed limit for new "highly efficient" units for a year at least once in the past 10 years with no regulatory requirement in place.

The Proposal's review of historical emission rates achieved by old coal plants is directly counter to the forward-looking, technology-forcing demands of the Clean Air Act. In 2015, the DOE/NETL "Cost and Performance Studies" indicated that new bituminous plants could meet a rate of 1,618 lbs. CO_2/MWh and low-rank plants could meet 1,737 lbs. CO_2/MWh.[654] EPA confirmed in the Proposal that historically "some domestic coal plants have operated with annual emission rates of less than 1,700 lbs. CO_2/MWh."[655]

Today, coal-fired technology has advanced to efficiencies designated as "ultrasupercritical" (USC) and now, "advanced ultrasupercritical" (A-USC). These technologies have been installed elsewhere around the globe, most notably Europe, China and Japan, and are commercially available in the U.S.,

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648 James E. Staudt & Jennifer Macedonia, *Evaluation of Heat Rates of Coal Fired Power Boilers*, Power Plant Pollutant Control "MEGA" Symposium (Aug. 2014), http://www.andovertechnology.com/images/staudt_paper_4.pdf.
649 83 Fed. Reg. at 65,448.
650 80 Fed. Reg. at 64,574.
651 EPA, Best System of Emission Reduction (BSER) for Steam Generating Units and Integrated Gasification Combined Cycle (IGCC) Facilities, Doc. ID: EPA-HQ-OAR-2013-0495-11954 (Dec. 2018).
652 *Id.* at 7.
653 EPA, Response to Comments, Standards for Fossil Fuel-fired Electric Utility Steam Generating Units (Boilers and Integrated Gasification Combined Cycle Units), at 6-225, Doc. ID: EPA-HQ-OAR-2013-0495-11865 (Oct. 23, 2015).
654 EPA, Achievability of the Standard for Newly Constructed Steam Generating Units, Doc. ID: EPA-HQ-OAR-2013-0495-11771 (July 31, 2015).
655 *Id.*

and achieving standards below 1,500 lbs. CO_2/MWh.[656] EPA must look internationally to determine the best system of emission reduction.[657]

The Proposal to base standards for small coal plants on subcritical technology (blue in chart below) and large plants on supercritical technology (yellow in chart below) entirely fails the section 111 mandate to base standards on the *best* system.

Figure 26: Reducing CO2 Emissions through Efficiency Improvements in Coal-Fired Power Stations

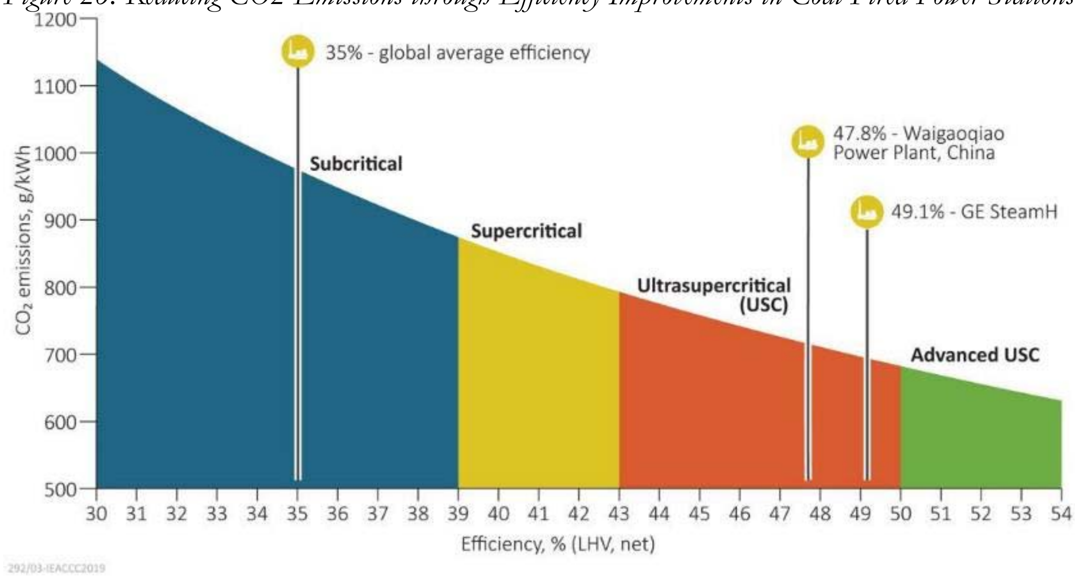

Image Source: IEA Clean Coal Centre 2019

Ultrasupercritical plants are in operation throughout the world, with 226 units in operation in China, 22 in South Korea, 19 in Japan and 13 in Germany.[658] EPA must require "maximum feasible control of new sources at the time of their construction"[659] and therefore if EPA chooses efficiency as the best system, the standard must be based on the world's *most* efficient plants, such as the USC Isogo plant in Japan, GE's RDK8 plant in Germany, and the Shanghai Waigaoqiao No 3 plant in China,[660] not historical, domestic, "normalized" emission rates accommodating the least common denominator.

VI. Conclusion

An Agency may, of course, adjust regulations as facts and policy change. However, it must supply "good reasons" for the change and cannot leave "unexplained inconsistency." Moreover, as in any

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[656] Wood Mackenzie, *Outlook and Benefits of An Efficient U.S. Coal Fleet: Final Report* (Jan. 2019), https://nma.org/wp-content/uploads/2019/01/Outlook-and-Benefits-of-An-Efficient-U.S.-Coal-Fleet.pdf.

[657] *See Sierra Club*, 657 F.2d at 364 (achievability of standard upheld, even though no domestic source was achieving the promulgated limit, due in part to successful operation of the technology in Japan); *see also Lignite Energy Council v. EPA*, 198 F.3d at 394 n.3 (section 111(b) standard of performance justified in part based on data from "foreign boilers burning lignite").

[658] Dr. Lesley Sloss, *supra* note 506, at 19.

[659] S. Rep. No. 91-1196, at 16 (1970).

[660] Dr. Lesley Sloss, *supra* note 506, at 20.

rulemaking, the Agency is tethered to the purpose and mandate of the statute and must engage in reasoned decision-making.

The Clean Air Act requires "maximum feasible control of new sources" to promote public health and welfare and prevent air pollution. Section 111(b) of the Act, in particular, requires the Administrator to base standards of performance for new sources on the *best* system of emission reduction.

EPA fails at every turn. The record underlying the current rule shows that the standard is achievable and established that partial-CCS is adequately demonstrated, cost reasonable, broadly available, and furthers the health-protective purposes of the Act. This record has only gotten stronger since the rule was finalized. Since 2015 another power plant, without a regulatory driver, has installed *full*-CCS, Congress has passed significant tax incentives for CCS, and costs have declined with promise to decline even further.

With all evidence pointing in one direction, EPA inexplicably rushes in the opposite direction relying on flawed and incomplete analysis and legal errors. The Clean Air Act is a technology-forcing and forward-looking statute requiring bold action in the face of increasing pollution harms. It does not permit EPA to accommodate the lowest common denominator to set a meaningless standard based on decades old technology. This Proposal is hopelessly backward and inconsistent with the Act and must be withdrawn.