COMMENTS OF THE POWER GENERATORS AIR COALITION ON THE U.S. ENVIRONMENTAL PROTECTION AGENCY'S NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE; PROPOSED RULE

88 Fed. Reg. 33,240 (May 23, 2023)

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Docket ID No. EPA-HQ-OAR-2023-0072

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") in response to EPA's proposed rules entitled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule ("Proposed Rules"), which were published in the Federal Register on May 23, 2023.[1] The Proposed Rules consist of five separate rules: (1) revised new source performance standards ("NSPS") for greenhouse gas ("GHG") emissions from new fossil fuel-fired stationary combustion turbine electric generating units ("EGUs"); (2) revised NSPS for GHG emissions from modified fossil fuel-fired steam generating EGUs; (3) emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs; (4) emission guidelines for GHG emissions from existing stationary combustion turbine EGUs; and (5) repeal of the Affordable Clean Energy Rule.[2]

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[1] 88 Fed. Reg. 33,240 (May 23, 2023).

[2] *Id.*

I. Background

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[3] PGen's members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired EGUs that are the subject of the Proposed Rules, as well as renewable resources, like wind and solar, and carbon-free nuclear power plants. As such, PGen is uniquely qualified to provide comments to EPA because its members have owned and operated fossil fuel-fired EGUs for decades and are subject to various provisions of the Clean Air Act ("CAA" or "the Act"), including section 111, the provision governing the Proposed Rules.

At the outset, PGen wants to make clear that it understands the importance of reducing GHG emissions to address climate change. The electricity generating sector has made significant GHG reductions, and is the industry with by far the greatest amount of reductions from 2005 to

[3] Additional information about PGen and its members can be found at https://pgen.org/.

2021.[4] During that period, the electric power sector's GHG emissions have fallen nearly 36 percent,[5] and the sector is no longer the biggest contributor to U.S. GHG emissions.[6] The vast majority of PGen members have established goals to reduce their GHG emissions, and several PGen members have set net-zero goals.

While PGen members take seriously the need to reduce GHG emissions, they take equally seriously their obligation to provide reliable electricity at an affordable price. PGen members are concerned that the Proposed Rules will interfere with this critical obligation, which could undermine public support for electric sector efforts to reduce emissions through low- and zero-carbon sources like wind, solar, and nuclear.

PGen has been actively engaged with EPA on this important issue. When EPA was seeking information during the pre-proposal stage, PGen met with EPA in Research Triangle Park on November 17, 2022, and then followed up with written comments to EPA's pre-proposal non-rulemaking docket on December 22, 2022.[7] PGen appreciates that the Agency appears to have adopted some of PGen's recommendations in the Proposed Rules. For example, PGen supports EPA's decision to allow states to adopt flexible compliance mechanisms such as emission averaging and trading—but reiterates its request for EPA to develop a model trading rule that states could easily adopt as an approvable state plan and that could serve as a federal plan where necessary. PGen

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[4] Center for Climate and Energy Solutions, U.S. Emissions, https://www.c2es.org/content/u-s-emissions/ (citing EPA and EIA data for 2022).

[5] *Id.* By comparison, the transportation sector's GHG emissions fell by only a little less than 9 percent and the industrial sector reduced its emissions by a little more than 4 percent over the same period of time.

[6] *Id.* (graphic showing Energy-Related Carbon Dioxide Emissions by Sector).

[7] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723-0031 (Dec. 22, 2022) ("PGen Pre-Proposal Comments"). The PGen Pre-Proposal Comments are attached hereto as Attachment A and incorporated by reference.

also appreciates that EPA allows EGUs with near-term retirement dates to be subcategorized differently so as not to have to comply with as stringent requirements as those EGUs that will be operating longer, although PGen believes that those subcategorization dates need to be adjusted further out in time to ensure electric reliability concerns are addressed. PGen also appreciates EPA's acknowledgment in the Proposed Rules that gas-fired peaking units (both new and existing) are needed to ensure grid stability during the transition to low carbon energy.

PGen's detailed comments on the Proposed Rules follow. PGen remains available to continue to work with EPA in any way that the Agency may find helpful as it considers the Proposed Rules.

II. Executive Summary

PGen provides this Executive Summary for the convenience of the reader. It does not summarize every point made within these comments and should not be a substitute for reading the comments in their entirety.

EPA's Proposed Rules regarding regulation of GHG emissions from EGUs impermissibly relies on technologies that do not meet the legal threshold set out by Congress in section 111 of the CAA and threatens to impose unrealistic timelines. Importantly, the Proposed Rules will have a negative impact on electric reliability and affordability. PGen's comments on the Proposed Rules are summarized below.

The Proposed Rules threaten both the reliability and affordability of electricity, and EPA needs to carefully analyze this issue more broadly to avoid instability in the electric grid (Section III).

- The electric generating industry is in a period of transition toward increased use of renewable energy and decreasing use of fossil fuel-fired generation, with the retirement of fossil fuel-fired EGUs, particularly coal-fired EGUs, occurring at a rapid pace. These retirements have strained the grid and threatened electric reliability, as expressed by the North American Electric Reliability Corporation ("NERC").

- The Proposed Rules are not the only EPA regulations that will affect EGUs—and thus reliability. EPA needs to take those other rules into account and should consider harmonizing the compliance and retirement dates to make them consistent across all of the rules. EPA also needs to consider how other regulatory initiatives outside of environmental regulations—such as regulations increasing the use of electric vehicles—will affect electric reliability.
- The Proposed Rules will compound the issue of the retirement of fossil fuel-fired EGUs, and will lead to capacity factor restrictions on many units that do not retire. This will lead to further negative effects on electric reliability. EPA needs to consult with the Department of Energy ("DOE"), the Federal Energy Regulatory Commission ("FERC"), regional reliability authorities, and the states to ensure reliability is adequately addressed.
- EPA should consider providing a safety valve exemption for EGUs that adopt capacity factor restrictions that would allow those units to operate beyond those restrictions as needed for reliability during periods of extreme load.

The Proposed Rules violate the requirements of section 111 of the CAA (Section IV).

- While carbon capture and storage ("CCS"[8]) is a promising technology that is making advancements through a variety of pilot projects throughout the United States, it has not yet reached the legal threshold of being an adequately demonstrated technology. EPA's proposed determination that CCS is adequately demonstrated for new and existing combustion turbines is not grounded in any actual experience with this technology at these types of EGUs.
- Similarly, EPA's proposed determination that CCS is adequately demonstrated for modified and existing coal-fired steam generating units violates section 111 because there is no evidence that CCS technology can capture 90 percent of the carbon dioxide ("CO_2") emissions from a facility that is not a slipstream facility and do so on a consistent basis, and because there is no evidence that CCS technology can work on large, commercial scale EGUs.
- The proposed NSPS for new and modified fossil fuel-fired EGUs and the presumptively approvable emission limitations for existing fossil fuel-fired EGUs that are based on CCS are not achievable across the country and thus violate section 111. Many areas of the country do not have ready access to geologic storage and the construction of a CO_2 pipeline is expensive, time-consuming, and subject to organized public opposition.
- CCS has several issues that prevent it from being a "best" system of emission reduction, including geologic storage issues. CCS also requires significant water for process operations, which further limits its geographic availability. There is also a significant parasitic load associated

[8] CCS is also sometimes referred to as carbon capture, utilization, and storage ("CCUS"). The "utilization" piece of CCUS stands for the concept that the captured carbon could be re-used in industrial processes such as enhanced oil recovery ("EOR") or by converting it into a product like concrete.

with the operation of CCS equipment that EPA has not fully examined. CCS continues to be expensive, even with the possibility of funds under the Inflation Reduction Act ("IRA").

- Hydrogen co-firing at natural gas-fired combustion turbines is another promising technology that does not yet meet the CAA's requirements for adequate demonstration. There is no evidence of the ability of combustion turbines to combust hydrogen at the levels contemplated by the Proposed Rules over an extended period of time, as confirmed by one of the largest construction and engineering companies involved in the development of hydrogen projects.
- EPA has also failed to adequately address the significant increases in nitrogen oxide ("NOx") emissions that result from hydrogen combustion.
- There is not a current supply of low-GHG hydrogen that can come even close to being able to provide the amount of hydrogen necessary under the Proposed Rules, and EPA's speculation that it will be available in the timelines set out in the rules is impermissible "crystal ball inquiry."
- Even if there were an ample supply of low-GHG hydrogen (which there is not), the infrastructure for transporting and storing the hydrogen is completely lacking, and there is no guarantee it will be available by 2032 and 2038 to fulfill the requirements of the Proposed Rules.
- The Proposed Rules' requirements that natural gas-fired EGUs combust significant amounts of hydrogen impermissibly redefines the source. The same is true for the Proposed Rules' requirements that natural gas be co-fired at coal-fired EGUs. Moreover, the vast majority of coal-fired EGUs do not have access to any amount of natural gas.
- EPA's assumption that technologies and their required infrastructure will be adequately demonstrated and achievable several years—and in some cases more than a decade—in the future is not reasonable and violates the CAA.

EPA's timeline for compliance with the Proposed Rules is unrealistic (Section V).

- The timelines set out in the Proposed Rules are unrealistic and unachievable. For example, existing coal-fired steam generating units that are characterized as long-term are subject to presumptively approvable emission limits based on CCS with 90 percent capture by 2030. Unless an owner or operator has already begun the process of pursuing CCS for the unit, it is already too late. There are too many permitting and other hurdles to overcome within the allotted time proposed. Similar issues exist for other parts of the Proposed Rules.

The Proposed Rules violate the major questions doctrine, which the Supreme Court warned EPA about in *West Virginia v. EPA* (Section VI).

- The Proposed Rules lead to the exact same result that the Supreme Court found unlawful in the Clean Power Plan: a shifting away from fossil fuel-fired generation and a dictation of what EPA views as the optimal mix of energy sources in the United States, which it lacks the authority to do.

The applicability dates for the Proposed Rules are incorrect as a matter of law (Section VII).

- EPA's original analysis in the preamble to the Proposed Rules and in the proposed regulatory text was correct. Namely, an existing source for the purposes of the Proposed Rules is a fossil fuel-fired EGU that commenced construction before January 8, 2014 (or commenced reconstruction before June 18, 2014). EPA's June 12, 2023 "Memo to the Docket" regarding applicability for existing combustion turbines is incorrect under the CAA. Combustion turbines that were constructed after January 8, 2014, and whose CO2 emissions were subject to Subpart TTTT, are "new sources" under section 111, and therefore cannot be existing sources for the purposes of these rules.

The Proposed Rules impermissibly restrict states' remaining useful life and other factors ("RULOF") determinations (Section VIII).

- EPA should not unduly restrict states' ability to examine RULOF. The Proposed Rules put too many restrictions on a state's RULOF analysis. For example, EGUs subject to a RULOF determination should be allowed to participate in an emissions trading program.
- EPA should make clear that if a state plans results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that state plan should be approved by EPA as "satisfactory."
- States must be allowed to consider energy impacts and requirements as part of its RULOF analysis and should be allowed to give an EGU a less stringent emission limitation to preserve electric reliability.
- States should be allowed to modify an EGU's subcategory parameters to address RULOF issues.

EPA needs to assist the states by providing a model trading rule based on mass-based presumptively approvable emission limits that states can adopt (Section IX).

- EPA should issue a model trading rule for existing sources that states may opt into and that would be a fully approvable and automatic state plan. There are many policy reasons that support this approach, and it is one that EPA has followed in the past.
- EPA should not unduly restrict emissions trading. Any model rule issued by EPA should be broadly applicable across all affected fossil fuel-fired EGUs.
- EPA should provide states with alternative mass-based presumptively approvable emission limits. Mass-based limits have numerous advantages. This should be done even if EPA does not issue a model trading rule.

EPA's environmental justice analysis should examine the effects on environmental justice communities of decreased electric reliability and lack of access to affordable electricity (Section X).

- The costs of new environmental regulations are likely to fall disproportionately on lower-income households and environmental justice communities. EPA needs to consider this as part of its analysis of the Proposed Rules.
- Electric reliability problems are also most likely to be borne by environmental justice communities that will lack the means to be able to install emergency backup generation to avoid the consequences of any electric service disruptions. EPA needs to consider energy justice issues in its analysis of the Proposed Rules.
- Recent evaluations of the cap-and-trade programs, including by California as part of its Carbon Cap-and-Trade Program, show that emissions trading is unlikely to have negative environmental justice impacts and, in fact, should achieve the opposite result.
- EPA has not adequately responded to safety concerns raised by a number of environmental justice organizations.

EPA's Integrated Planning Model ("IPM") analysis on which the Proposed Rules rely is deeply flawed (Section XI).

- EPA's base case from which the Proposed Rules are evaluated contains unrealistic and wildly optimistic assumptions about the impact of the IRA on coal retirements and CCS retrofits, as well as the amount of renewables that would replace the retired generation. EPA's base case is inconsistent with every other available model, including the one published by the Energy Information Administration ("EIA").
- IPM's updated baseline fails to consider grid reliability issues confronting the electric power sector, particularly for 2030. The IPM modeling replaces dispatchable power with non-dispatchable renewable generation without any consideration of the different nature of these two types of generating assets. EPA also fails to consider factors relating to capacity in queues, length of time in queues, and project completion of renewables.
- EPA's 2030 "base case," which projects CCS would be used by 2030 at 27 coal-fired units (about 9 gigawatts ("GW") of capacity), contains substantial errors and unreasonable assumptions.

EPA failed to provide sufficient time for public comment on the Proposed Rules in violation of the CAA and the Administrative Procedure Act (Section XII).

- The time period provided by EPA for public comment on the Proposed Rules was insufficient and violated the CAA and the Administrative Procedure Act because it failed to give affected parties adequate time to develop evidence in the record to support their positions on the Proposed Rules.

- EPA ignored requests from numerous affected parties for additional time, including requests from state environmental agencies, regional transmission operators, and Congress.
- EPA improperly released new IPM data that materially changed EPA's original analysis of the Proposed Rules with a mere 21 business days left in the comment period.
- EPA provided less time for comment on the Proposed Rules, which consist of five separate rules, than it did in previous rulemakings where the rules were proposed in smaller rulemaking packages.
- EPA is not under any deadlines that would require it to shorten the comment period.

Additional items needing clarification or changes (Section XIII).

- The definition of "electric generating capacity" needs clarification. Even with EPA's recent release of a memo to the docket, a lot of confusion remains on this point.
- EPA should consider eliminating the concept of heat recovery steam generator ("HRSG") apportionment in the Proposed Rule because it is a bad policy to penalize combined cycle units that only utilize recovered waste heat to augment the output of the gas-fired turbine. The steam produced by the HRSG does not cause CO_2 emissions.
- The timing for increments of progress under the Proposed Rules should not begin to run until after a state plan has been approved by EPA.
- EPA should eliminate the proposed requirement for affected EGUs to establish a "Carbon Pollution Standards for EGUs website." This proposed requirement is burdensome, unnecessary, and inconsistent with the principles of the Paperwork Reduction Act.

III. The Proposed Rules Threaten Both the Reliability and Affordability of Electricity, and EPA Needs to Carefully Analyze this Issue More Broadly to Avoid Instability in the Electric Grid.

The electric generating industry is in a period of transition toward increased use of renewable energy and decreasing use of fossil fuel-fired generation. The retirement of coal-fired EGUs has been occurring at a rapid pace. From 2010 to 2019, about 40 percent of U.S. coal generating capacity closed.[9] According to the EIA, 14.9 gigawatts ("GW") of generating capacity was scheduled to retire

[9] Phys.org, *50 US coal power plants shut under Trump* (May 9, 2019), https://phys.org/news/2019-05-coal-power-trump.html (noting the closure of 289 plants between 2010 and 2019).

in the United States in 2022, with all of those retirements coming from baseload capacity[10] (85 percent from coal, 8 percent from natural gas, and 5 percent from nuclear).[11] These numbers are only accelerating in 2023. The EIA estimates that 15.6 GW of electric generating capacity will retire this year with 98 percent of those retirements being fossil fuel-fired plants (58 percent from coal and 40 percent from natural gas).[12] Notably, retirements of natural gas-fired plants, which also provide baseload power, are showing a tremendous increase in 2023, with 6.2 GW of natural gas-fired generation planning to retire.[13]

The high pace of coal-fired EGU retirements has strained the grid and threatened reliability. The President and Chief Executive Officer of NERC recently testified before Congress that while NERC finds "that the energy transformation can be navigated in a reliable way," it "is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and

[10] Baseload capacity consists of those EGUs that provide firm, dispatchable capacity that can be ready to serve electric load whenever needed. This is in contrast to intermittent resources such as wind and solar that are available only when the wind blows and the sun shines. EPA needs to differentiate and understand the differences between *energy* and *capacity*. At a minimum, an electricity transmission system requires adequate dispatchable EGU capacity to meet peak demand. Intermittent EGU resources are not "dispatchable"; they are an energy source to a transmission system, not a capacity resource. Intermittent resources tend to be low-emitting units that are good for displacing emissions from dispatchable units, but they do not replace the need for reliable capacity that comes from baseload generation.

[11] EIA, Today in Energy, *Coal will account for 85% of U.S. electric generating capacity retirements in 2022* (Jan. 11, 2022), https://www.eia.gov/todayinenergy/detail.php?id=50838.

[12] EIA, Today in Energy, *Coal and natural gas plants will account for 98% of U.S. capacity retirements in 2023* (Feb. 7, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55439.

[13] *Id.*

more serious long duration reliability disruptions, including the possibility of national consequence events."[14]

In its 2022-2023 Winter Reliability Assessment, NERC expressed concern that "[a] large portion of the North American [bulk power system] is at risk of insufficient electricity supplies during peak winter conditions."[15] For the Texas ERCOT region, NERC worried that EPA's coal ash disposal regulations "could impact the availability of two coal-fired generation units (combined total of 1,477 megawatts ("MW")) in the last weeks of winter. These units could be important resources during extreme conditions…."[16] Similarly, MISO (the independent system operator in the Midwest) has had its reserve margins fall by over 5 percent since the winter of 2021-2022 because of nuclear and coal-fired EGU retirements.[17] Further retirements within MISO as a result of the Proposed Rules will exacerbate the problem. One of NERC's recommendations is that "regulators should … take steps to delay imminent generation retirements if essential to reliability."[18] NERC's 2022 Summer Reliability Assessment expressed similar reliability concerns, especially in MISO.[19]

NERC's assessment of reliability in North America did not improve with its 2023 Summer Reliability Assessment. NERC found nearly the entire United States to be at an elevated risk for

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[14] Testimony of J.B. Robb, President and CEO, NERC, Before the Senate Committee on Energy and Natural Resources at 1 (June 1, 2023), https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[15] NERC, 2022-2023 Winter Reliability Assessment at 4 (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

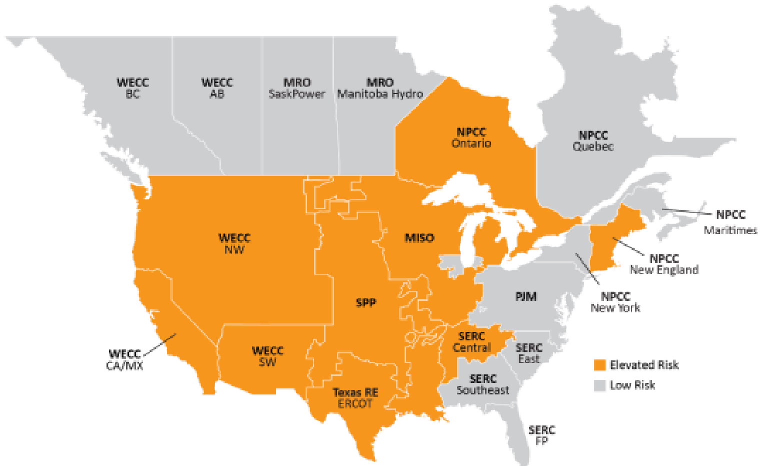
[16] *Id.*

[17] *Id.*

[18] *Id.* at 5.

[19] NERC, 2022 Summer Reliability Assessment at 4 (May 2022) (noting MISO is at a "high risk of energy emergencies during peak summer conditions"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

having insufficient operating reserves during periods of more extreme summer conditions.[20] Figure 1 from NERC's 2023 Reliability Assessment is reproduced below.[21] The areas highlighted in orange are at elevated risk.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

NERC also identified EPA's Good Neighbor Plan as presenting reliability issues because "[c]oal and natural gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment."[22] NERC cautioned regional operators, grid operators, and balancing authorities "to be vigilant for emissions rule constraints that affect generator dispatchability," and explained that "[s]tate regulators and industry

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[20] NERC, 2023 Summer Reliability Assessment at 5-6 (May 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[21] *Id.* at 5.

[22] *Id.*

should have protocols in place at the start of summer for managing emergent requests" for waivers.[23]

NERC's specific mention of the Good Neighbor Plan, which will go into effect on August 4, 2023, should remind EPA that its regulations have an effect on retirements and utilization of electric generating units. In addressing how reliability and affordability of electricity will be affected by the Proposed Rules, the Office of Air and Radiation cannot look at the proposal in a silo or fail to look at what its sister offices, such as the Office of Water and Office of Solid Waste and Emergency Response, are proposing. In addition to the recently finalized Good Neighbor Plan, EPA has numerous other proposed or recently finalized regulations that will lead to further fossil fuel-fired EGU retirements in the electric generating industry—and therefore an effect on the reliability and affordability of electricity. These rules include EPA's Effluent Limitation Guidelines ("ELG") and Coal Combustion Residuals ("CCR") rulemaking.[24]

These rulemakings are complex and contain various retirement and compliance dates. This makes compliance decisions for the owners and operators of affected EGUs complicated and difficult. A sampling of the compliance dates and retirements dates included in the Proposed Rules, the ELG rules, and the CCR rules illustrates the problem:

- 2020 CCR Rule Revisions: Retirement dates of 10/17/23 or 10/17/28
- 2020 ELG Rule: Retirement date of 12/31/38
- 2023 ELG Proposal: Retirement date of 12/31/32
- 2023 Proposed GHG Rules: Retirement dates of 12/31/31, 12/31/34, or 12/31/39
- 2020 CCR Rule Revisions: Compliance date of 10/15/23
- 2020 ELG Rule: Compliance date of 12/31/25
- 2023 ELG Proposal: Compliance date of 12/31/29
- 2023 Proposed GHG Rules: Compliance date of 12/31/29

[23] *Id.*

[24] 88 Fed. Reg. 18,824 (Mar. 29, 2023) (EPA Office of Water proposed rule for supplemental effluent limitations guidelines for the steam electric power generating point source category); 88 Fed Reg. 31,982 (May 18, 2023) (EPA Office of Land and Emergency Management proposed rule addressing the disposal of coal combustion residuals from electric utilities).

EPA should consider harmonizing these compliance dates and retirement dates to make them consistent across all of these rules.[25]

In addition to performing a more holistic analysis of the impact of the Proposed Rules, EPA also needs to consider how efforts outside environmental regulations may affect electric reliability and affordability such as regulations that will result in exponential increases in the use of electric vehicles in the transportation sector and analyze how the Proposed Rules may affect the ability of electric generators to meet that increased load on the electric system in the United States.[26] Proposing regulations that the Agency knows will hasten the retirement of fossil fuel-fired EGUs in the United States (thus decreasing the availability of baseload generation) while simultaneously proposing regulations that will increase the need for electricity in the United States is ill-conceived and poor public policy. EPA needs to examine this issue thoroughly. Failure to do so could result in erosion of public support for EPA's greenhouse gas programs.

The increased retirements of fossil fuel-fired EGUs in recent years has unequivocally decreased electric reliability. This can be seen in the exponential increase in requests to DOE under section 202(c) of the Federal Power Act to suspend compliance with environmental regulations in order to preserve the reliability of the bulk electric power system. From 2000 to 2019, DOE issued 8 orders under section 202(c).[27] That number of orders, which took place over a 20-year period of

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[25] What EPA should *not* do, is what it did in this rulemaking: adopt such unrealistic and wildly optimistic assumptions regarding the impact of the IRA, in a transparent attempt to make the impact of the Proposed Rules on fossil fuel-fired EGU retirements much less than it plainly will be. *See infra* Section XI.

[26] *See, e.g.*, 88 Fed. Reg. 29,184 (May 5, 2023) (EPA proposed multi-pollutant emissions standards for model years 2027 and later light-duty and medium-duty vehicles); California's Advanced Clean Cars II regulations, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program.

[27] DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority – Archived*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

time, was nearly matched in 2022 alone, when 7 such emergency orders were issued.[28] Eleven emergency orders have been issued by DOE since 2020.[29]

Even before EPA issued the Proposed Rules, the EIA was releasing information showing that concerns about reliability will only increase in the next few years as many more retirements of the remaining coal-fired EGUs are expected. The EIA reports that 28 percent of the remaining coal-fired EGUs will retire by 2035,[30] with nearly all of those retirements taking place by the end of 2029.[31] Nearly 10,000 MW will be retired in 2028 alone, driven primarily by compliance with EPA's ELG rules, which limit waste water discharges from power plants.[32] The EIA says that cost of compliance with the ELG rules, which involve significant capital investment, is "likely influencing the decision to retire some of these coal-fired units."[33]

Unfortunately, the Proposed Rules compound the problem of significant capital investments either forcing early retirement or significantly curtailing the amount an EGU may run. This will further strain electric reliability, raise health and safety issues resulting from electric service disruptions, and increase the cost of electricity. These effects run the risk of undermining public support for GHG reducing programs and conflict with the purpose of the CAA "to promote the public health and welfare and the productive capacity of [the nation's] population."[34] The Proposed

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[28] DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.

[29] *Id.*

[30] EIA, Today in Energy, *Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035* (Dec. 15, 2021), https://www.eia.gov/todayinenergy/detail.php?id=50658.

[31] EIA, Today in Energy, *Nearly a quarter of the operating U.S. coal-fired fleet scheduled to retire by 2029* (Nov. 7, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54559.

[32] *Id.*

[33] *Id.*

[34] CAA § 101(b)(1); 42 U.S.C. § 7401(b)(1).

Rules require significant capital investment into coal-fired EGUs unless they commit to retire prior to 2032 (i.e., be subcategorized as an "imminent-term" unit)[35] or adopt a severe limit on their capacity factor by 2030 and commit to retire by 2035 (i.e., be subcategorized as a "near-term" unit).[36] Any coal-fired EGU that intends to operate after January 1, 2035, but retire before January 1, 2040, (i.e., a unit subcategorized as a "medium-term" unit), will need to make a substantial capital investment in the unit unless the unit already has access to natural gas and the capability to co-fire natural gas at high levels.[37] For any unit that intends to operate after January 1, 2040 (i.e., a unit subcategorized as a "long-term" unit), it must accelerate these capital investments and complete them by January 1, 2030.[38] Further, any medium-term unit must meet a host of interim "increments of progress" by that date.[39] All of these requirements will almost certainly hasten the retirement of additional coal-fired EGU capacity beyond that anticipated by the EIA.

The Proposed Rules will also result in capacity factor restrictions on large, frequently used combustion turbines, which could also have a deleterious effect on electric reliability—particularly in areas that heavily rely on combustion turbines for baseload generation such as Texas. Any natural gas-fired combustion turbine that is greater than 300 MW in size and that operates at a capacity factor greater than 50 percent[40] will need to make significant capital investment into those units by

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[35] Proposed 40 C.F.R. §§ 60.5740b(a)(1)(D), (a)(3)(i)(C); 60.5775b(c)(4).

[36] *Id.* §§ 60.5740b(a)(1)(C), (a)(3)(i)(B); 60.5775b(c)(3).

[37] *Id.* §§ 60.5740b(a)(1)(B), (a)(3)(i)(A); 60.5775b(c)(2).

[38] *Id.* §§ 60.5740b(a)(1)(A), (a)(4)(viii)(A); 60.5775b(c)(1).

[39] *Id.* § 60.5740b(a)(4)(viii)(A).

[40] *Id.* § 60.5850b(a) (excluding from the Proposed Rules natural gas fired stationary combustion turbines with that are equal to or less than 300 MW and that operate at an annual capacity factor less than or equal to 50 percent).

2032 (if the hydrogen option is selected)[41] or by 2035 (if the CCS option is selected).[42] As discussed in further detail in Sections IV.B and IV.C of these comments, neither of these technologies currently meets the legal standard under section 111 of the CAA that a system of emission reduction be adequately demonstrated or achievable. That leaves owners and operators of EGUs stuck between a rock and a hard place: they can either invest significant sums of money into unproven technologies or they can operate these units at half or less of their capacity and run the risk of there not being an adequate supply of electricity to serve their customers.

As EPA considers how to proceed on the Proposed Rules, it should coordinate and collaborate with its other peer agencies, such as DOE and FERC, to ensure that electricity remains reliable and affordable. Indeed, EPA and DOE recently entered into a Memorandum of Understanding ("MOU") that recognizes the importance of coordination between the two agencies "at a time of significant dynamism in the electric power sector."[43] EPA needs to follow the framework identified in the MOU and conduct an analysis of the effect of the Proposed Rules on reliability. Concerned that reliability issues have not been adequately analyzed in connection with the Proposed Rules, the Ranking Members of the Senate Committee on Energy and Natural Resources and the Committee on Environment and Public Works have also called on DOE to hold a series of technical conferences to analyze the impact of the Proposed Rules on electric reliability.[44]

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[41] *Id.* § 60.5740b(a)(4)(viii)(B).

[42] *Id.* § 60.5740b(a)(4)(viii)(C).

[43] DOE, EPA, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (Mar. 10, 2023); https://www.epa.gov/power-sector/electric-reliability-mou; *see also* DOE, Office of Policy, U.S. Department of Energy and Environmental Protection Agency Partner to Support Reliable Electricity: New Memorandum of Understanding Supports Reliability of Nation's Power System as Energy Sector Invests in Clean Energy Opportunities, https://www.energy.gov/policy/articles/us-department-energy-and-environmental-protection-agency-partner-support-reliable.

[44] Letter to FERC Chairman W. Phillips and Commissioners J. Danly, A. Clements, and M. Christie from Sen. J. Barrasso, Ranking Member, U.S. Senate Committee on Energy and Natural Resources

In addition, EPA needs to make sure that any final rule provides states with adequate time to consult with their power sector regulators, such as public service commissions, for the purpose of ensuring reliability and affordability. EPA should pay careful attention to comments filed by the regional transmission operators, independent system operators, regional reliability authorities, NERC, and state utility commissions regarding reliability.

Finally, EPA should consider providing a safety valve exemption for EGUs that adopt capacity factor restrictions in connection with these Proposed Rules that would allow those units to operate beyond those restrictions for the purpose of stabilizing the grid during periods of extreme load (such as during periods of excessive cold or heat or when baseload units go offline). EPA did this in the Clean Power Plan and should do so here.[45]

IV. The Proposed Rules Violate the Requirements of Section 111 of the CAA.

A. Legal Standard for Performance Standards under Section 111

Regulation of new sources in a source category under section 111(b) of the CAA is a prerequisite to regulation of existing sources under section 111(d). Section 111 of the CAA directs EPA to list categories of stationary sources that it determines contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.[46] After a source category has been listed by EPA, the Agency is required to establish NSPS for new and modified sources for the category pursuant to CAA section 111(b).[47] Once EPA has issued an NSPS pursuant to 111(b), in certain limited situations that exist with regard to GHG emissions from EGUs, EPA is then authorized to issue emission guidelines under section 111(d) that will guide states in setting

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and Sen. S.M. Capito, Ranking Member, U.S. Senate Committee on Environment and Public Works (June 30, 2023) (Attachment B to these comments).

[45] 80 Fed. Reg. 64,662, 64,877-79 (Oct. 23, 2015).

[46] CAA § 111(b)(1)(A), 42 U.S.C. § 7411(b)(1)(A).

[47] *Id.* § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B).

standards of performance for existing sources in the category.[48] EPA issued standards of performance for GHG emissions from new, modified, and reconstructed EGUs under section 111(b) in 2015.[49] The Subpart TTTT regulations cover both steam generating units and combustion turbines.[50] The Proposed Rules seek to revise the Subpart TTTT regulations and to establish section 111(d) emission regulations for both steam generating units and combustion turbines.[51]

For the purposes of section 111, a "standard of performance" is:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[52]

Under the plain language of the CAA, therefore, an NSPS must be "achievable" by the regulated new sources within the designated source category using the BSER that has been "adequately demonstrated" for the new sources to which the standard applies, considering cost and other factors. An NSPS must require an emission limitation on a continuous basis through establishment of a numerical emissions limit and a compliance protocol to measure those emissions. Only in

[48] *Id.* § 111(d)(1), 42 U.S.C. § 7411(d)(1).

[49] 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("Subpart TTTT").

[50] *Id.* Numerous parties filed petitions for review in the D.C. Circuit challenging the NSPS for steam generating units, which found partial CCS to be the best system of emission reduction ("BSER") for new steam generating units as being unlawful, while no one challenged the NSPS for combustion turbines. *See North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir.). This litigation has been stayed pending EPA's administrative review of the 2015 NSPS.

[51] EPA previously promulgated emission guidelines to address GHG emissions from existing EGUs in the Clean Power Plan (for both combustion turbines and steam generating units) and the Affordable Clean Energy Rule (for steam generating units only). Neither rule was ever implemented, as EPA discusses in the preamble to the Proposed Rules. 88 Fed. Reg. at 33,268-70, 33,271.

[52] CAA § 111(a)(1), 42 U.S.C. 7411(a)(1).

circumstances where it is not feasible to establish an enforceable numerical standard may EPA promulgate a design or work practice standard.[53]

In developing an NSPS for a type of new source, EPA must engage in a three-step analysis.[54] First, EPA identifies a system or systems of emission reduction that have been "adequately demonstrated" for that type of source. Second, EPA determines what emission levels are "achievable" by such sources using the adequately demonstrated system or systems.[55] Third, after this determination, EPA "must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations."[56] Although an NSPS must be based on the performance of BSER incorporated into the design of the type of source to which the standard applies, it may not require individual new sources to install or operate the particular technology or system identified as BSER to meet the numerical performance level established by the NSPS.[57]

1. "Adequately Demonstrated"

Any control technology selected as BSER must first be a technology that has been "adequately demonstrated."[58] The D.C. Circuit has held that a system that has been adequately demonstrated is "one which has been *shown* to be reasonably *reliable*, reasonably *efficient*, and which

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[53] *Id.* § 111(h), 42 U.S.C. § 7411(h).

[54] *See Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

[55] The "adequately demonstrated" and "achievable" criteria are separate and distinct requirements for an NSPS that apply to the selected control technology and the actual emission standard, respectively. "It is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

[56] *Id.*

[57] CAA § 111(b)(5), 42 U.S.C. § 7411(b)(5).

[58] EPA is further restricted under the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) ("EPAct") from considering in the "adequately demonstrated" determination technologies that receive certain types of funding from DOE and that receive certain types of tax credits.

can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly* in an economic or environmental way."[59] Thus, an adequately demonstrated system must have an operational history that shows more than mere technical feasibility: it must be dependable and effective, available at a reasonable cost for individual sources, and based on actual operating experience within the source category or at sufficiently similar sources.

Although EPA has some discretion to extrapolate from other industries in determining whether a technology demonstrated in one industry is adequately demonstrated for another industry, that discretion is significantly limited. EPA may look to a technology's performance in another industry only if experience in that context is sufficiently representative of operations of sources in the category to be regulated.[60] Any EPA extrapolations from one category to another are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture."[61] This latitude is further narrowed by the fact that NSPS are effective upon proposal and provide no "'lead time'" for further technological development.[62]

To be adequately demonstrated for all sources within a category or subcategory, a technology must be available for each source type to which the standard will apply. For example, in its 2005 proposed revisions to the NSPS for Subpart Da units, EPA rejected supercritical boiler design, integrated gasification combined cycle technology, and the use of clean fuels as potential bases for its revised standards due in part to the unavailability of these options across source types

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59 *Essex Chem. Corp.*, 486 F.2d at 433 (emphases added); *see also Nat. Res. Def. Council v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).

60 *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (per curiam).

61 *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); *see also id.* at 389 ("The essential question is whether the mandated standards can be met by a particular industry for which they are set, and this can typically be decided on the basis of information concerning that industry alone."); *Lignite Energy Council*, 198 F.3d at 934.

62 *Portland Cement Ass'n*, 486 F.2d at 391-92.

to which the standards would apply.[63] In assessing adequate demonstration, courts often consider issues such as whether: (i) sufficient implementation experience has accrued at full-scale facilities; (ii) data from prototype facilities or other industries are sufficiently representative to warrant extrapolation to the source category; (iii) experience has accrued with all fuel types; and (iv) unresolved issues remain regarding waste disposal or other harmful environmental effects.[64]

2. "Achievable"

Once EPA identifies an "adequately demonstrated" system, it then must determine what levels of emissions are "achievable" by individual sources applying that system. EPA must explain how the standard "is achievable under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur."[65] A standard that applies to all new sources in a category must be achievable "for the industry as a whole" and not just for a subset of sources.[66] As with determining whether a technology is adequately demonstrated, EPA may not base its determination that a standard is achievable on "mere speculation or conjecture."[67]

In order to show that a given emission level is "achievable" by a system of emission reduction, EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the

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[63] 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005).

[64] *See Lignite Energy Council*, 198 F.3d at 934; *Sierra Club*, 657 F.2d at 341 n.157; *Essex Chem. Corp.*, 486 F.2d at 438-39.

[65] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46, 433 (D.C. Cir. 1980).

[66] *Id.* at 431.

[67] *Lignite Energy Council*, 198 F.3d at 934.

standard."[68] In other words, the validity of EPA's achievability determination depends on how fully it has accounted for the variations among sources in the regulated category that could affect emission levels. Courts have repeatedly rejected NSPS that EPA deemed "achievable" based on test data from a narrow set of sample sources that did not represent the full range of relevant variability among sources to which the standard will apply.[69] In these cases, courts have required EPA to consider such variables as source type, feedstock or fuel type, the relationship between emissions generated and the effectiveness of control technology, and regional variations.[70] An NSPS "establishes what every source can achieve, not the best that a source could do."[71] It is intended to represent the "least common denominator" of control standards that can "be reasonably achieved by [a] new source *anywhere* in the nation."[72]

3. Consideration of Statutory Factors for "Best" Adequately Demonstrated System

After EPA has identified the emission levels achievable through the use of adequately demonstrated technology, the Agency selects a standard from the range of demonstrated technologies that "represents the best balance of economic, environmental, and energy considerations."[73] At this stage, in addition to the statutory factors of "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements,"[74] EPA

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[68] *Sierra Club*, 657 F.2d at 377 (quoting *Nat'l Lime Ass'n*, 627 F.2d at 433).

[69] *See, e.g.*, *Nat'l Lime Ass'n*, 627 F.2d at 432; *Portland Cement Ass'n*, 486 F.2d at 396, 402.

[70] *Nat'l Lime Ass'n*, 627 F.2d at 435-42.

[71] Letter from Gary McCutchen, Chief, New Source Review Section, EPA Office of Air Quality Planning and Standards, to Richard E. Grusnick, Chief, Air Division, Ala. Dep't of Envtl. Mgmt. at 1 (July 28, 1987), https://www.epa.gov/sites/production/files/2015-07/documents/crucial.pdf ("McCutchen Letter").

[72] *Id.* (emphasis added).

[73] *Sierra Club*, 657 F.2d at 330.

[74] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

may consider a proposed standard's projected emission reductions and its potential to encourage (rather than mandate) technological innovation.[75]

Moreover, in determining BSER, EPA must ensure that standards do "not give a competitive advantage to one State over another in attracting industry."[76] For example, in *Sierra Club*, the D.C. Circuit observed that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[77] Thus, the water intensive technology could not be selected as the BSER because it would have had the effect of precluding construction of new sources in states that lack the resources necessary (in this case, water) to allow compliance with the standard at a reasonable cost.

EPA must account for these factors at the plant level and may consider them "at the national and regional levels and over time."[78] The Agency's discretion, however, to consider costs and environmental or energy impacts at the national level does not permit it to disregard these impacts in selecting among the technologies that are demonstrated for individual sources. The D.C. Circuit made clear in *Sierra Club* that the CAA authorizes EPA to examine the national scale in addition to—not instead of—assessing a standard's impact on individual sources.[79] Thus, EPA may not set an NSPS based on national-scale considerations that would impose unreasonable costs, environmental impacts, or energy requirements at the level of individual plants.

EPA may not rely on consideration of costs and environmental or energy impacts on a national level to justify a standard of performance that is more stringent than would be permitted

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[75] *Sierra Club*, 657 F.2d at 326, 347.

[76] *Id.* at 325.

[77] *Id.* at 330.

[78] *Id.*

[79] *Id.*

based on source-level factors used to select among the demonstrated technologies. The CAA allows EPA to account for these impacts as a safety valve to prevent regulators from adopting standards of performance that cause more economic or environmental harm than they prevent, and not as a method for the Agency to demand additional emission reductions.[80] The Agency may consider these factors only after ruling out emission levels that are not achievable based on adequately demonstrated technology. Accordingly, EPA cannot rely on purported national or regional benefits to justify standards of performance that are unachievable, based on inadequately demonstrated technology, or otherwise unreasonable at the individual source level.

B. CCS Does Not Meet the Requirements of Section 111.

CCS is a promising technology that is making advancements through a variety of pilot projects throughout the United States. Some PGen members are actively investigating the feasibility of CCS at a portion of their facilities and hope to be able to rely on this technology in the future to reduce GHG emissions. While progress is being made, however, EPA is incorrect in its assertion that the technology has developed enough in the power sector to cross the regulatory threshold into being "adequately demonstrated," as required for any BSER under the CAA. There is insufficient experience at this time with CCS in commercial operation to find that the technology is currently feasible or reliable for widespread application in the electric generation industry—particularly at commercial scale and especially for utility combustion turbines where the technology has yet to be applied. Further, even if the technology were ready for more widespread deployment (which it is not), several issues remain that technological development cannot resolve, including geographical constraints, access to water, deficient pipeline infrastructure, parasitic load, and cost that prevent the technology from being properly selected as a BSER.

[80] *See, e.g.*, *id.*

EPA proposes that CCS be one of two BSERs identified for new base load stationary combustion turbines and for existing large and frequently used stationary combustion turbines.[81] The selection of CCS as a BSER for these EGUs violates section 111 of the CAA because it fails every prong of the three-step test for determining a BSER: (1) CCS is not adequately demonstrated at fossil fuel-fired EGUs; (2) any emission standard based on CCS at these EGUs is not achievable; and (3) even if CCS were adequately demonstrated and achievable for these EGUs (which it is not), it has numerous factors that prohibit its being considered "best." Each of these is discussed further below.

1. CCS Is Not Adequately Demonstrated at Fossil Fuel-Fired EGUs.

a. Combustion Turbines

EPA proposes to find CCS adequately demonstrated for use at natural gas combined cycle ("NGCC") combustion turbines based on two projects: the Bellingham Energy Center in Massachusetts, and the Peterhead Power Station in Scotland.[82] Neither of these projects supports that determination. At the Bellingham Energy Center, CCS was applied to an existing combined cycle turbine. The 40-megawatt ("MW") slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[83] A slipstream capture facility is not comparable to the amount of capture that is required at large fossil fuel-fired EGUs. Although the slipstream process arrangement is "a useful means for research and development," it "does not link the reliability of the host process to the CO_2 capture technology—

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[81] 88 Fed. Reg. at 33,288-316 (proposed BSER determination for new baseload stationary combustion turbines); *id.* at 33,362-69 (proposed BSER determination for existing large and frequently used stationary combustion turbines). The other BSER for base load combustion turbines is hydrogen co-firing, which PGen discusses *infra* in Section IV.C.

[82] *Id.* at 33,292.

[83] *Id.* Because this project involved utilization of the captured CO_2 onsite for use in the food industry, it did not involve any pipeline transport or storage component.

and thus cannot reflect the conditions for 24x7 utility power generation demonstration."[84] In addition, there are no data provided to describe the experience at Bellingham.[85] For example, it is not known whether operation was continuous or intermittent. As the Cichanowicz Technical Report notes, "[i]f periods of 85-95% CO_2 removal are interspersed with lower targets, this experience does not support BSER for utility application."[86]

The second project EPA relies on—the Peterhead Power Station in Scotland—"is in the planning stages of development" and is not yet in operation.[87] A plant that is not yet operational cannot serve as the basis for an adequately demonstrated determination because the technology has not yet "been shown to be reasonably reliable, reasonably efficient, and … reasonably … expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[88] To be considered as an adequately demonstrated technology, there must be an operational history that shows more than mere technical feasibility and the determination must be based on actual operating experience within the source category or at sufficiently similar sources.[89]

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[84] J.E. Cichanowicz, M.C. Hein, Technical Comments on New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule at 3 n.7 (Aug. 27, 2023) ("Cichanowicz Technical Report") (Attachment C to these comments).

[85] There is a DOE "fact sheet" on this project, but it only reports that the unit operated from 1991 to 2005 and that CO_2 removal of 85 to 95 percent was achieved. DOE, Carbon Capture Opportunities for Natural Gas Fired Power Systems, https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

[86] Cichanowicz Technical Report at 4.

[87] 88 Fed. Reg. at 33,292.

[88] *Essex Chem. Corp.*, 486 F.2d at 433; *see also NRDC v. Thomas*, 805 F.2d at 428 n.30.

[89] EPA also mentions "several *planned* projects using the NET Power Cycle" and "several *announced* commercial projects proposing to use the NET Power Cycle" in its discussion of adequate demonstration for CCS at combustion turbines. 88 Fed. Reg. at 33,292 (emphases added). These projects, none of which are in operation, cannot support an adequate demonstration determination.

EPA properly recognizes that the EPAct "constrained how the EPA could rely on [EPAct] assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111."[90] The specific language of EPAct that constrains EPA states that "[n]o technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [] for purposes of section 111 of the Clean Air Act."[91] Congress was clear. EPA may not base an adequately demonstrated determination on technologies that receive monies under EPAct. EPA is incorrect in its interpretation first set forth in the Clean Power Plan and restated in the Proposed Rules that it is "'not preclude[d] … from relying on the experience of such facilities in conjunction with other information.'"[92]

Seemingly recognizing this, EPA states that its adequately demonstrated determination does not rest on any EPAct funded technologies.[93] The Agency then goes on, however, to list eleven EPAct funded projects at stationary combustion turbines that it says "corroborate" its adequately demonstrated finding.[94] Even if these projects could be considered—which they cannot—they would not support an adequately demonstrated determination by EPA. All of these projects have one thing in common: none of them are actually constructed and in operation. EPA notes the following with regard to these projects: (1) General Electric project in Bucks, Alabama, "is *targeting* commercial deployment *by 2030*"; (2) Wood Environmental & Infrastructure Solutions in Blue Bell,

[90] *Id.* at 33,291.

[91] EPAct § 402(i), 42 U.S.C. § 15962(a). Similar EPAct language was codified in the Internal Revenue Code and restricts EPA from considering technology that received tax credits under the EPAct. EPAct § 1307(b), 26 U.S.C. § 48A(g); *see also* 88 Fed. Reg. at 33,291 n.240.

[92] 88 Fed. Reg. at 33,291 (quoting 80 Fed. Reg. at 64,541-42).

[93] *Id.* at 33,292.

[94] *Id.* at 33,292-93.

Pennsylvania, awarded funds "to complete an *engineering design study*" for a project that "*aim[s]* … to reduce CO_2 emissions by 95 percent … from several plants"; (3) General Electric Research in Niskayuna, New York, awarded funds to "*develop* a design to capture 95 percent of CO_2 from NGCC flue gas"; (4) SRI International in Menlo Park, California, awarded funds "to *design, build, and test* a technology that can capture at least 95 percent of CO_2"; (5) CORMETECH, Inc. in Charlotte, North Carolina, awarded funds "to further *develop, optimize, and test* a new, lower cost technology to capture CO_2 from NGCC flue gas and *improve scalability to large NGCC plants*"; (6) TDA Research, Inc. in Wheat Ridge, Colorado, awarded funds "to *build and test* a post-combustion capture process to *improve the performance* of NGCC flue gas CO_2 capture"; (7) GE Gas Power in Schenectady, New York, awarded funds "to *perform an engineering design study* to incorporate a 95 percent CO_2 capture solution for an existing NGCC site while *providing lower costs and scalability to other sites*"; (8) Electric Power Research Institute in Palo Alto, California, awarded funds "to *complete a study* to retrofit a 700-Mwe NGCC with a carbon capture system to capture 95 percent of CO_2"; (9) Gas Technology Institute in Des Plaines, Illinois, awarded funds "to *develop membrane technology* capable of capturing more than 97 percent of NGCC CO_2 flue gas"; (10) RTI International in Research Triangle Park, North Carolina, awarded funds "to *test a novel* non-aqueous solvent *technology*"; and (11) Tampa Electric Company in Tampa, Florida, awarded money "to *conduct a study* retrofitting" one of its plants "with post-combustion CO_2 capture technology *aiming* to achieve a 95 percent capture rate."[95] None of these studies and tests can support a determination by EPA that CCS is currently adequately demonstrated as a system of emission reduction for stationary combustion turbines—either at new EGUs or existing EGUs.

[95] *Id.* at 33,293 (emphases added).

EPA's determination that CCS is adequately demonstrated for new and existing combustion turbines is not grounded in any actual experience with this technology at these types of EGUs. EPA's proposed determination is unlawful because it is "based on 'crystal ball' inquiry"[96] and "mere speculation or conjecture."[97]

b. Steam Generating Units

EPA proposes to find CCS adequately demonstrated for use at existing coal-fired steam generating units and proposes this technology with 90 percent capture of CO_2 as the BSER for long-term coal-fired steam generating units and for large modifications at those units.[98] EPA's finding is based on a single project at a coal-fired steam generating unit (SaskPower's Boundary Dam Unit 3 project in Saskatchewan, Canada), two slipstream power plant projects (AES Warrior Run and AES Shady Point), and two industrial applications (the Searles Valley Minerals Soda Ash Plant and the Quest CO_2 capture facility).[99] As discussed below, these projects do not support EPA's determination.

There is only one CCS project operating in North America that is relevant to utility power generation: the SaskPower Boundary Dam Unit 3 project in Saskatchewan, Canada. The Boundary Dam project has had technical difficulties and has been underperforming.[100] In 2021, the plant captured 43 percent less CO_2 than it had the year before. SaskPower attributed this decrease to "challenges with the main CO_2 compressor motor" that forced the CCS part of the plant to go

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[96] *Portland Cement*, 486 F.2d at 391.

[97] *Lignite Energy Council*, 198 F.3d at 934.

[98] 88 Fed. Reg. at 33,346-51.

[99] *Id.* at 33,291-92, 33,346-47.

[100] *See* J.P. Kay, et al., Energy & Environmental Research Center, University of North Dakota, Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60 at 6-7 (Aug. 2023) ("EERC Report") (Attachment D to these comments).

offline for multiple months in 2021.[101] The company's data for 2021 show that the CCS facility is capturing only approximately 44 percent of its 90 percent maximum capacity—meaning more than half of the plant's CO_2 emissions are not being captured.[102] And, more importantly, meaning that EPA's proposed 90 percent capture that is part of its BSER determination for coal-fired steam generating units is not being achieved. In addition, Boundary Dam Unit 3 is relatively small—only 110 MW—and therefore is not representative of how CCS might work at a much larger scale. This is particularly important given that CCS is BSER only for long-term coal-fired steam generating units (i.e., those that will operate after January 1, 2040) and for coal-fired steam generating units that undergo a large modification. Owners and operators of coal-fired steam generating units will only be willing to invest the sums of money needed for CCS (or for a large modification) in large units that are run frequently and are needed for base load generation. Therefore, a 110 MW unit is not representative of the scale that will be needed under the Proposed Rules.

The other two power projects cited by EPA in its proposed adequately demonstrated finding are slipstream projects: AES Warrior Run and AES Shady Point. While the slipstream process arrangement is "a useful means for research and development," it "does not link the reliability of the host process to the CO_2 capture technology—and thus cannot reflect the conditions for 24x7 utility power generation demonstration."[103] Neither of these projects is anywhere close to capturing 90 percent of the CO_2 from the unit. Warrior Run, which is a 205 MW unit, captures only 10 percent of

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[101] E&E News, Energy Wire, *CCS 'red flag?' World's sole coal project hits snag* (Jan. 10, 2022), https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/.

[102] *Id.*

[103] Cichanowicz Technical Report at 3 n.7; EERC Report at 5 ("[T]he small capacity, slipstream system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines.").

its CO_2 emissions and sells them to the food and beverage industry.[104] Shady Point, which is a 350 MW unit, captures even less of its CO_2—5 percent.[105]

EPA relies on two industrial units for the remainder of its adequately demonstrated determination. These units are the Searles Valley Minerals Soda Ash Plant in Trona, California, and the Quest CO_2 capture facility in Alberta, Canada. Neither of these facilities represent large-scale utility duty. In addition, there is no evidence that either of these projects were able to achieve 90 percent capture of CO_2. EPA notes in the Proposed Rules that the Searles Valley Minerals plant captures 270,000 metric tons of CO_2 per year—but does not provide information on what percentage of emissions this represents.[106] Publicly available information shows that 800 tons per day are captured at the project, and experts note that this implies no more than a 33 percent removal rate from the smallest unit at the plant for a complete 24-hour day.[107] The Quest facility involves CCS retrofitted to three existing steam methane reformers.[108] EPA states that the Quest facility captures approximately 80 percent of the CO_2 in the produced syngas.[109] The EERC Report notes the obvious, however: "[T]he overall capture of the facility falls short of EPA's proposed 90% minimum capture rate."[110] Moreover, the Cichanowicz Technical Report notes, "[t]he effluent from this methane reforming process does not reflect combustion products, as CO2 content is elevated

[104] 88 Fed. Reg. at 33,292.

[105] *Id.*

[106] *Id.*

[107] Cichanowicz Technical Report at 3. The EERC Report estimates the capture rate to approximate 18 percent. EERC Report at 5. Either way, this is a far cry from the 90 percent capture rate EPA arbitrarily crystal-balls.

[108] 88 Fed. Reg. at 33,292.

[109] *Id.*

[110] EERC Report at 6.

compared to utility application," and while this "contribut[es] to general CCUS knowledge," it "is not a basis to designate CCUS as BSER for utility application."[111]

EPA also cites some projects as "further corroborat[ion]" that it says it did not consider as part of its adequately demonstrated analysis because of EPAct funding.[112] Even if these projects could be considered by EPA in its adequately demonstrated determination—which they cannot—they do not support EPA's proposed finding. The most notable of these EPAct projects is the Petra Nova project near Houston, Texas. The Petra Nova project, which is another slipstream project, has encountered problems. The plant, which began operation in January 2017, was designed to capture 33 percent of the CO_2 emissions from one of the units at the W.A. Parish facility. The facility missed this target by about 17 percent, capturing 3.8 million short tons of CO_2 during its first three years of operation, which was less than the 4.6 million short tons that had been expected to be captured.[113] During the time the facility operated, it experienced outages on 367 days, with the CCS facility accounting for more than one-fourth of those outages.[114] The project was also dependent on oil prices to be economically viable. The project was "impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil," and its owner at the time, NRG, placed the Petra Nova project in reserve shutdown status on May 1, 2020.[115] The Petra Nova project had "no alternate method of sequestration. Market-driven EOR alone does not adequately

[111] Cichanowicz Technical Report at 3.

[112] 88 Fed. Reg. at 33,292-93.

[113] Reuters, *Problems plagued U.S. CO_2 capture project before shutdown: document* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8.

[114] *Id.*

[115] NRG, Coal: Examining how we use Earth's oldest resource, https://www.nrg.com/generation/coal.html.

demonstrate CCS that will meet EPA's proposed continuous emission reduction."[116] The project, which has not operated since that time, has been sold, and the new owners have indicated plans to bring it back online later this year.[117]

EPA also mentions Plant Barry in Mobile, Alabama, which is another slipstream project on a coal-fired unit that tested a CCS unit at a 25 MW scale.[118] The size of this unit is quite small and is not a demonstration of the technology at commercial scale.

EPA's proposed determination that CCS is adequately demonstrated for modified and existing coal-fired steam generating units is unlawful because it is "based on 'crystal ball' inquiry"[119] and "mere speculation or conjecture."[120] There is no evidence that CCS technology can capture 90 percent of the CO_2 emissions from a facility that is not a slipstream facility and do so on a consistent basis. Moreover, there is no evidence that these technologies can work on large, commercial-scale EGUs.

2. EPA's Proposed NSPS for New and Modified Fossil-Fuel Fired EGUs and Presumptively Approvable Emission Limitations for Existing Fossil Fuel-Fired EGUs that Are Based on CCS Technology Are Not Achievable.

EPA has long held the position that a standard of performance under section 111 "establishes what *every* source can achieve" and is intended to represent the "least common denominator" that can "be reasonably achieved by [a] new source *anywhere* in the nation."[121] This long-held position also applies to emission guidelines for existing sources under section 111(d) of

[116] EERC Report at 6.

[117] *See* 88 Fed. Reg. at 33,293 & n.258 (citing a news article to note that "there are reports of plans to restart the capture system").

[118] *Id.* at 33,293.

[119] *Portland Cement*, 486 F.2d at 391.

[120] *Lignite Energy Council*, 198 F.3d at 934.

[121] McCutchen Letter at 1 (emphases added).

the CAA where EPA establishes the BSER and sets presumptively approvable performance standards for those sources. In the Proposed Rules, EPA proposes NSPS based on a BSER of use of CCS with 90 percent capture of CO_2 for new NGCC combustion turbines[122] and for modified steam generating units.[123] EPA also proposes presumptively approvable performance standards based on a BSER of use of CCS with 90 percent capture of CO_2 for existing coal-fired steam generating units that will operate after January 1, 2040,[124] and as a BSER option for existing large, frequently used combustion turbines.[125] These proposed NSPS and presumptively approvable emission limitations fail to meet the requirements under section 111 that a standard of performance be achievable "for the industry as a whole."[126]

As EPA admits in the Proposed Rule, many areas of the country do not have ready access to geologic storage for CCS. Indeed, EPA "found that there are 43 States containing areas within 100 kilometers ("km") [62 miles] from currently assessed onshore and offshore storage resources…."[127] For EGUs not immediately near a geologic storage site, the construction of a pipeline to transport the captured CO_2 is necessary in order for the performance standard to be achievable. But the cost to construct a pipeline is very expensive, permitting is a years-long process, and pipelines are met with increasing resistance making permitting in many cases impossible.[128] Indeed, some PGen

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[122] 88 Fed. Reg. at 33,325, Table 3.

[123] *Id.* at 33,335.

[124] *Id.* at 33,359, Table 5.

[125] *Id.* at 33,366-69.

[126] *National Lime*, 627 F.2d at 431.

[127] 88 Fed. Reg. at 33,298. The EERC moreover shows that EPA's assessment of suitable geologic sequestration site availability is incorrect and that, based on the U.S. Geological Survey ("USGS"), "more and longer pipelines will be needed to transport captured CO_2 to feasible storage locations." EERC Report at 9.

[128] *See, e.g.*, I. Penn, NY TIMES, *Atlantic Coast Pipeline Canceled as Delays and Costs Mount* (July 5, 2020), https://www.nytimes.com/2020/07/05/business/atlantic-coast-pipeline-cancel-dominion-energy-berkshire-hathaway.html; C. Davenport, NY TIMES, *Mountain Valley Pipeline Halted as Legal Wrangling*

members have experienced pipeline construction costs in the range of $4 to $10 million per mile. Under EPA's own facts, this means that in 7 States, the owners and operators of EGUs will need to construct a pipeline that is at least 62 miles long—with a *starting* cost ranging between $248 and $620 million dollars that will only increase with every additional mile.

EPA's "solution" to this achievability problem is to suggest that "States that may not have geologic sequestration sites may be served by new generation, including new base load combustion turbines, built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines."[129] While this might be conceivable for new EGUs, it is faulty on two levels. First, constructing transmission lines is also expensive, takes years to permit, and is often met with public resistance.[130] Second, and more importantly, this "give[s] a competitive advantage to one State over another in attracting industry," in violation of section 111.[131] And this "solution" is completely unworkable for existing EGUs, unless the owner or operator wants to prematurely retire an EGU and construct a new one near geologic storage—leading to a state without geologic storage being harmed twice (once when a plant in its borders closes and again when the new construction takes place in another state).

Heats Up (July 12, 2023), https://www.nytimes.com/2023/07/12/climate/mountain-valley-pipeline-courts.html; A. Liptak and A. VanSickle, NY TIMES, *Supreme Court Clears the Way for Pipeline as Appeal Moves Forward* (July 27, 2023), https://www.nytimes.com/2023/07/27/us/supreme-court-mountain-valley-pipeline.html; *see also* W. Morris and J. Weeda, Analysis of Post Combustion CO_2 Capture, Transport and Storage Costs in the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule at 4 (Aug. 3, 2023) ("Morris CCS Report") (Attachment E to these comments).

[129] 88 Fed. Reg. at 33,298.

[130] J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives at 6 (Aug. 3, 2023) ("The experience of the utility sector in recent years shows that building transmission is a challenging multi-year process, and in the more populated areas, it can be nearly impossible.") ("Weeda Report") (Attachment F to these comments).

[131] *Sierra Club*, 657 F.2d at 325.

A recent Congressional Research Service report found that there are currently approximately 5,000 miles of pipelines in the United States to transport CO_2.[132] But this is an infinitesimal fraction of what is needed. That report found that a recent study suggests that to achieve national goals for GHG reduction would require an additional 66,000 miles of pipelines by 2050, at a cost of "some $170 billion in new capital investment."[133] EPA glosses over the difficulties and hurdles involved in constructing this pipeline network in the Proposed Rules. The Agency also glosses over safety issues for these pipelines, noting almost as an aside that there was a failure of a CO_2 pipeline in Satartia, Mississippi in 2020 and that the Pipeline Hazardous Materials Safety Administration is conducting a rulemaking on safety issues.[134] No mention is made of whether this rulemaking has concluded. Rather, EPA states in a conclusory fashion that state and federal pipeline safety standards "ensure that captured CO_2 will be securely conveyed to a sequestration site."[135]

In addition, as discussed above, there is only one coal-fired steam generating unit that comes close to meeting a 90 percent capture rate, and that unit has been plagued with issues and does not reliably meet that capture rate. And there are no gas-fired combustion turbines employing CCS at all.

For all these reasons, EPA's determination that CCS with a 90 percent capture rate is achievable across the nation as a whole is arbitrary, capricious, and unlawful.

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[132] Congressional Research Service, Carbon Dioxide Pipelines: Safety Issues at 1 (June 3, 2022), https://crsreports.congress.gov/product/pdf/IN/IN11944.

[133] *Id.*

[134] 88 Fed. Reg. at 33,294.

[135] *Id.*

3. CCS Has Many Obstacles that Prevent it From Being Considered as a "Best" System to Reduce GHG Emissions from Fossil Fuel-Fired EGUs.

CCS cannot be considered the BSER for fossil fuel-fired EGUs because CCS "give[s] a competitive advantage to one State over another"[136] due to the lack of geological storage across the nation, the fact that CCS is a water intensive technology that has a large parasitic load, and the fact that it imposes unreasonable costs at the level of individual plants.[137]

a. Geographic and Site Limitations

CCS technology is distinct from other emission controls in that its application requires that suitable geological formations for underground storage of captured CO_2, such as deep saline reservoirs, or CO_2 transport pipelines be available nearby. The reality is, however, that many parts of the country have no assessed capacity for CO_2 storage, and even those that do may not be adequate for large-scale CO_2 sequestration when examined on a site-by-site basis.

As shown by DOE and USGS surveys, potential repository sites are not evenly distributed throughout the United States, and many locations throughout the country lack suitable geological conditions for carbon storage.[138] The USGS National Assessment concludes that fully two-thirds of the technically accessible storage resources in the United States are confined to the Coastal Plains region, with 91 percent of that total limited to a single basin.[139] Another tenth of the nation's

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[136] *Sierra Club*, 657 F.2d at 325.

[137] *Id.* at 330.

[138] *See* U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Storage Atlas and Data Resources*, https://netl.doe.gov/carbon-management/carbon-storage/atlas-data ("NETL Carbon Storage Atlas"); U.S. Department of the Interior, U.S. Geological Survey, Circular 1386, Version 1.1, *National Assessment of Geologic Carbon Dioxide Storage Resources—Results* (Sept. 2013), https://pubs.usgs.gov/circ/1386/pdf/circular1386_508.pdf ("USGS National Assessment").

[139] USGS National Assessment at 3 (Fig. 1), 15.

potential storage capacity is in Alaska, almost all of which is confined to the remote North Slope.[140] In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard, contains less than 1 percent of the nation's storage capacity.[141]

Moreover, the CO_2 storage at any specific site will not be known until the site is assessed for specific criteria. As DOE noted in the first edition of its North American Carbon Storage Atlas, "[i]t is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and that no major faults exist."[142] The North American Carbon Storage Atlas also cites the importance of documenting the CO_2 storage capacity, the "injectivity," and the ability of the porous rock to permanently trap CO_2. All of these criteria are necessary to evaluate the storage potential of a site.[143] Other site-specific items that need to be considered include land-management, regulatory restrictions, and whether the basin contains freshwater that would restrict its use for CO_2 storage.[144]

Furthermore, the estimates presented in the DOE and USGS reports are uncertain, "high level" assessments of potential storage resources, and actual storage capacity is likely to be significantly lower than the estimates presented in these studies. USGS researchers have expressed concern that due to issues such as reservoir pressure limitations, boundaries on migration of CO_2, and acceptable injection rates over time, "it is likely that only a fraction" of the high-level estimated

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[140] *Id.*

[141] *Id.* at 3 (Fig 1).

[142] *The North American Carbon Storage Atlas – 2012* (First Edition), Slide 18, https://www.slideshare.net/dove000/nacsa2012webversion-43472232 ("North American Carbon Storage Atlas").

[143] *Id.*

[144] USGS National Assessment at 15.

technically accessible CO_2 storage resources could be available.[145] A formation may have one or more fractures in the caprock or may have well penetrations. A site may have sufficient porosity but low permeability. Current information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to determine how the CO_2 plume will spread and to address displacement of underground fluids. Settlement of CO_2 and displacement of underground fluids factor into the property rights that must be pre-arranged for sequestration. These critical issues require costly, potentially time-consuming research and resolution that takes several years; it can take several years simply to evaluate a site for CO_2 storage potential. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to begin the process all over again with additional time and money.

For example, in the late 2000s, several entities (including PGen members) participated in a CO_2 storage pilot project to investigate the suitability of a formation in the Colorado Plateau region of northeastern Arizona.[146] Five candidate project sites were evaluated prior to the selection of a final test site near Holbrook, Arizona. The project participants held meetings to inform the local community about the project beginning in 2007, obtained the necessary state and federal permits for well drilling and CO_2 injection in 2008-2009, and completed the 3,800 foot well in 2009. After investing over $5.7 million and several years on the project, the participants found that the

[145] *See* Steven T. Anderson, *Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review*, 26:2 NATIONAL RESOURCES RESEARCH 137-59 (Apr. 2017), https://link.springer.com/article/10.1007/s11053-016-9310-7; Steven T. Anderson, *Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review*, 26:1 Natural Resources Research 89-112 (Jan. 2017), https://link.springer.com/article/10.1007/s11053-016-9303-6.

[146] DOE provided 80.5 percent of the overall funding for this project. *See* West Coast Regional Carbon Sequestration Partnership ("WESTCARB"), *Factsheet for Partnership Field Validation Test (Rev. 10-28-09)* at 5, http://www.westcarb.org/pdfs/FACTSHEET_AZPilot.pdf.

geological formation had insufficient permeability to proceed with CO_2 injection, and the project was discontinued.[147]

Suitable sites for EOR are similarly limited and uncertain. EOR sites are unevenly distributed across the country. DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration.[148] Moreover, as with sequestration, several years of subsurface feature characterization may be required before a site can be assessed as suitable for EOR. These limits are particularly significant because the only commercial utility applications of CCS to date that could be cost-justified have had to rely on EOR. The reliance on EOR, however, renders the operation volatile—as can be seen from the Petra Nova project in Texas, which ceased operations because of an economic downturn at the beginning of the COVID-19 pandemic.[149]

In addition, the lack of availability of the needed geographic criteria cannot be easily solved by the construction of pipelines to move the separated gas to areas of the country that can store the CO_2. There are many hurdles to pipeline construction. First, it is extremely expensive; current pipeline projects have cost between $4 to10 million per mile of pipe. Second, pipeline projects face

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[147] *See* WESTCARB, "Arizona Utilities CO_2 Storage Pilot—Cholla Site," http://www.westcarb.org/AZ_pilot_cholla.html.

[148] North American Carbon Storage Atlas at 25 (estimating that 250 billion tons of CO_2 can be used for EOR and thus stored, which is about 10 percent of the capacity estimated for deep saline sequestration).

[149] *See* NRG, Coal: Examining how we use Earth's oldest resource, https://www.nrg.com/generation/coal.html (noting that the plant "has been impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil" and that "[g]iven the state of oil markets, in May 2020 the carbon capture facility was placed in reserve shutdown status to allow it to be brought back online when economic conditions improve").

significant opposition from the public and require extensive permitting that is not easily or quickly obtained.[150]

Finally, even if there is a way to store the separated CO_2 (either onsite or by pipeline to a suitable site), CCS may not be able to be installed on an existing EGU because of space constraints at the plant. A carbon capture facility is big and requires a very large amount of land to be available for its construction. Many existing EGUs do not have the land available at the plant to construct the carbon capture facility, particularly in urban areas.

b. Water Constraints

It is well recognized that CCS requires significant water for process operation. As EPA has acknowledged, "[a]ll CCS systems that are currently available require substantial amounts of water to operate," which "limit[s] the geographic availability of potential future CCS construction to areas of the country with sufficient water resources."[151] Like sequestration, water resources for use in CCS are severely limited in some parts of the country.

EPA acknowledges that CCS increases water consumption at an EGU. For coal-fired steam generating units, EPA estimates an increase in water consumption of 36 percent gross.[152] EPA glosses over this fact and notes that a feasibility study for a project by SaskPower "would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption." Citation to a *feasibility study* that plans on trying something for the first time does not solve the present problem. Neither is the problem solved by using "dry or hybrid cooling systems" in "[r]egions with limited water supply," as EPA suggests, while simultaneously

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[150] Any flexibilities that can be provided through the National Environmental Policy Act process to expedite permitting of projects would be useful for compliance with EPA's GHG reduction programs under section 111.

[151] 83 Fed. Reg. 65,424, 65,443 (Dec. 20, 2018); *see also generally id.* at 65,442-44.

[152] 88 Fed. Reg. at 33,350.

acknowledging that "wet cooling systems [are] more effective."[153] EPA then without anything more concludes that it "is proposing that the water use … requirements are manageable and therefore the EPA does not expect any of these considerations to preclude coal-fired power plants generally from being able to install and operate CCS."[154] Acknowledging a problem exists, pointing to a feasibility study for new technology not yet in operation, and noting possible alternatives that are not as effective do not form the basis for a conclusion that the problem is manageable. EPA's conclusion is arbitrary and capricious, and therefore unlawful.

EPA fares no better with regard to water issues resulting from CCS use at gas-fired combustion turbines. There, EPA acknowledges that CCS use at a combined cycle combustion turbine results in "an increase of about 50 percent" in water use.[155] Yet, EPA concludes that "because NGCC units require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS does not present unsurmountable concerns."[156] EPA also notes that "many NGCC units currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water."[157] There is no analysis beyond this. For example, there is no discussion of whether CCS can use dry cooling technologies, whether they have been used at NGCC units with CCS (which would be impossible since CCS has never been employed at an NGCC), or how effective those technologies might be. Nor is there any analysis of how a 50 percent increase in water use affects

[153] *Id.*

[154] *Id.*

[155] *Id.* at 33,302.

[156] *Id.*

[157] *Id.*

arid areas of the country. More analysis is required to support EPA's conclusion. As proposed, EPA's conclusion is unsupported, arbitrary, and capricious.

The D.C. Circuit has previously found that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[158] Therefore, the court concluded that a water intensive technology could not be selected as the BSER under section 111 because it would have the effect of precluding construction of new sources in states that lack the resources necessary (here, water) to allow compliance with the standard at a reasonable cost.[159] EPA has not explained why the court's reasoning in that case does not apply here. EPA's conclusory proposed findings that water will not be a barrier to the deployment of CCS at coal-fired steam generating units and at NGCC combustion turbines violate section 111.

c. Parasitic Load

There is a significant parasitic load associated with the operation of CCS equipment. EPA estimates the operation of CCS equipment at a new 500 MW NGCC EGU will de-rate the plant by 11 percent to a 444 MW plant.[160] For coal-fired steam generating units, EPA estimates that the CCS equipment would reduce the output at a 474 MW-net (501 MW-gross) coal-fired steam generating unit by 23 percent to a 425 MW-net unit.[161] For NGCC units, EPA recommends that a developer simply build a larger NGCC plant to compensate for the parasitic load and proposes to find that "[a]lthough the use of CCS imposes additional energy demands on the affected units, those units are

[158] *Sierra Club*, 657 F.2d at 330.

[159] *Id.*

[160] 88 Fed. Reg. at 33,302.

[161] *Id.* at 33,349.

able to accommodate those demands by scaling larger, as needed."[162] This recommendation and conclusion fails to consider the effect of CCS on existing large, frequently used NGCCs. EPA's failure to examine the effect of the energy penalty from CCS on those existing units is arbitrary and capricious.

EPA does not make any recommendation for existing coal-fired steam generating units; for those units, EPA simply proposes to find "that the energy penalty is relatively minor compared to the GHG benefits of CCS and, therefore, does not disqualify CCS as being considered the BSER for existing coal-fired steam generating units."[163] EPA's analysis misses the mark. The parasitic load associated with CCS is not minor: it amounts to 25 to 30 percent.[164] As discussed above in Section III, the energy transition has resulted in the electricity grid in the United States becoming strained, with reliability being increasingly threatened. Installing CCS on existing fossil fuel-fired EGUs will exacerbate this reliability problem because a large percentage of the energy being generated will now be needed to power the CCS technology at power plants rather than being available to the consumer. EPA needs to consider the effect of CCS on electric reliability, which it has not done.[165] Failure "to consider [this] important aspect of the problem" is arbitrary and capricious.[166]

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[162] *Id.* at 33,302.

[163] *Id.* at 33,349.

[164] D. Walsh, Analysis of EPA's Proposed Construction Timeframes for CCS Projects at 4 (Aug. 3, 2023) ("Walsh Report") (Attachment G to these comments).

[165] *Id.* ("EPA has failed to address the resource adequacy challenges that will occur when fossil generation sites accept a 25%-30% parasitic load loss to run an associated CCS site."). The alternative of "add[ing] onsite generation to run the CCS plant" does not solve the problem. This just triggers "[New Source Review] and additional air permitting requirements that are federal, state, and local based may add an additional 24-36 months prior to commencing construction" and would also be costly. *Id.*

[166] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

d. Cost

CCS is an expensive technology, particularly for existing plants. EPA underestimates the cost of CCS and overestimates the impact of the IRA, thus severely distorting the cost impact of this technology.[167] EPA in its cost estimates relies heavily on the costing methodology developed by the National Energy Technology Laboratory (NETL), but it ignores the limitations of this methodology.[168] In short, the NETL methodology is appropriate for comparing alternatives, but it does not seek to estimate the full cost of a project. Indeed, comparing NETL methodology to the "full cost" methodology employed by the EIA (and executed by a company that often works EPA, including in this rulemaking, Sargent & Lundy) yields a difference of 168 percent (i.e., for a 650 MW supercritical unit, the NETL estimate is $3,482/kw whereas the Sargent & Lundy EIA estimate is $5,876/kw).[169]

Congress recently made numerous changes to Section 45Q of the Internal Revenue Code in the IRA that have the effect of increasing the tax credits available for carbon sequestration. Under the IRA, projects that are placed in service after December 31, 2022, may receive a credit of $85 per ton for CO_2 disposed of in secure geologic storage and $60 per ton of CO_2 used for EOR and disposed of in secure geologic storage or utilized in a qualified manner.[170] This is a significant increase from the amounts previously available for units placed in service before 2023.

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[167] EPA should consider analyzing the cost of CCS (and hydrogen co-firing) without the IRA. The presence of the IRA in EPA's current analysis masks the costs that would occur if IRA support fails to materialize.

[168] D. Campbell, Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy at 2 (Aug. 3, 2023) ("Campbell NETL Cost Report") (Attachment H to these comments).

[169] *Id.* at 9.

[170] Pub. L. No. 117-169, § 13104(c).

While these additional tax credits should help mitigate the cost issue, there remains significant risk associated with CCS construction. The Section 45Q tax credits available through the IRA may be taken *only* if the facility is able to capture a minimum amount of CO_2. An electric generating facility must capture at least 18,750 tons of CO_2 per year and have a capture design capacity that is at least 75 percent of the unit's baseline carbon oxide production.[171] Because of the current nascent state of the technology, there is risk that the technology may not work, and if that occurs, then the EGU will not be eligible to receive the tax credits that help offset some of the significant costs.

Moreover, as Dr. William Morris explains, "the assumption that the credit is directly paid and instantaneous shows that the EPA misunderstands (or misrepresents) basic tax law or financial modeling."[172] Indeed, the flaws in EPA's consideration of cost for CCS systems are many:

> The EPA has not sufficiently modeled the cost of CCS implementation, nor has the EPA sufficiently modeled the impacts of adding CCS to the existing fleet in terms of grid impacts, cycling capabilities to meet the needs of an increasing renewable energy penetration grid, water use and impacts, and technological readiness.
>
> The EPA should perform an adequate analysis to determine how the technology required will impact the operation of the grid, and what it will cost in a variety of regions throughout the country, all of which will be significantly impacted by this regulation.
>
> Instead, the EPA has used fundamentally flawed models which do not use consistent baseline assumptions. Their assumptions use conflicting costs for CO_2 transportation, storage, and monitoring. The assumptions use capacity factors that are not reflected in the actual capacity factor data from the EIA, extrapolate the least cost construction environments to the entire United States without any acknowledgment of how location substantially impacts costs, completely misrepresent the impact of the 45Q tax credit in financial modeling, and provide conflicting examples of BSER projects, which

[171] *Id.* § 13104(a).

[172] Morris CCS Report at 8.

> would likely not even comply with the proposed rule as justification for the rule.[173]

C. Hydrogen Co-Firing at Natural Gas-Fired Combustion Turbines Does Not Meet the Requirements of Section 111 of the CAA and Impermissibly "Redefines" the Source.

Hydrogen combustion is another promising technology that is not yet ready to be deployed throughout the industry as a system of emission reduction. There are many hurdles that need to be overcome before that can be the case, including EGUs being able to combust large amounts of hydrogen for extended periods of time, a ready-supply of hydrogen, an ability to transport the hydrogen, and an ability to store the hydrogen. As discussed further below, none of these hurdles have yet been overcome, and EPA's wishful thinking that all of these things will fall into place by 2032 are "wispy hopes based on no evidence at all."[174]

EPA proposes that one of the BSER options for new and existing combustion turbines in certain subcategories is the co-firing of low-GHG hydrogen, first at a level of 30 percent beginning in 2032 and second at a level of 96 percent beginning in 2038.[175] As an initial matter, the very fact that EPA phases the proposed standards for hydrogen co-firing over 15 years, with one BSER level that would apply in eight years and the second in fifteen years, demonstrates that at least the latter is not adequately demonstrated and is certainly not achievable at this time. (In fact, it would not even be achievable in 2032, by EPA's own admission.) Indeed, neither BSER levels (30 percent or 96 percent) is adequately demonstrated or achievable. EPA's determination that hydrogen co-firing is a BSER option for new NGCC units and for existing large and frequently used NGCC units is incorrect and violates section 111 of the CAA. In addition, co-firing hydrogen improperly

[173] *Id.* at 10.

[174] *NRDC v. Thomas*, 805 F.2d at 432.

[175] 88 Fed. Reg. at 33,325 (Tables 3 and 4), 33,363-66.

"redefines" the source, in violation of the CAA. For the reasons outlined below, EPA should not finalize its proposal for hydrogen co-firing.

1. The Ability of Combustion Turbines to Combust Hydrogen at the Levels Contemplated by EPA and Over an Extended Period of Time Is Not Adequately Demonstrated.

The ability of combustion turbines to co-fire hydrogen at either the 30 percent or the 96 percent levels over an extended period of time is not adequately demonstrated. As EPA acknowledges, "utility combustion turbines have only recently begun to co-fire smaller amounts of hydrogen as a fuel to generate electricity" and "[t]he industrial combustion turbines currently burning hydrogen are smaller than the larger utility combustion turbines…."[176]

At this time, the most hydrogen that an NGCC has been able to combust is 44 percent—and most units are much lower than that.[177] There are also significant increases in NOx emissions associated with hydrogen combustion (increases of approximately 24 percent) that offset some of the benefits of reduced CO_2 emissions.[178] EPA's response to these issues is to point to the fact that "the major combustion turbine manufacturers *are designing* combustion turbines that will be capable of combusting 100 percent hydrogen by 2030" and to state that these "*goals* of equipment manufacturers," combined with the ability of existing combustion turbines to combust hydrogen at lower levels than proposed supports a determination that the technology to combust 30 percent

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[176] *Id.* at 33,311.

[177] Utility Dive, *NYPA burns up to 44% green hydrogen in GE turbine in first such retrofit of a US natural gas plant* (Sept. 23, 2022), https://www.utilitydive.com/news/new-york-power-authority-burns-green-hydrogen-cuts-emissions-EPRI-GE-Airgas-NYPA/632527/.

[178] Clean Energy Group, *Hydrogen Hype in the Air* (Dec. 14, 2020), https://www.cleanegroup.org/hydrogen-hype-in-the-air/ (noting two European studies that have found that combusting "hydrogen-enriched natural gas in an industrial setting can lead to NOx emissions up to *six times that of methane*" (emphasis in original)); *see also* Kiewit Engineering Group, Inc., Technical Comments on Hydrogen and Ammonia Firing § 2.4, at 18 (Aug. 4, 2023) ("Kiewit Report") (Attachment I to these comments); Hydrogen Cofiring Demonstration at 2-3.

hydrogen by 2032 and 96 percent hydrogen by 2038 is adequately demonstrated.[179] However, Kiewit Engineering Group ("Kiewit"), one of the largest construction companies and engineering organizations in North America—indeed, one that is involved in current hydrogen projects—calls the manufacturers' goals of achieving 100 percent hydrogen firing by 2030 "aspirations."[180] Kiewit notes there are "major obstacles to overcome before those aspirations could be realized," including making the turbines larger or using higher pressures, resolving issues related to higher flame temperature and increased flame speed, addressing increased NOx emissions, and additional difficulties related to retrofitting existing combustion turbines.[181]

Section 111 requires more than a "crystal ball inquiry,"[182] and EPA has not met the necessary legal standard to find hydrogen co-firing at these levels adequately demonstrated. Courts have required that a technology must be shown to be reasonably reliable.[183] There must be an operational history that shows more than mere technical feasibility and manufacturer "aspirations"; the

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[179] 88 Fed. Reg. at 33,312 (emphasis added).

[180] Kiewit Report at 14. Another expert notes that EPA references mere "marketing materials" related to hydrogen co-firing from major manufacturers such as GE, Siemens, and Mitsubishi. D. Campbell, Hydrogen in Combustion Turbine Electric Generating Units, at 4 (Aug. 3, 2023) ("Campbell Hydrogen Report") (Attachment J to these comments); *see also id.* at 6 ("Although there is a lot of marketing or forecast development of machines that will run at 30% blends, they are neither demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA requirements.").

[181] Kiewit Report at 14-15 (citing Department of Energy National Energy Technology Laboratory's (DOE/NETL) white paper, "A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control). Kiewit further notes that only relatively small, aeroderivative combustion turbines are currently able to burn higher percentage of hydrogen, but these types of turbines are used as peaking units and therefore would not be subject to the proposed standards. *Id.* at 15.

[182] *Portland Cement Ass'n*, 486 F.2d at 391.

[183] *Essex Chem. Corp.*, 486 F.2d at 433; *NRDC v. Thomas*, 805 F.2d at 428 n.30.

technology must be dependable and effective and based on actual operating experience within the source category or at sufficiently similar sources. This operational history is absent here.[184]

In addition, as EPA acknowledges, increased NOx emissions result from hydrogen combustion, at least at hydrogen blends of 70 percent or greater. But as Kiewit explains, "there is not significant testing data available to show that NOx emissions will not be a problem," even when co-firing 30 percent hydrogen, especially for existing units that are retrofit.[185] The technology of dry low NOx ("DLN") combustion is being developed to combat NOx emissions, but as EPA notes it "is currently more limited."[186] EPA says that developers "are designing combustion turbines … with DLN designs that assure acceptable levels of NOx emissions."[187] These "designs" are not yet final and are unproven.[188] EPA then notes that selective catalytic reduction ("SCR") can be used to further reduce NOx emissions.[189] But EPA does not do any analysis of the cost associated with SCR installation (which is very expensive). EPA needs to analyze the important environmental effect of increased NOx emissions, as well as its increased cost, more thoroughly.

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[184] One expert reviewed available data for hydrogen co-firing demonstrations and concluded "these very limited and short-duration hydrogen co-firing demonstrations do not provide justification to qualify as being adequately demonstrated today and much work would be required to meet a 2032 goal on a commercial basis." Campbell Hydrogen Report at 5.

[185] Kiewit Report at 18.

[186] 88 Fed. Reg. at 33,312.

[187] *Id.*

[188] "[W]hile the [original equipment manufacturers ("OEMs")] are working to produce dry low NOx (DLN) hydrogen combustors that can maintain lower NOx emissions in the future, it is uncertain whether they will be successful at maintaining the levels that are currently achievable. As with the 30% hydrogen firing case, the OEMs' ability to keep NOx low is most limited for the combustion turbines that are retrofitted to fire hydrogen." Kiewit Report at 18.

[189] 88 Fed. Reg. at 33,312.

2. The Supply of Low-GHG Hydrogen Needed to Implement the Proposed Rules Does Not Exist.

The current supply of low-GHG hydrogen is practically non-existent.[190] As EPA acknowledges, "[o]nly small-scale facilities are currently producing [low-GHG] hydrogen through electrolysis with renewable or nuclear energy."[191] Larger facilities are "under development" and "anticipated to significantly increase the availability of low-GHG hydrogen by 2032."[192]

EPA believes that the IRA and the Infrastructure Investment and Jobs Act will result in an ample supply of low-GHG hydrogen. EPA notes that 374 new projects were announced by August 2022 "that would produce 2.2 metatons (Mt) of low-GHG hydrogen annually," which is a 21 percent increase from current levels.[193] First, there is no guarantee that these projects will proceed or be successful. Second, if the current levels, by EPA's own admission are very small, a 21 percent increase from those levels will not amount to much. There is no analysis by EPA of how much low-GHG hydrogen will be needed by 2032 and 2038 and how much of that need will be met by these projects. EPA needs to assess how much low-GHG hydrogen will be needed for this program. Pointing to projects in the absence of those data is meaningless.[194]

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[190] *See* Congressional Research Service, *Hydrogen in Electricity's Future* at 11 (June 30, 2020), https://crsreports.congress.gov/product/pdf/R/R46436 (noting high cost of producing hydrogen).

[191] 88 Fed. Reg. at 33,312.

[192] *Id.*

[193] *Id.*

[194] *See also* Kiewit Report § 3.1 at 19 (explaining that the "timeline [for hydrogen hubs supported by DOE funding] is vastly out of step with the timeline for the GHG rule that the EPA has established"). The Kiewit Report also discusses the daunting task and constraints (e.g., strain on the supply chain for precious metals) faced by the electrolyzer (which is needed for electrolysis—the process needed for producing low-GHG hydrogen) OEMs to increase production enough to meet the demand for hydrogen under the proposed BSER. *Id.* § 4 at 22-24. EPA has not analyzed these issues either.

EPA also fails to address the practical difficulties associated with producing low-GHG hydrogen. Looking at three natural gas-fired plants in Michigan owned by Consumers Energy illustrates the scope of the problem. At the Zeeland Generating Station (an NGCC located in Zeeland, Michigan), a 684 MW solar array would be needed to produce enough low-GHG hydrogen for co-firing at a 30 percent level at that plant. A solar array this large would occupy approximately 7.5 square miles. If that same plant were to co-fire hydrogen at a 96 percent blend, this would require about 4,787 MW of solar generation to produce enough low-GHG hydrogen for the plant. A solar array this large would occupy about 52.4 square miles. The figures are similar for the Jackson Generating Station (an NGCC located in Jackson, Michigan). These figures would approximately double for the Covert Generating Station (a gas-fired EGU in Covert, Michigan). In total, Consumers Energy would need about 19,000 MW of solar energy, covering about 200 square miles to produce the low-GHG hydrogen needed to power these three gas-fired EGUs. These figures are almost 2.5 times the entire solar build that Consumers Energy contemplates over the next twenty years. Importantly, this is only *three* of the gas-fired EGUs that are affected by the Proposed Rules. These figures are exponentially higher when one looks at the fleet of affected gas-fired EGUs as a whole.

Until these concerns about the integrity of the fuel supply and whether there can even be a consistent source of hydrogen are resolved, the Proposed Rules are premature and are not achievable (as required by section 111). The vast majority of hydrogen today is made from natural gas and is very carbon-intense,[195] which EPA correctly notes will not achieve GHG emission reductions. Implementing a hydrogen-based standard makes no sense until there is a strong and

[195] DOE, Office of Energy Efficiency & Renewable Energy, *Hydrogen Production: Natural Gas Reforming*, https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming ("Today, 95% of the hydrogen produced in the United States is made by natural gas reforming in large central plants").

reliable supply of low-GHG hydrogen, which simply does not exist at this time. Because of the lack of supply of low-GHG hydrogen, EPA's proposed BSER is not achievable, and thus not in accordance with section 111.

3. Even if There Were an Ample Supply of Low-GHG Hydrogen to Implement the Proposed Rules, The Infrastructure Needed to Transport and Store the Hydrogen Does Not Exist.

Even assuming that there could be an ample supply of low-GHG hydrogen by 2032 and 2038 to fulfill the requirements of the Proposed Rules, the infrastructure to support transporting and storing the hydrogen is completely lacking at this time.

Some of the issues associated with CCS are also present with hydrogen combustion. For example, as with CCS, there needs to be a means to physically store the hydrogen.[196] Hydrogen can be stored in salt caverns, depleted oil and gas reservoirs, aquifers, abandoned mines, or rock caverns, but these features need to be close to the EGU—which is not always possible. While hydrogen can be stored in pressure vessels, this requires proper materials to avoid embrittlement. It would also require vast acreage,[197] and has safety and fire protection implications. In addition, like CCS, water is a significant issue. Producing enough hydrogen for a natural-gas plant requires enormous amounts of water, which is not available in large parts of the country.[198]

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[196] *See, e.g.*, DOE, NETL, *Underground Hydrogen Storage Remains a Key Research Topic for NETL* (Aug. 22, 2022), https://netl.doe.gov/node/11982.

[197] *See* Kiewit Report § 2.3 at 16-17 ("5 days of storage … for the H-Class turbine … would be approximately 17 acres of storage tanks.").

[198] D. Pimentel, et al., *Renewable Energy: Current and Potential Issues: Renewable energy technologies could, if developed and implemented, provide nearly 50% of US energy needs; this would require about 17% of US land resources* at 1115, BioScience, Vol. 52, No. 12 (Dec. 2002), https://academic.oup.com/bioscience/article/52/12/1111/223002 (noting "[t]he water required for electrolytic production of 1 billion kWh per year of hydrogen is approximately 300 million liters of water per year," amounting to 3000 liters of water per year on a per capita basis, and noting that "[w]ater for the production of hydrogen may be a problem in arid regions of the United States and the world"); *see also* Campbell Hydrogen Report at 4 ("EPA also notes … that 'for each kg of hydrogen produced through electrolysis, 9 kg of by-product oxygen are also produced and 9 kg of purified water are consumed.' To create enough fuel to run a single LM 6000 at 46.6 MW gross on

A standard of performance under section 111 must be achievable "for the industry as a whole."[199] EPA has not done any analysis of the important issues associated with storing hydrogen, nor has it analyzed the important issue of the amount of water needed to produce hydrogen. This is again a failure to address a critical part of the problem and is arbitrary and capricious as a result.[200]

The pipeline network for hydrogen in the United States is in its infancy and consists of 1,600 miles of pipelines.[201] In contrast, the pipeline network for natural gas covers over 300,000 miles.[202] For EGUs not immediately near a low-GHG hydrogen generating facility, the construction of a pipeline to transport the low-GHG hydrogen is necessary in order for the performance standard to be achievable. But, as discussed above, the cost to construct a pipeline is very high and permitting is a years-long process. While more established pipelines (such as for natural gas) are met with increasing resistance, this may be elevated for hydrogen, which is even more explosive.[203] This may

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100% hydrogen, one would use 173,142 US gallons of water per day just to make hydrogen. Any additional water requirements to run the unit would be added to this. In many regions of North America, water resources are at a premium now and would not be able to support these levels of low-GHG hydrogen production, so this provides another challenge to the hydrogen supply.").

[199] *National Lime*, 627 F.2d at 431.

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

[201] 88 Fed. Reg. at 33,313.

[202] Congressional Research Service: Pipeline Transportation of Hydrogen: Regulation, Research, and Policy at 5 (Mar. 2, 2021), https://crsreports.congress.gov/product/pdf/R/R46700. Using the existing natural gas pipeline infrastructure to deliver hydrogen to combustion turbines would not achieve the proposed BSER requirements. *See* Campbell Hydrogen Report at 6 ("Although there is much talk about blending hydrogen into the natural gas transmission and distribution system, an amount of between 1% and 5% is likely all that is practical without major changes to end use equipment. This does not meet a 30% blend target in 2032.").

[203] *See* Kiewit Report at 21 ("Much of [the new hydrogen] pipeline will need to be routed in highly populated areas. Given the safety concerns discussed in Section 3.2, the issue of supply pipelines is a significant barrier to the practicality of the hydrogen requirements of the proposed rule.").

make permitting even more difficult. The Agency also completely ignores safety issues for hydrogen pipelines and fails to do any analysis of this critical issue.[204]

EPA's response to this achievability problem is to note that "[t]he majority of announced combustion turbine EGU projects proposing co-firing hydrogen are located close to the source of hydrogen. Therefore, fuel delivery systems (i.e., pipes) … can be designed to transport hydrogen without additional costs."[205] All but one of the announced projects that EPA cites, several of which are Kiewit projects, are not yet in operation. Kiewit notes that the facility that is in operation "can only fire hydrogen for 45 minutes before it runs out of storage."[206] Moreover, "none of these units are expected to fire anywhere close to 96% hydrogen initially. Instead, they expect to burn between 30-50% hydrogen, with an aspirational goal of having the capability of firing more."[207] Kiewit continues: "the timeline for most of these projects to be firing 100% hydrogen is 2045. This is significant since these units are the *early adopters*, with high aspirations for firing hydrogen. The 2045 date of these units, which the EPA presents as examples of what is possible with hydrogen firing, cannot support EPA's 2038 deadline for 96% hydrogen firing."[208]

Even if EPA's claims that most EGU projects proposing to co-fire hydrogen will be located near hydrogen sources were true and relevant, while the construction near the source of the low-GHG hydrogen might be conceivable for new EGUs, it "give[s] a competitive advantage to one State over another in attracting industry," in violation of section 111.[209] And this solution is

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[204] *See id.* at 20 (discussing safety issues for hydrogen pipelines and noting "EPA's discussion of pipelines does not address the significant challenges of this transport piping at all").

[205] 88 Fed. Reg. at 33,314.

[206] Kiewit Report at 11.

[207] *Id.*

[208] *Id.*

[209] *Sierra Club*, 657 F.2d at 325.

completely unworkable for existing EGUs, unless the owner or operator wants to prematurely retire an EGU and construct a new one near a low-GHG hydrogen source. As with geologic storage issues with regard to CCS, this leads to a state that does not have a low-GHG facility being harmed twice (once when a plant in its borders closes and again when the new construction takes place in another state).

EPA also seems to suggest that trucking hydrogen is a cost-effective option up to 200 miles.[210] Even a small combustion turbine would require so many trucks to keep it running that the "logistics of moving this many trucks would be unmanageable."[211] Even "[w]ith the trucks being unloaded 12 hours per day, it would take between 12 and 24 days to unload the number of trucks for a single F-Class turbine to provide 1 day of hydrogen storage. It would take between 17 and 35 days of truck deliveries for a single H-Class turbine and 1 day of storage."[212]

EPA has failed to consider myriad issues relating to the transportation and storage of hydrogen. As such, its proposal for hydrogen co-firing to be the BSER for certain subcategories of combustion turbines is arbitrary, capricious, and otherwise not in accordance with the CAA.

4. EPA's Proposed BSER for Hydrogen Co-Firing Impermissibly Redefines the Source.

EPA notes in the Proposed Rules that the Supreme Court in *West Virginia v. EPA* noted "with approval … that 'fuel-switching' was one of the 'more traditional air pollution control measures.'"[213] The traditional types of fuel-switching that were being referenced there were not a change from one fuel type to an entirely different one. Rather, it reflects measures such as switching

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210 EPA, Office of Air and Radiation, Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document at 28 (May 23, 2023); *see also* 88 Fed. Reg. at 33,309.

211 Campbell Hydrogen Report at 5.

212 Kiewit Report at 17.

213 88 Fed. Reg. at 33,315 (quoting *West Virginia v. EPA*,142 S. Ct. 2587, 2615 (2022)).

from high-sulfur coal to lower-sulfur coal. That is not the case here. Here, EPA proposes to replace natural gas (one type of fuel) with hydrogen (a completely different type of fuel).

EPA also apparently failed to read footnote three in the Supreme Court's opinion. There, the Court noted that the dissenting opinion suggested that EPA could require coal-fired plants to become natural gas-fired plants to reach the same environmental result. But the Court said that "EPA has never ordered anything remotely like that, and we doubt it could."[214] Yet, this is exactly what EPA is attempting to do here. By 2032, a natural gas-fired combustion turbine must become a hybrid plant that burns large quantities of both natural gas and hydrogen. And by 2038, a natural gas-fired combustion turbine is required to "co-fire" 96 percent hydrogen. Any combustion turbine that combusts 96 percent hydrogen is a hydrogen-fired combustion turbine; it is no longer a gas-fired turbine.

EPA cannot force a natural gas-fired turbine to no longer burn natural gas. This is considered "redefining the source," which is not permissible under the CAA.[215] EPA must withdraw hydrogen co-firing as a BSER option for new and existing combustion turbines.

D. Co-Firing with Natural Gas at Coal-Fired EGUs Does Not Meet the Requirements of Section 111 and Impermissibly Redefines the Source.

EPA is proposing that the BSER for medium-term existing coal-fired steam generating units (i.e., those units that will operate after January 1, 2035, but retire before January 1, 2040) is natural

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[214] *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3

[215] *See, e.g.*, *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3 (expressing "doubt" EPA could "requir[e] coal plants to become natural gas plants"); *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2448 (2014) (finding that Best Available Control Technology, which is intertwined with section 111, "cannot be used to order a fundamental redesign of the facility"); *In re Prairie State Generating Co.*, 13 E.A.B. at 25 (holding that it is "long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design"); *Sierra Club v. EPA*, 499 F.3d 653, 655-56 (7th Cir. 2007) (recognizing the choice of fuels is an essential part of a source's purpose and design, and requiring a source to change its design to combust an alternative fuel constitutes redefining the source).

gas co-firing at 40 percent.[216] EPA says it "believes that because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating in place of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system…."[217] EPA's statement misses the point. While there may be an ample supply of natural gas in the United States, natural gas co-firing is not sufficiently available across the fleet. In 2017, only about one-third of coal-fired EGUs co-fired with *any* amount of natural gas.[218] That number has not changed substantially since that time. Of these units, only four percent actually co-fire significant amounts of natural gas for the purpose of generating electricity.[219] The vast majority of EGUs that have co-firing capability use the natural gas at very low levels for the purposes of starting up the boiler or holding it in "warm standby." And "using natural gas for ignition is not the same as co-firing with natural gas."[220] As one expert notes, "[i]n fact, it is common practice to shut down the natural gas igniters once the flame is established, so co-firing during normal operation is not as common a practice as the report would suggest. Several factors contribute to that practice including the supply of natural gas, quantity available, and operational aspects of the boiler."[221]

For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost prohibitive because the cost of gaining access is approximately $4 to $10 million per mile of pipeline required. For example, at the New Madrid Power Plant (operated by PGen member Associated Electric Cooperative, Inc. ("AECI")) in Marston, Missouri, the closest pipeline with capacity and

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[216] 88 Fed. Reg. at 33,338.

[217] *Id.*

[218] 84 Fed. Reg. at 32,544.

[219] *Id.*

[220] W. Morris & J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on The Generation Alternative of Fuel Switching to Natural Gas at 3 (Aug. 3, 2023) ("Morris Gas Co-Firing Report") (Attachment K to these comments).

[221] *Id.*

pressure to support the plant is 46 miles away with an estimated capital cost in 2008 dollars of $213,798,000 to connect the pipeline to the plant (i.e., at a cost of $4,647,783 per mile). This cost estimate does *not* include additional costs for gas contracts and annual operating costs. Similarly, at AECI's Thomas Hill Energy Center in Clifton Hill, Missouri, the closest gas line is 14 miles away with an estimated capital cost in 2008 dollars of $59,500,000 to connect (i.e., at a cost of $4,250,000 per mile). Securing the right of way, surveying, and permitting (none of which is guaranteed) can be expected to take three years with construction taking another two years, and those timelines can be achieved only if there is not any litigation or challenges to the permits.[222]

For those facilities that can co-fire, an additional challenge may be acquiring sufficient natural gas to co-fire at higher rates on a consistent basis.[223] The requirement to co-fire natural gas in significant quantities would require the fuel to be available at all times (called "firm" access), which is even more expensive and less available than the non-firm form of access that is currently far more common at existing coal-fired EGUs.[224] Existing pipeline infrastructure to the plant may be unable to accommodate greater gas delivery, or pipeline gas pressure may be too low to deliver additional gas to the property line.[225] Further, gas is often unavailable at certain times of the year, which could

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[222] *Id.* at 7.

[223] *See id.* at 4-9 (discussing problems and challenges arising from "Availability of Natural Gas During Periods of Inclement Weather and High Demand," the "Inadequacy of Natural Gas Transmission and Distribution Infrastructure for Fuel Switching," the "Difficulty and Cost Associated with Procuring Natural Gas Service at a Coal Plant," "Plant Design Challenges," and "Cost"). EPA has failed to analyze these problems and challenges.

[224] Comments of Great River Energy at 3 (Nov. 2, 2018), available in the docket for the Affordable Clean Energy Rule at EPA-HQ-OAR-2017-0355-23734; *see also* Morris Gas Co-Firing Report at 4 (noting, for example, that "[t]he supply of natural gas is already insufficient in the PJM region without the forced fuel switching and blending requirements that the EPA is proposing").

[225] *See* Morris Gas Co-Firing Report at 7 ("[T]he presence of a natural gas pipeline near a plant is not an indication of adequate capacity. For example, [one of the authors] … is experienced with the Coal Creek Station north of Bismarck, ND. [The map] shows a gas line just east of the plant, however, that line does not even have enough capacity to provide ignition fuel for the 1,100 MW coal plant."); *id.* (describing as mere "speculation" EPA's statement that "'[e]ven if a generator doesn't necessarily

result in a reliability problem.[226] Whether co-firing is viable ultimately requires a site-by-site analysis. Because EPA's proposed BSER is not achievable "for the industry as a whole" and not just a subset of sources, it is unlawful.[227]

In addition, as discussed above in Section IV.C with regard to hydrogen co-firing, the Supreme Court has said with regard to a coal-fired plant becoming a natural gas-fired plant (which is exactly what EPA is proposing to do here) that "EPA has never ordered anything remotely like that, and we doubt it could."[228] By 2030, any coal-fired steam generating unit that plans on operating after January 1, 2035, and retiring before January 1, 2040, must meet an emission limitation based on the co-firing of 40 percent natural gas. This turns a coal-fired plant into a hybrid coal/gas plant, which redefines the source; something that is not permissible under the CAA.[229] EPA must withdraw its BSER determination for medium-term coal-fired steam generating units.

E. EPA's Assumption that Technologies and Their Required Infrastructure Will Be Adequately Demonstrated and Achievable Several Years—and in Some Cases More Than a Decade—in the Future Is Not Reasonable and Violates the CAA.

In the Proposed Rules, EPA notes that in making an "adequately demonstrated" determination, it "'may make a projection based on existing technology,'" and it is not necessary "that the system 'must be in actual routine use somewhere.'"[230] While this is the case, EPA is constrained in that any projections that it makes are "subject to the restraints of reasonableness and

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report burning natural gas, in many cases, coal-fired EGUs are located in the vicinity of other generating assets. In the cases where coal-fired EGUs are located near natural gas EGUs, they likely have access to an existing supply of natural gas.'").

[226] Comments of Duke Energy Business Services at 12-13 (Nov. 9, 2018), available in the docket for the Affordable Clean Energy Rule at EPA-HQ-OAR-2017-0355-24821.

[227] *National Lime Ass'n*, 627 F.2d at 431.

[228] *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3.

[229] *See supra* note 215.

[230] 88 Fed. Reg. at 33,272 (quoting *Portland Cement*, 486 F.2d at 391)).

cannot be based on 'crystal ball' inquiry."[231] EPA's projections cannot be "wispy hopes based on no evidence at all."[232]

EPA's projections in the Proposed Rules are not reasonable and are rather "wispy hopes." While there may be instances where a technology is adequately demonstrated but some lead time may be needed "to design, acquire, install, and begin to operate" the technology (which might be allowed under the CAA),[233] it is not permissible under the CAA to prognosticate years (and even more than a decade) into the future and decide that a technology that is neither currently adequately demonstrated nor achievable will magically meet those legal thresholds at that time. Indeed, EPA's approach here is to assume that all of the problems that it has identified with regard to several of its BSER selections (CCS at both steam generating units and combustion turbines, hydrogen co-firing at combustion turbines, and natural gas co-firing at steam generating units) will be solved by the passage of time. This approach violates the requirements of section 111 that a system of emission reduction be adequately demonstrated and achievable at the time a rule is proposed and is arbitrary, capricious, and unlawful.

Once CCS, hydrogen co-firing, or other potential technologies meet the statutory requirements that a system of emission reduction be adequately demonstrated and achievable, EPA can then propose performance standards based on those technologies. Indeed, under section 111(b), EPA can always revise an NSPS at any time; it does not need to wait 8 years to do so.[234] Moreover, for existing sources, section 111(d) does not give EPA a deadline by which it must propose emission

[231] *Portland Cement*, 486 F.2d at 391.

[232] *NRDC v. Thomas*, 805 F.2d at 432.

[233] 88 Fed. Reg. at 33,273.

[234] CAA § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B) (specifying that EPA "shall, *at least* every 8 years, review and, if appropriate, revise such standards") (emphasis added).

guidelines for those sources.[235] EPA must wait until CCS and hydrogen co-firing meet the statutory requirements of section 111 before proposing standards of performance or emission guidelines based on these technologies. The Proposed Rules findings regarding adequate demonstration and achievability for these technologies are premature and should be withdrawn.

V. EPA's Timeline for Compliance with the Proposed Rules is Unrealistic.

The Proposed Rules contain timelines that are unrealistic and unachievable. The most egregious of these are the timelines for medium- and long-term existing coal-fired steam generating units (i.e., those coal-fired EGUs whose owners and operators intend to operate them past January 1, 2035, or January 1, 2040, respectively). Under the Proposed Rules, these medium- and long-term units must begin compliance with their relevant emission limitation beginning on January 1, 2030.[236] This deadline all but necessitates that existing coal-fired units will likely need to be subcategorized as either imminent- or near-term EGUs (and thus forced to retire no later than December 31, 2034) because the owners and operators of these units will not be able to install the technology and infrastructure needed to meet the emission limits for medium- or long-term units by 2030.

Coal-fired EGUs that are subcategorized as long-term must meet, by January 1, 2030, a presumptively approvable standard of performance that is based on a BSER of CCS with 90 percent capture of CO_2 and that reflects an 88.4 percent reduction in the unit's annual emission rate (in lb CO_2/MWh) from the unit's baseline.[237] Even assuming that this technology met the definition of adequately demonstrated and could be installed on a commercial scale (which it does not and cannot as described in detail in Section IV.B), it is infeasible to have CCS installed and operational on a unit in this timeframe. There are simply too many hurdles, including permitting, to be overcome. Unless

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[235] *See id.* § 111(d), 42 U.S.C. § 7411(d).

[236] Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(A).

[237] 88 Fed. Reg. at 33,359, Table 5.

the owner or operator of a coal-fired EGU has already begun the process of pursuing CCS for the unit, *it is already too late*. First, it can take years simply to evaluate storage sites and conduct geologic testing.[238] This first step was undertaken for a CO_2 storage pilot project in northeastern Arizona and took three years and $5.7 million in investment—only to find out that the site had insufficient permeability to proceed with CO_2 injection.[239] Applications for Class VI wells, which are required for geologic storage of CO_2, are currently backed up at EPA.[240] Nationwide, only five Class VI permits have been issued, with a backlog of 33 permit applications pending.[241] States that have submitted an application to EPA for primacy in Class VI permitting are experiencing a similar backlog.[242] For example, Arizona submitted a primacy application to EPA in September 2022 that has not been acted upon. The Arizona Department of Environmental Quality believes EPA may act on this application by late 2023.

Another complicating—and time-consuming—factor occurs if the EGU is not located right above a geologic storage site. In those cases, pipelines need to be constructed to transport the CO_2 and depending on how close an EGU is to a storage facility, these pipelines may need to run hundreds of miles. The permitting and construction of pipelines takes years, faces fierce opposition,

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[238] *See, e.g.*, EERC Report at 11 (EPA's "timeline shown in Figure 2 depicts 2.5 years for storage feasibility, site characterization, and permitting. This is an extremely optimistic and aggressive timeline. For example, the U.S. Department of Energy's CarbonSAFE Program assumes a 5-year timeline to address feasibility, characterization, and permitting. Even for states with Class VI primacy such as North Dakota, storage feasibility, site characterization, and permitting could take up to 4.5 years.").

[239] *See supra* p. 40 & notes 146, 147.

[240] *See* EERC Report at 11 ("For states without primacy, storage feasibility, site characterization, and permitting could take up to 6.5 years based on historical EPA permitting timelines from the two approved EPA UIC Class VI permits.").

[241] Hunton Andrews Kurth, Class VI Program Permit Tracker, https://www.huntonak.com/en/class-vi-program-permit-tracker.html.

[242] *Id.*

and is extremely expensive.[243] Recent experience of one PGen member constructing pipelines resulted in a cost of $5 to $10 million per mile. The permitting and construction of pipelines also takes many years.[244] This is compounded, for projects that must be completed in the next few years (i.e., by 2030) by supply chain issues.[245]

Similar problems also arise with the presumptively approvable standard of performance for medium-term coal-fired EGUs. The standard of performance for those units is based on co-firing 40 percent natural gas. Most coal-fired EGUs do not have access to natural gas, which means that a pipeline would need to be constructed. As just discussed with regard to CCS, building a pipeline is an endeavor that may not be approved and will take years to permit and construct even if it is ultimately approvable. Even for those coal-fired EGUs that do have access to natural gas, they may not be able to obtain the quantities of natural gas needed to co-fire at this level on a reliable basis (or even at all depending on the pipeline and infrastructure).[246]

Daniel Walsh, Senior Director for Generation Research and Development at PGen member the National Rural Electric Cooperative Association, conducted an in-depth analysis of the timeline likely needed for a CCS project. He concludes, "[b]ased on the information and research obtained,

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[243] The Mountain Valley Pipeline that is proposed for construction in North Carolina and Virginia is an example. Work on that pipeline began in May 2018—more than five years ago. MVP Southgate, Overview, https://www.mvpsouthgate.com/overview/. The pipeline is still not completed and has been the subject of controversy and litigation, including before the Supreme Court. J. Kruzel, Reuters, *US Supreme Court removes obstacle to Mountain Valley Pipeline* (July 27, 2023), https://www.reuters.com/legal/us-supreme-court-removes-obstacle-mountain-valley-pipeline-2023-07-27/.

[244] EERC Report at 11-12 ("Depending on the route of the pipeline, permits for water body crossings, federal lands, and the Army Corps of Engineers can take a year or more to acquire, if the permit is allowed at all. In addition, agreements with landowners for rights of way … for the pipeline can take a year or longer, depending on the length of the pipeline. In all, the listed time of 2.5 years for pipeline feasibility, design, and permitting appears to be overly optimistic.").

[245] *Id.* at 12.

[246] Morris Gas Co-Firing Report at 7.

an accurate time for the construction of a project is more **in the range of 10-12 years after inception**."[247] Because the timeline for owners and operators of coal-fired EGUs to have all of this infrastructure and permitting completed by January 1, 2030—and have all of the technology working properly by that date—is infeasible, it will almost certainly lead owners and operators to have to subcategorize their units differently: as either imminent-term (meaning the unit will have to retire no later than January 1, 2032) or as near-term (meaning the unit will have to retire no later than January 1, 2035, *and* agree to restrict the unit's capacity factor to 20 percent) regardless of whether the unit has more remaining useful life and regardless of whether the unit is needed to meet electric reliability needs.

VI. The Proposed Rules Violate the Major Questions Doctrine, which the Supreme Court Warned EPA About in West Virginia v. EPA.

EPA's two prior rules regulating GHG emissions from existing EGUs under section 111(d) of the CAA—the Clean Power Plan and the Affordable Clean Energy Rule—were examined by the U.S. Supreme Court last year in *West Virginia v. EPA*.[248] The Court held "there are 'extraordinary cases' that call for a different approach" than deferring to an administrative agency such as EPA.[249] These are "cases in 'which the history and breadth of the authority that the agency asserted' and the 'economic and political significance' of that assertion, provided a 'reason to hesitate before concluding that Congress meant to confer such authority."[250] Although the Court had applied this rationale in previous cases, it gave a name to this principle—the Major Questions Doctrine—for the first time in *West Virginia*.

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[247] Walsh Report at 4 (emphasis in original).

[248] 142 S. Ct. at 2587. The rule under review by the Supreme Court in *West Virginia* was the Affordable Clean Energy Rule and that rule's repeal of the Clean Power Plan.

[249] *Id.* at 2608 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)).

[250] *Id.*

In the Clean Power Plan, EPA relied on an approach based on "generation shifting" where non-GHG emitting forms of generation such as wind and solar would be favored over lower-GHG emitting natural gas-fired generation, followed last by coal-fired generation (which has higher GHG emissions than gas-fired generation). The Supreme Court found in *West Virginia* that the Clean Power Plan's approach violated the major questions doctrine for four reasons. First, the Clean Power Plan differed significantly in approach from all previous rules by EPA under section 111(d), which had relied on a BSER that was based on emissions reducing "measures that would reduce pollution by causing the regulated source to operate more cleanly…. [EPA] had never devised a cap by looking to a 'system' that would reduce pollution simply by 'shifting' polluting activity from dirtier to cleaner sources."[251] The Court found that this "unprecedented" view of EPA's authority "effected a 'fundamental revision of the statute, changing it from [one sort of] scheme of regulation' into an entirely different kind."[252] This new interpretation would allow EPA to:

> demand much greater reductions in emissions based on a very different kind of policy judgment that it would be "best" if coal made up a much smaller share of national electricity generation. And on this view of EPA's authority, it could go further, perhaps forcing coal plants to 'shift' away virtually all of their generation—*i.e.*, to cease making power altogether.[253]

Second, the Court found that EPA dictating the optimal mix of energy sources is not within the Agency's traditional area of expertise, and the Court said "[t]here is little reason to think Congress assigned such decisions to the Agency," especially given that "EPA itself admitted … '[u]nderstand[ing] and project[ing] system-wide … trends in areas such as electricity transmission, distribution, and storage' requires 'technical and policy expertise *not* traditionally needed in EPA

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[251] *Id.* at 2610 (internal quotation and citation omitted).

[252] *Id.* at 2612 (quoting *MCI Telecomms. Corp. v. AT&T*, 512 U.S. 218, 231 (1994)).

[253] *Id.*

regulatory development.'"[254] The Court found "little reason to think Congress assigned such decisions" that are outside EPA's expertise to the Agency, and "'[w]hen [an] agency has no comparative expertise' in making certain policy judgments, [the Court has] said, 'Congress presumably would not' task it with doing so."[255]

Third, the Court went on to "find it 'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," especially "in the previously little-used backwater of Section 111(d)."[256] The types of "basic and consequential tradeoffs"—decisions that would be required in making such a decision—"are ones that Congress would likely have intended for itself."[257]

Finally, the Court found it noteworthy that Congress had "'considered and rejected' multiple times" proposals to amend the CAA to create a cap-and-trade program such as that promulgated in the Clean Power Plan or "to enact similar measures, such as a carbon tax."[258] For all of these reasons, the Court found that the major questions doctrine applied and held that section 111(d) does not contain the "'clear congressional authorization'" that is required to regulate in the manner that EPA tried to do under the Clean Power Plan.[259]

As detailed below, EPA's Proposed Rules do not fix the legal infirmities identified by the Supreme Court in *West Virginia*, and as a result the Proposed Rules violate the major questions doctrine and are unlawful. While the Clean Power Plan was more forthright about its generation

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[254] *Id.* at 2612 (quoting EPA, Fiscal Year 2016 Justification of Appropriation Estimates for the Committee on Appropriations 213 (2015)) (emphasis in original).

[255] *Id.* at 2612-13 (quoting *Kisor v. Wilkie*, 139 S. Ct. 2400, 2417 (2019)).

[256] *Id.* at 2613 (quoting *MCI*, 512 U.S. at 231)).

[257] *Id.*

[258] *Id.* at 2614 (quoting *Brown & Williamson*, 529 U.S. at 144).

[259] *Id.* (quoting *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 324 (2014)).

shifting approach and its aim to reduce fossil fuel-fired electric generation and "dictate the optimal mix of energy sources nationwide,"[260] the Proposed Rules lead to the exact same results: a shifting away from fossil fuel-fired generation and a dictation of what EPA views as the optimal mix of energy sources in the United States.

First, although EPA now bases the Proposed Rules on emissions reducing technologies and "measures that would reduce pollution by causing the regulated source to operate more cleanly," the fact of the matter is that these technologies—although promising—are not yet adequately demonstrated, are not achievable, and are not cost-effective as discussed in detail in Section IV, even with the IRA *possibly* providing financial assistance in some circumstances.[261] And even if these technologies were adequately demonstrated, achievable, and cost-effective (which they are not), the timetable (particularly for coal-fired EGUs)[262] for implementing these technologies and measures is so unreasonable that it likely cannot be met. The end result is that owners and operators will have little choice but to either retire units prematurely or severely curtail their use (and then retire prematurely) in order to comply with the Proposed Rules.

Second, the Proposed Rules continue to dictate what EPA views as the optimal mix of energy sources within the United States. The rules essentially result in: little to no coal-fired

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[260] *Id.* at 2613.

[261] The possibility that a project may receive funding under the IRA is just that: a possibility. EPA cannot count on these funds to be available for every project in its cost-benefit analysis. *See, e.g.*, Morris CCS Report at 8-10.

[262] Indeed, the fact that EPA requires coal-fired EGUs to begin compliance with very stringent emissions requirements beginning in 2030, while gas-fired EGUs remain in a "business as usual" stance until later, shows that EPA is again prioritizing gas-fired generation over coal-fired generation—just as it did in the Clean Power Plan. *Compare* Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(A) (requiring coal-fired steam generating units to begin final compliance with the standard of performance by January 1, 2030), *with* Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(B), (C) (requiring gas-fired combustion turbines to begin final compliance with the standard of performance by either January 1, 2032, or January 1, 2035).

generation, with gas-fired generation used only for peaking purposes and to back up renewable generation. The Supreme Court clearly said EPA does not have authority in this regard, and the Proposed Rules violate the major questions doctrine.

For example, if an owner or operator wants a coal-fired unit to operate in 2040 and beyond, it must meet—beginning in 2030—an emission limit based on CCS.[263] As discussed in Section IV.B, while CCS is a promising technology, it is neither adequately demonstrated nor available. Moreover, the timeframe is unrealistic, as discussed in Section V. In effect, this requirement forces those owners or operators to subcategorize their coal-fired steam generating units as imminent-term (committing to a retirement before 2032)[264] or near-term (committing to a retirement before 2035 and a restriction that the unit cannot operate above a 20 percent capacity factor).[265] For those coal-fired EGUs that have ready-access to a firm supply of natural gas, those units might be able to operate until 2040 by co-firing natural gas[266] (which gives rise to other legal issues regarding fuel switching and redefinition of the source).

The situation is similar for new gas-fired EGUs. EPA's rules have the effect of allowing construction of only "peaking" units to back up renewable generation. All other construction requires a unit to eventually be able to co-fire low-GHG hydrogen (for which there is no reliable supply and for which there is no infrastructure to transport it even if there were a reliable supply) or to install CCS (something that has never been done at an electric utility CT to date). Existing gas-fired combustion turbines fare no better, with baseload units (the ones most needed to ensure

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[263] *See, e.g.*, *id.* § 60.5740b(a)(4)(viii)(A).

[264] *Id.* § 60.5740b(a)(1)(D).

[265] *Id.* § 60.5740b(a)(1)(C).

[266] *Id.* §§ 60.5740b(a)(1)(B), 60.5775b(c)(2).

electric reliability) restricted to operating at half their capacity or being required to co-fire low-GHG hydrogen beginning in 2032 or to install CCS by 2035.

Third, it continues to be "'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," and the provision of the CAA on which EPA relies as the authority for the Proposed Rules continues to be "the previously little-used backwater of Section 111(d)."[267] No previous EPA rulemaking under section 111(d) has ever required technology that is not yet ready and available—nor has EPA ever required under section 111(d) the installation of these not yet available technologies years—and in some cases more than a decade—out in the future.

Fourth and finally, Congress continues to wrestle with the issue of climate change and how to address it, with several recent bills showing widely disparate views on the issue.[268] Congress has consistently rejected programs like the one proposed here that would severely limit fossil fuel-fired electric generation in the United States.[269] While Congress did recently enact the IRA, that statute is focused on promoting the development of the nascent and promising technologies of CCS and

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[267] *West Virginia v. EPA*, 142 S. Ct. at 2613.

[268] *See, e.g.*, Preparing Superfund for Climate Change Act of 2023, H.R. 1444, 118th Cong. (2023) (bill that would require consideration of climate change when selecting remedial actions for the cleanup of Superfund sites); To provide for the withdrawal of the United States from the United Nations Framework Convention on Climate Change, and for other purposes, H.R. 2781, 118th Cong. (2023); Coastal State Climate Preparedness Act of 2023, H.R. 2735, 118th Cong. (2023) (bill that would direct the Commerce Department to establish a coastal climate change adaptation preparedness and response program that would be voluntary for states); Green New Deal for Health Act, H.R. 2764, 118th Cong. (2023) (bill that would create programs to mitigate the health effects of climate change); Real Emergencies Act, S.2118, 118th Cong. (2023) (bill that would prohibit the president from declaring a national emergency on the basis of climate change).

[269] *See, e.g.*, American Clean Energy and Security Act, H.R. 2454, 111th Cong. (2009) (climate cap-and-trade bill that did not pass the Senate); Clean Energy Jobs & American Power Act, S.1733, 111th Cong. (2009) (rejected cap-and-trade legislation).

hydrogen co-firing that are mandated by the Proposed Rules and not on the direct limitation or curtailment of fossil fuel-fired electric generation.[270]

EPA also exceeds its authority under the CAA by setting NSPS and presumptively approvable emission limits for existing sources that do not go into effect for many years (in some instances more than a decade in the future) and bases these emission limitations on technologies it anticipates being demonstrated far in the future. The CAA speaks to technology that "has been" adequately demonstrated—not "will be" adequately demonstrated. Further, EPA's attempt to transform coal-fired EGUs into gas-fired EGUs and to transform gas-fired EGUs into hydrogen-fired EGUs in the future confronts an issue of major economic and political significance. If Congress had wanted to give this authority to EPA, it was required to do so clearly and unambiguously. This is not the case, and Congress cannot give EPA such vast authority through purported ambiguities in its phrasing.

For all of these reasons, the Proposed Rules violate the major questions doctrine. EPA should withdraw the Proposed Rules and re-propose rules that do not run afoul of the doctrine and that meet the standards of section 111 of the Clean Air Act in terms of being based on a system of emission reduction that is adequately demonstrated, achievable, and cost-effective. EPA can always revise a performance standard under section 111(b) of the CAA at any time, and it could do so if and when the technologies of CCS, hydrogen combustion, or other feasible technologies meet this important legal standard. Moreover, EPA does not have a deadline under section 111(d) to establish

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[270] *See, e.g.*, The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action at 9 (Jan. 2023), https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf (The IRA "is the most ambitious investment in clean energy in our nation's history. It includes more than 20 new or modified tax incentives and tens of billions of dollars in grant and loan programs to unleash new clean energy technology investment and deployment and supercharge our transition to a clean energy economy.").

emission guidelines for existing EGUs, and it should wait for these or other technologies to be developed further before requiring them.

VII. The Applicability Dates for the Proposed Rules are Incorrect as a Matter of Law.

EPA correctly notes in the Proposed Rules that "the CAA defines an 'existing source' as 'any stationary source other than a new source,'" and further correctly notes that the proposed emission guidelines for existing sources "would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT."[271] This is the correct analysis and conclusion under the CAA. Yet, on June 12, 2023, EPA issued a "Memo to the Docket" entitled "Applicability of Emission Guidelines to the Existing Stationary Combustion Turbines: FAQs" ("Applicability Memo").[272] In this document, EPA inexplicably changes course and "clarifies" that "[s]tationary combustion turbines that commenced construction or reconstruction before May 23, 2023, are existing sources that may be affected EGUs under the proposed UUUUb [the proposed emission guideline]."[273] EPA now says that the term "EGUs" in the preamble refers only to steam generating units (i.e., utility boilers). This is not what the proposed regulatory text says. Section 60.5700b of the proposed regulatory text says explicitly that a "natural gas fired stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU." EPA's position in the Applicability Memo conflicts with this explicit proposed language.

EPA correctly cites section 111(a)(6) of the CAA, which defines an "existing source" as "any stationary source other than a new source."[274] This statutory text is unambiguous. A source cannot

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[271] 88 Fed. Reg. at 33,342.

[272] Docket ID No. EPA-HQ-OAR-2023-0072-0143.

[273] Applicability Memo at 2.

[274] CAA § 111(a)(6), 42 U.S.C. § 7411(a)(6).

be both "new" and "existing." Stationary combustion turbines constructed after January 8, 2014, are "new" sources that complied with Subpart TTTT. These units cannot be "existing"—and thus subject to a section 111(d) emission guideline—under the plain text of the CAA. A "new source" is "*any* stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing *a* standard of performance under this section which will be applicable to such source."[275] Combustion turbines constructed after January 8, 2014, whose CO_2 emissions were subject to Subpart TTTT are "new sources" under section 111—and therefore cannot be existing sources—because those sources are already subject to "*a* standard of performance" for CO_2 under section 111.

In addition, it is arbitrary and capricious for EPA to say (correctly) that steam generating units that complied with Subpart TTTT are "new" sources (and thus not subject to the proposed emission guidelines) while stationary combustion turbines that complied with that same provision are "existing" sources that are subject to the proposed emission guidelines. EPA must make clear that any EGU—whether a steam generating unit or a stationary combustion turbine—that commenced construction prior to January 14, 2014 (or that commenced a reconstruction or modification after June 18, 2014) and was subject to Subpart TTTT is *not* an existing source for the purposes of the proposed emission guideline. The proposed emission guideline should apply only to EGUs that commenced construction prior to those dates (and that did not undergo a modification or reconstruction after June 18, 2014). Any other interpretation is contrary to the plain language of the CAA and is unlawful.

[275] *Id.* § 111(a)(1), 42 U.S.C. § 7411(a)(1) (emphasis added).

VIII. The Proposed Rules Impermissibly Restrict States' RULOF Determinations.

As PGen noted in its comments on EPA's proposed revisions to the section 111(d) implementation regulations of Subpart Ba,[276] Congress directed that EPA's implementing regulations under section 111(d) "*shall* permit the State in applying a standard of performance to any particular source under a plan submitted [under section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[277] While EPA has the authority to approve or disapprove of a state plan, it cannot unduly limit a state's discretion to take RULOF into account.

EPA should not unduly restrict states' ability to examine RULOF. In the interest of finding a least-cost pathway to reducing CO_2 emissions, RULOF is an important aspect of the section 111(d) analysis. Despite this, in the Proposed Rules, EPA is putting too many restrictions on a state's remaining useful life analysis to such an extent that states will be unable to take advantage of the ability that Congress gave them to have less stringent standards in certain circumstances. For example, EPA's proposal that sources that have a less stringent emission limitation based on a state's remaining useful life analysis cannot participate in an emissions trading program is arbitrary and capricious and not grounded in the statute. As discussed in more detail in Section IX.B, there is no compelling reason why a source subject to RULOF cannot be included in a trading program. The emissions cap for that source simply needs to be calculated (and added to the overall cap) based on its less stringent RULOF-based emission limitation.

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[276] Comments of the Power Generators Air Coalition on EPA's Proposed Rule Entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Action Section 111(d)," Docket ID No. EPA-HQ-OAR-2021-0527-0097 (Feb. 27, 2023). These comments are incorporated herein by reference and attached as Attachment L.

[277] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (emphasis added).

In the Proposed Rules, EPA also implies that a state needs to invoke the RULOF provisions *only* when a state is proposing a less stringent emission standard for a designated facility, and RULOF does not apply if a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA.[278] Using this same logic, EPA should similarly make clear that if a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that state plan should be approved by EPA as "satisfactory."[279] This is particularly important for any state that may use flexible compliance mechanisms such as a cap-and-trade program where the overall stringency of the program is achieved through the emissions cap, but a particular unit may exceed the equivalent of its emission limitation and comply by obtaining and surrendering allowances or a program like emissions averaging where a particular unit may exceed the equivalent of its emission limitation but comply by averaging its emissions with a unit that has over-complied with its emission limitation. This principle was implied in the preamble to the proposed revisions to the Subpart Ba section 111(d) implementation regulations where EPA stated that:

> [T]he proposed RULOF provisions … would apply where a state intends to *depart* from the presumptive standards in the [emissions guideline] and propose a less stringent standard … and not where a state intends to *comply* by demonstrating that a facility or group of

[278] 88 Fed. Reg. at 33,383 (noting "a State may not invoke RULOF to provide a less stringent standard of performance for a particular source if that source cannot apply the BSER but can reasonably implement a different system of emission reduction to achieve the degree of emission limitation required by the EPA's BSER determination").

[279] It should be noted that EPA's review of a state plan under section 111(d) (i.e., to determine whether the plan is "satisfactory") is less rigorous than its review of state implementation plans under section 110 of the CAA (which requires that all statutory criteria be met). *Compare* CAA § 111(d)(2)(A) (noting EPA has authority to prescribe a federal plan "where the State fails to submit a satisfactory plan") *with* CAA § 110(k)(3) (noting EPA must approve a state implementation plan "if it meets all of the applicable requirements of this chapter"). And even with regard to EPA's review of state implementation plans under section 110, the Agency's role is "limited," *Texas v. EPA*, 690 F.3d 670, 675 (5th Cir. 2012), and "confine[d] … to the ministerial function of reviewing [state implementation plans] for consistency with the Act's requirements," *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012).

> facilities subject to a state program would, in the aggregate, achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the [emissions guideline] at individual designated facilities.[280]

EPA should make this point explicitly in the emission guidelines.

In addition, PGen disagrees with EPA's statement in the Proposed Rules that because EPA "considered impacts on the energy sector as part of its BSER determinations," that energy impacts "would not be [an] appropriate basis for invoking RULOF."[281] This conflicts with the plain language of the CAA, which expressly says that "nonair quality health and environmental impact and energy requirements" must be taken into account in setting a standard of performance.[282] Because states set the standard of performance for existing sources under section 111(d), the statute specifically *requires* them to take energy requirements into account, and anything in the Proposed Rules that restricts their ability to do that is unlawful and contrary to the plain language of the CAA.[283]

As PGen stated in its Pre-Proposal Comments, existing fossil fuel-fired EGUs that rarely operate should be allowed to comply with alternative emission limitation requirements, and "[t]hese units could be subject to limitations on the amount they may operate in a given year."[284] There may be important energy requirements (i.e., reliability reasons) why a state may want to keep open a plant that is used rarely. Companies will not be willing to invest necessary sums in such a unit and thus under the Proposed Rules will be forced to retire the unit. Rather than having the unit retire, states may decide it is better policy to place an operating restriction on the unit that limits its use—yet

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[280] 87 Fed. Reg. 79,176, 79,198 (Dec. 23, 2022) (emphasis in original).

[281] 88 Fed. Reg. at 33,382 n.628.

[282] CAA § 111(a)(1); 42 U.S.C. § 7411(a)(1).

[283] In addition, EPA is not the expert on energy resource adequacy and reliability, and its attempt to evaluate the impact of the Proposed Rules on the power sector is woefully inadequate. *See infra* Section XI (discussing EPA's use of the IPM model).

[284] PGen Pre-Proposal Comments at 7.

leaves it available when needed. Allowing states to invoke RULOF to allow for a less stringent standard for these facilities to preserve reliability is permissible under the statute because the state is properly taking energy requirements into account. In these instances, where a state plan that contains a less stringent emission limitation and a restriction on the unit's operating capacity based on RULOF for a designated facility, PGen agrees that any such capacity restriction must be included in the state plan as an enforceable requirement.

Further, states should be allowed to modify a subcategory in their state plans to address RULOF issues. For example, if a coal-fired steam generating unit is planning to retire at the end of 2032, and the state determines that the unit is needed for reliability purposes at greater than a 20% capacity factor, the state should be allowed to subcategorize that unit as an "imminent-term" unit even though it will operate a little longer than that subcategory's December 31, 2031 retirement deadline. Under this hypothetical, the state can justify this modification of the subcategory under two separate RULOF grounds: (1) remaining useful life—it would make no sense to require the owner and operator of the unit to invest substantial sums at the unit given it would be retiring soon; and (2) energy requirements—the state can demonstrate that the unit is needed at a higher capacity than the 20% restriction placed on near-term units. EPA should make clear in the final emissions guidelines that states have the authority to modify the subcategories when justified by RULOF considerations.

IX. EPA Should Assist the States by Providing a Model Trading Rule Based on Mass-Based Presumptively Approvable Emission Limits that States Can Adopt.

For all the reasons discussed herein, PGen believes that the Proposed Rules are unlawful and should be withdrawn by EPA. If EPA decides nevertheless to proceed to finalize the rules (or proposes new rules), PGen strongly supports EPA's proposal "to allow states to incorporate averaging and emission trading into their State plans, provided that states ensure that use of these compliance flexibilities will result in a level of emission performance by the affected EGUs that is equivalent to each source individually achieving its standard of performance."[285] In its Pre-Proposal Comments, PGen set out a recommended approach that it asked EPA to adopt in its emission guideline addressing GHG emissions from existing fossil fuel-fired EGUs.[286] The recommended approach had three main components that PGen requested: (1) EPA should make clear that states have the authority to offer a wide array of flexible options (such as emissions averaging and emissions trading) to assist sources in meeting their performance standards;[287] (2) EPA should follow the approach that it has taken in prior rulemakings and develop a model trading rule that incorporates these types of flexible options that would provide states with an easy way to participate in a cap-and-trade program if they choose to do so;[288] and (3) EPA should convert any rate-based emission limitations to a mass-based emission rate.[289] EPA partially adopted this approach in the Proposed Rules by making clear that states do have the ability to rely on flexible options for compliance. Unfortunately, however, EPA did not issue a model trading rule for states to adopt or convert the presumptively approvable rate-based emission limits into mass-based limits. PGen urges EPA to do these things and reiterates that doing so is a good policy decision.

A. EPA Should Issue a Model Trading Rule for Existing Sources that States May Opt Into and that Would Be a Fully Approvable and Automatic State Plan.

As EPA has recognized, "[a]nnual progress reports demonstrate that EPA trading programs have been successful in mitigating the problems they were designed to address, exhibiting significant

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[285] 88 Fed. Reg. at 33,392.

[286] PGen Pre-Proposal Comments at 5.

[287] *Id.* at 5, 8.

[288] *Id.* at 5, 9.

[289] *Id.* at 5, 15-16.

emission reductions and extraordinarily high levels of compliance."[290] Compliance flexibility also provides incentives for sources to pursue additional emission reductions beyond those required by a rule. When EPA promulgated the Clean Air Mercury Rule in 2005,[291] it established a model trading program as an implementation tool to assist sources in meeting their performance standards, and states had a choice regarding whether to participate in the trading program.[292] Participation in the trading program was "a fully approvable control strategy for achieving all of the emissions reductions required under the final rule in a more cost-effective manner than other control strategies."[293] States were also permitted to deviate from the model rule in certain respects "to best suit their unique circumstances."[294] EPA also followed this approach in the Clean Power Plan where the Agency proposed a model trading rule that would also serve as a federal plan in the event a state failed to submit a satisfactory state plan.[295] EPA should follow this approach again.

The vast majority of states do not have the experience with emissions trading programs that EPA has, nor do most states have the resources that are needed to create these types of programs. As EPA acknowledges, there are numerous procedures and systems that states would need to

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[290] 88 Fed. Reg. at 33,393 (citing EPA, Power Sector Programs Progress Report (2021), https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_full_report.pdf).

[291] 70 Fed. Reg. 28,606 (May 18, 2005). The U.S. Court of Appeals for the D.C. Circuit vacated the Clean Air Mercury Rule for reasons having nothing to do with the model trading program. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[292] 70 Fed. Reg. at 28,624-32.

[293] *Id.* at 28,625.

[294] *Id.*

[295] 80 Fed. Reg. 64,966 (Oct. 23, 2015). Although the Clean Power Plan was stayed by the Supreme Court and the basis for its BSER ultimately rejected by that court in *West Virginia v. EPA*, nothing in the Court's rationale rejects the approach PGen urges here of the Agency issuing a model trading rule.

establish to put an emissions trading program into place.[296] The preparation of a model trading rule that states could adopt would bypass the need for states to figure all of this out for themselves. And as EPA notes, it has extensive experience with allowance trading programs and already has the infrastructure for reporting and compliance tracking in place.[297]

States that choose to adopt any model trading rule that EPA issues would also benefit from the certainty of having automatically approvable state plans. This approach would also benefit states that have only a handful of affected EGUs (or as in the case of North Dakota, only one affected EGU). For these states, compliance flexibility is non-existent unless there can be emission trading or averaging with other states. If a state desires to cooperate with other states, the approach of having a model trading rule would relieve them of the time, legwork, and uncertainty involved in coordinating and negotiating with dozens of other jurisdictions. This approach has yet another advantage in that it provides EPA with a federal plan that it can easily use if a state either fails to submit a state plan or in the event a state plan is not deemed to be satisfactory by EPA.

PGen also encourages EPA to consider offering incentives as part of its model rule to reward early action and to ensure credits remain for some period of time when units shut down, as has been done in other trading programs like the Cross-State Air Pollution Rule, the Clean Air Interstate Rule, and the NOx SIP Call. EPA should want to encourage states to adopt these types of flexible implementation programs as a policy matter. As EPA noted when it proposed the Clean Air Mercury Rule, the Agency's "significant experience" with cap-and-trade programs for utilities has

[296] 88 Fed. Reg. at 33,395 (noting states need to establish: compliance timeframes, the mechanics to demonstrate compliance, monitoring and reporting requirements, a tracking system for tradable compliance instruments, and a method for distribution of allowances in a mass-based system).

[297] *Id.*

shown that such programs cause emissions to fall *below* the mandated cap, despite increased electric generation, while "maximizing overall cost-effectiveness."[298]

Ensuring that states have maximum flexibility by being able to adopt a model trading rule will ease a lot of the issues that exist at this time with the Proposed Rules and with the regulation of GHG emissions from existing fossil fuel-fired EGUs generally. For example, a cap-and-trade program will help preserve reliability during the energy transition and will help keep electricity affordable because it will allow fossil fuel-fired EGUs that are rarely used to continue to be operated for the purpose of stabilizing the grid during times of peak load (such as during times of extreme heat or cold or because of an extreme weather event) because the owners and operators of those EGUs can forgo significant capital investment in those units and instead buy allowances to cover those units' limited emissions. In addition, a cap-and-trade program will help by providing time for technologies that are showing promise to mature and for funding from the IRA to be deployed, which will help spur advancements in technology development.

B. EPA Should Not Unduly Restrict Emissions Trading.

In the Proposed Rules, EPA asks for feedback on how a cap-and-trade program could be structured for existing affected sources.[299] PGen encourages EPA to issue a model rule that is broadly applicable across all affected fossil fuel-fired EGUs, regardless of their subcategory and regardless of whether they are steam generating units or stationary combustion turbines. To do this, EPA could examine each affected EGU and determine what its historical operating profile is (i.e., how much it operates annually on average) by looking back at its operations over a given time

[298] 69 Fed. Reg. 4652, 4697 (Jan. 30, 2004); *see also id.* (noting that trading "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces" and that "[s]ources have an incentive to endeavor to reduce their emissions below the number of allowances they receive").

[299] *See generally* 88 Fed. Reg. at 33,393-96.

period. PGen suggests that a three- to five-year lookback period would be beneficial (such as perhaps a lookback period of 2018-2022) and suggests that any lookback period should extend back before 2020 to ensure the numbers are not skewed in an unrepresentative fashion by the COVID-19 pandemic. Once EPA determines a unit's annual historical average operations, it can then determine what the unit's annual budget should be under the model trading program by calculating its CO_2 emissions over that period of time using the presumptively approvable emission limitation for that type of unit.

EPA suggests that it might be inappropriate to include EGUs for which the BSER is "routine methods of operation" (e.g., imminent-term and near-term coal-fired steam generating units) in a trading program.[300] While calculating the emissions budget for those units might be slightly more complicated because it would be very unit-specific (as opposed to relying on a presumptively approvable emission limitation), it would not be impossible to do. In addition to determining a unit's historical average operations over a given period of time, EPA (or the state) would also determine the unit's historical emissions over that period of time. For example, for a near-term coal-fired EGU, EPA would examine its historical emissions over the relevant period of time and then restrict those emissions based on a 20 percent capacity factor (a requirement for the near-term subcategory) to determine the emissions budget for the unit. The allowances for that EGU would disappear from the program beginning in 2035, which is the date by which a near-term unit needs to commit to retire.

Similarly, EPA's belief that "it would not be appropriate to allow affected EGUs with less-stringent source-specific standards based on RULOF to comply with those standards of performance through trading," is misplaced.[301] There is no valid reason why an EGU subject to a

[300] *Id.* at 33,393.

[301] *See id.* at 33,393-94.

source-specific standard based on a RULOF determination could not be included in a trading program. Again, the emissions budget for that EGU would be determined based on its historical average operations and its less-stringent, RULOF-based emission rate as determined by the state.

All of these calculations would lead to an emissions cap for the state (or a collection of states if part of an EPA model trading rule or an interstate trading program). As long as the emissions cap is not exceeded, the end result is the same in terms of environmental benefits and reduced GHG emissions as it would be if there were not any trading involved. In fact, the end result might be even better because as EPA acknowledges:

> In general, emission trading programs provide flexibility for EGUs to *secure emission reductions at a lower cost relative to more prescriptive forms of regulation*. Emission trading can allow the owners and operators of EGUs to *prioritize emission reduction actions where they are the quickest or cheapest to achieve while still meeting electricity demand and broader environmental and economic and performance goals*. These benefits are heightened where there is a diverse set of emission sources (e.g., variation in technology, fuel type, age, and operating parameters) included in an emission trading program. This diversity of sources is typically accompanied by differences in marginal emission abatement costs and operating parameters, resulting in heterogeneity in economic emission reduction opportunities that can be optimized through the compliance flexibility provided through emission trading. In addition, the EPA has observed, with the support of multiple independent analyses, that *there is significant evidence that implementation of trading programs prompted general innovation and deployment of clean technologies that reduce emissions and control costs*.[302]

It would also not be difficult to control for the different subcategories. As shown above, the emissions budget for a near-term coal-fired steam generating unit would be its historical emissions rate calculated with a capacity factor limitation of 20 percent, with the allowances for that unit being removed from the program beginning in 2035 (the year by which a near-term unit commits to retire). Similarly, a medium-term steam generating unit would have an emissions budget that would

[302] *Id.* at 33,393 (emphases added).

be calculated by determining its historical emission rate less a 16 percent reduction (the presumptively approvable standard of performance for this type of EGU), with the allowances for that unit being removed from the program beginning in 2040 (the year by which a medium-term unit commits to retire under the Proposed Rules).

PGen urges EPA not to include dynamic budgeting and to allow banking of allowances in any model trading program under the Proposed Rules because it will stifle the incentives under the market to retire units early or to reduce utilization at units. Those incentives exist only if banking is allowed and if budgets do not change. Moreover, there is no need for dynamic budgeting because the program becomes increasingly more stringent as time passes with key years where the overall emissions budget will reduce occurring in 2032, 2035, 2038, and 2040.

C. EPA Should Provide States with Alternative Mass-Based Presumptively Approvable Emission Limits.

Any model trading rule developed by EPA should be mass-based. As EPA notes, "[o]wners and operators of EGUs, utilities, and State agencies … have extensive familiarity with mass-based emission trading, which could make the design and implementation of a mass-based trading program as part of a State plan relatively straightforward."[303] When EPA proposed the Clean Power Plan in 2014, it provided states with a technical support document to assist states with translating emission rate-based goals to a mass-based equivalent.[304] In response to states' requests for further assistance, EPA converted the rate-based goals of each state into a mass-based goal.[305] EPA noted

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[303] *Id.* at 33,395.

[304] EPA, Office of Air and Radiation, Technical Support Document, Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents (Nov. 2014), https://archive.epa.gov/epa/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf.

[305] EPA, Clean Power Plan Toolbox, Clean Power Plan State-Specific Fact Sheets, https://archive.epa.gov/epa/cleanpowerplantoolbox/clean-power-plan-state-specific-fact-sheets.html.

that the goals were "designed to be met as part of the grid and over time, reflecting the inherent flexibility in the way the power system operates and the variety of ways in which the electricity system can deliver a broad range of opportunities for compliance for power plants and states."[306] EPA should follow a similar approach here and convert its presumptively approvable emission rates for affected sources into presumptively approvable mass-based emission rates (e.g., tons of CO_2 per year) regardless of whether it ultimately issues a model trading rule.

Expressing the emission limit as a mass-based rate has numerous advantages. First, it makes it easier for states to incorporate flexible compliance mechanisms such as emissions averaging or cap-and-trade programs into their state plans. Several states already have carbon trading programs with mass-based caps,[307] and the ability of those states to incorporate those programs into a trading program designed under section 111(d) would be beneficial. Additionally, EGUs have a lot of experience and familiarity with cap-and-trade programs (such as the Acid Rain Program and the Cross-State Air Pollution Rule) that are mass-based. Staying with an approach that is proven and with which EGUs have significant experience makes sense.

Second, it eases reliability concerns because older, less efficient fossil fuel-fired EGUs that are rarely used can be available for use when needed (i.e., in times of extreme heat or cold) when the grid is strained. For example, if a unit's emission limit is expressed as tons per year, these types of units can run for short periods of time as needed to ease the strain on the grid without fear of violating a short-term rate-based limit.

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[306] *Id.*

[307] *See, e.g.*, Regional Greenhouse Gas Initiative, https://www.rggi.org/ (CO_2 cap-and-trade in the eastern portion of the United States covering EGUs in 14 states); California Cap-and-Trade Program, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program (CO_2 cap-and-trade program in California that covers EGUs and other industries).

Third, because the GHG emission rate at units tends to increase over time as the unit ages, expressing the emission limitation as tons per year allows the unit to continue to operate. The unit may need to operate less over the course of a year but would not have to cease operation (which could happen under a rate-based approach).

PGen urges EPA to assist states and to convert its presumptively approvable emission rates for affected EGUs into presumptively approvable mass-based emission rates (e.g., tons of CO_2 per year).

In conclusion, PGen recommends EPA develop and issue a model trading rule that states can opt into for their state plans. This approach has many benefits: (1) it aids the states in developing approvable state plans; (2) it provides much needed flexibility to owners and operators to comply with the Proposed Rules and continue to provide reliable and affordable electricity; and (3) it would provide significant benefits to environmental justice communities, as discussed further in Section X. In developing this model rule, EPA should not unduly restrict trading so that owners and operators have maximum compliance flexibility, which in turn leads to maximum emission reductions and reduced costs. Finally, regardless of whether EPA issues a model trading rule, EPA should convert its presumptively approvable emission limitations from rate-based standards (lb CO_2/MWh) into mass-based standards (tons CO_2/year).

X. EPA's Environmental Justice Analysis Should Examine the Effects on Environmental Justice Communities of Decreased Electric Reliability and Lack of Access to Affordable Electricity.

As part of its development of the Proposed Rules, EPA examined the impact of the rulemaking in terms of air pollution effects on environmental justice ("EJ") communities.[308] EPA analyzed the impacts of the Proposed Rules on climate change, which it says will disproportionately

[308] 88 Fed. Reg. at 33,413.

affect EJ communities, and analyzed the Proposed Rules' effect on "other health-harming air pollutants from EGUs."[309] EPA generally found that emission reductions will be small and broadly distributed across all demographic groups.[310] In addition to analyzing those impacts, however, EPA must examine the impacts of costly regulations on EJ communities and how the Proposed Rules will affect those communities' access to affordable electricity. In particular, there is a clear and unique potential for harm to EJ communities that could flow from rules that do not adequately protect electric reliability. EPA also needs to acknowledge that flexible compliance measures such as emissions averaging and trading that states may adopt (and that EPA may develop as part of a model trading rule for the Proposed Rules) have been shown to further environmental benefits in environmental justice communities. Finally, the preamble to the Proposed Rules notes concerns that EJ advocacy organizations expressed during the pre-proposal phase of these proceedings. EPA has not, however, adequately responded to those concerns. Each of these items is discussed further below.

A. Electricity Prices and Energy Security

As the EIA explains, "[e]lectricity prices generally reflect the cost to build, finance, maintain, and operate power plants and the electricity grid."[311] Power plants costs, which include financing, construction, maintenance, and operating costs, are one of the key factors affecting electricity prices. Costs associated with emissions controls are included among these power plant costs and can be significant. Increases in electricity prices disproportionately impact EJ communities, which already pay a significant percentage of their income toward energy costs and force economic trade-offs that

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[309] *Id.* at 33,247.

[310] *Id.*

[311] U.S. Energy Information Administration, *Electricity explained: Factors affecting electricity prices*, https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php (emphasis removed).

further imperil energy security in these communities.[312] The increases in electricity prices that will result from the Proposed Rules will only exacerbate this impact and cause additional hardship to lower income (EJ) communities.

Regardless of the specific rules governing electric markets, electric rates are set to recover the cost of delivering electricity. Accordingly, the additional costs associated with the Proposed Rules will be passed through to electric ratepayers. As explained in the RIA for this rulemaking, EPA projects that average retail electricity prices at both the national and regional level will experience the largest impacts in 2030, rising by 2 percent above baseline levels in that year.[313] In 2035, EPA projects that the Proposed Rules will result in a 0.24 percent increase in national average retail electricity price.[314] In 2024, EPA projects a 0.08 percent increase in national average retail electricity price.[315] In reality, these figures are much higher because EPA has overestimated the benefits of the IRA in the baseline (as discussed in Section XI) and underestimated the cost of CCS and co-firing hydrogen (as discussed in Sections IV.B and IV.C, respectively).[316]

A better and more realistic analysis of what the actual impact on electricity prices may be comes from EPA's evaluation of the Clean Power Plan. There, EPA concluded that the emission controls and compliance costs associated with that rule would result in annual costs ranging from

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[312] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

[313] RIA at 3-28.

[314] *Id.*

[315] *Id.* at 3-29.

[316] As discussed in those sections, EPA's reliance on the IRA as the means by which the Proposed Rules become cost-effective is misplaced. There is no guarantee that all (or, indeed, any) of the projects that would be needed to comply with the Proposed Rules would receive funding under the IRA. EPA has also substantially underestimated the cost of the Proposed Rules by adopting a base case that assumes an unrealistic impact of the IRA on coal-fired EGU retirements by 2030. *See infra* Section XI.

$5.5 billion and $7.5 billion in 2020 to between $7.3 billion and $8.8 billion in 2030.[317] EPA concluded that those costs would lead to "a [four] to [seven] percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020."[318]

The costs of new environmental regulation are likely to fall disproportionally on lower-income households and EJ communities. Lower-income families are more vulnerable to energy costs than higher-income families because energy represents a larger portion of their household budgets. Increased energy costs mean that these households will have less income to spend on other necessities, like food, housing, childcare, and health care. As explained by the National Conference of State Legislatures, studies have shown that EJ communities and low-income families pay a significantly higher share of their income in energy costs.[319] Data from DOE's Low-Income Energy Affordability Data ("LEAD") Tool show that, on average, low-income households pay approximately 9 percent of their income in energy costs, which is three times more than non-low-income households.[320] The American Council for an Energy-Efficient Economy estimates that 25 percent of households have a "high energy burden," defined as above 6 percent of household

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[317] 79 Fed. Reg. 34,830, 34,934-35 (June 18, 2014) (proposed Clean Power Plan).

[318] *Id.* at 34,948. Testimony at an April 14, 2015 congressional hearing confirmed that the Clean Power Plan, like any other environmental rule with significant compliance costs, would substantially increase electricity costs for ratepayers. One energy economist estimated that rates in thirty-one states could be fifteen percent higher each year than they would have been in the absence of the rule. House of Representatives, Report No. 114–171 at 10 (June 19, 2015), https://www.congress.gov/114/crpt/hrpt171/CRPT-114hrpt171.pdf. State officials similarly testified that the proposed Clean Power Plan could result in "potential increases of [twenty-two to fifty percent] in Florida, and between ten and thirty percent in Kansas. *Id.* at 11.

[319] National Conference of State Legislatures, Energy Justice and the Energy Transition at 1 (2022), https://www.ncsl.org/energy/energy-justice-and-the-energy-transition.

[320] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

income.[321] Black, Indigenous, and People of Color communities "often experience the highest energy burdens when compared to more affluent or white households."[322] These disproportionate energy burdens have significant and lasting negative consequences for those that are impacted: "high energy burdens are associated with inadequate housing conditions and have been found to affect physical and mental health, nutrition, and local economic development."[323] For all of these reasons, new regulations to address GHG emissions should take the energy burden on disadvantaged communities into account.

B. Reliability

The Proposed Rules acknowledge that compliance flexibility is key to preserving electric reliability.[324] EPA should further acknowledge that compliance flexibility could benefit EJ communities. In particular, if states adopt plans that do not have adequate compliance flexibility, this could result in electric reliability problems, which are most likely to be borne disproportionately by EJ communities. Indeed, this provides yet another reason why EPA should develop a model trading rule for states to be able to adopt easily, as discussed in Section IX. If states do not adopt flexible compliance mechanisms and reliability problems ensue, industrial customers and customers with financial means will likely install emergency backup generation to manage their electric reliability concerns. These emergency backup units are typically uncontrolled, and frequent use of them could result in worse air quality where they are located, including in already disadvantaged communities located near industry. Residents of disadvantaged communities, on the other hand, will

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[321] American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States (Sept. 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

[322] *Id.* at 2.

[323] *Id.* at 5.

[324] 88 Fed. Reg. at 33,415.

not have the means to be able to install emergency backup generation and will suffer the consequences of any electric service disruptions.

These issues raise concerns regarding "energy justice." The concept of energy justice "is based on the principle that all people should have a reliable, safe, and affordable source of energy."[325] A regulatory system that allows wealthy and privileged communities to avoid electric reliability problems and that would leave EJ communities without a similar remedy would violate environmental and energy justice principles. A flexible cap-and-trade compliance mechanism will likely provide the most efficient and best tested regulatory approach for allowing utilities to ensure electric reliability and will protect EJ communities in the process.

The need for compliance flexibility to protect reliability and to minimize costs to ratepayers is especially important for EJ communities because utilities serving those communities and those with facilities located in disadvantaged areas are often among the smallest electric generating companies and organizations. Electric cooperatives, for instance, are generally among the smallest utilities. According to the National Rural Electric Cooperative Association, electric cooperatives "serve 42 million people, including 92% of persistent poverty counties."[326] Community-owned public power utilities also serve a significant proportion of EJ communities and include many smaller generators.[327] Further, an analysis by the American Council for an Energy Efficient Economy found that areas served by investor-owned utilities, including in some of the nation's

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[325] Aladdine Joroff, *Energy Justice: What It Means and How to Integrate It Into State Regulation of Electricity Markets* at 1 (Nov. 2017), https://elpnet.org/sites/default/files/2020-04/energy_justice_-_what_it_means_and_how_to_integrate_it_into_state_regulation_of_electricity_markets.pdf.

[326] National Rural Electric Cooperative Association, Electric Co-op Facts & Figures (Apr. 28, 2022), https://www.electric.coop/electric-cooperative-fact-sheet.

[327] American Public Power Association, 2022 Public Power Statistical Report, https://www.publicpower.org/system/files/documents/2022%20Public%20Power%20Statistical%20Report.pdf.

largest cities, include customers who face significant energy burdens and that utilities needed significant assistance to better serve these communities.[328] All of these constraints, especially for smaller utilities with limited generation assets, result in decreased options for reducing the costs and impacts of any significant new regulatory program on underserved communities. Flexible compliance mechanisms, like allowance trading, can help to alleviate these problems. For these reasons, EPA should develop a model trading rule so that states can more easily adopt these flexibilities into their state plans.

C. Cap-and-Trade Evaluations

Allowing affected EGUs to comply with the Proposed Rules through an emissions allowance trading program is likely the most direct and legally sound approach for providing the necessary compliance flexibility. It is also clear from recent evaluations of cap-and-trade policies that providing for compliance through allowance trading is unlikely to have negative environmental justice impacts and, in fact, should achieve the opposite.

The California Air Resources Board ("CARB") has, for instance, supported its Carbon Cap-and Trade Program with significant analysis of environmental justice issues. Based on the results of several studies, CARB has concluded that "[t]here is no evidence that the Cap-and-Trade Program has exacerbated local air pollution in environmental justice communities."[329] On the contrary, CARB explains that a 2020 study from the University of California, Santa Barbara found that air quality in EJ communities with large cap-and-trade facilities improved more than air quality in wealthier

[328] A. Drehobl and L. Ross, American Council for an Energy-Efficient Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities at 25-29 (Apr. 2016), https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf.

[329] CARB, FAQ Cap-and-Trade Program, https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

neighborhoods since the state began implementing the Cap-and-Trade Program.[330] That result was confirmed by a 2022 study by the California Office of Environmental Health and Hazard Assessment, which found that "the greatest beneficiaries of reduced emissions from facilities subject to the Cap-and-Trade Program have been disadvantaged communities and communities of color in California."[331]

CARB also makes clear that one of the most effective policy options to address EJ issues is to reduce GHG emissions through allowance trading while addressing local air pollution issues affecting EJ communities using existing legal authorities specifically designed to address localized air quality pollution.[332] This is a reasonable approach to these issues, given that the purpose of the Cap-and-Trade Program is reduction of GHGs, which have no significant localized air quality effect and no direct, exposure-based impact on disadvantaged communities.

EPA itself similarly concluded that an emission allowance cap-and-trade program will not adversely affect EJ communities in its Good Neighbor Plan for the 2015 national ambient air quality standards for ozone.[333] The Good Neighbor Plan is based in significant part on an ozone season emission trading program for NOx emissions from EGUs. The final rule also includes one of EPA's first and most extensive assessments of the EJ impacts of a major regulatory program since the adoption of the Biden administration's new policies on promoting EJ and ensuring that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and

[330] *Id.*

[331] *Id.*

[332] *Id.*

[333] 88 Fed. Reg. 36,654 (June 5, 2023).

commercial operations or programs and policies."[334] To evaluate potential EJ concerns, EPA performed two types of analyses: proximity analyses and exposure analyses.[335] The analyses were intended to determine baseline EJ impacts and potential EJ concerns "after implementation of the regulatory options under consideration" and "whether potential EJ concerns will be created or mitigated compared to the baseline."[336]

EPA's analyses resulted in the following findings: (1) "there likely are potential environmental justice concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline"; (2) "disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration due to similar modeled concentration reductions across population demographics;" and (3) "[d]ue to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline." [337] Accordingly, even when the pollutant at issue does have a localized effect, which is not the case for CO_2, EPA has determined based on quantitative analysis that an emission allowance cap-and-trade program will not adversely affect EJ communities.

Based on California's and EPA's experiences, there is a strong basis for concluding that a regulatory program that adopts an emission allowance trading compliance mechanism will have environmental benefits for EJ communities and potentially reduce disproportionate impacts in addition to net impacts. Such a program could achieve that goal while avoiding negative

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334 *See id.* at 36,845.

335 *Id.*

336 *Id.*

337 *Id.* at 36,845-46

consequences for disadvantaged communities that would result from increased electricity prices and loss of electric reliability in communities that already experience disproportionate energy burdens. For these reasons, EPA should make adoption of flexible compliance methods such as cap-and-trade or emissions averaging as easy as possible for states to accomplish and should prepare a model trading rule that states may choose to adopt. This approach will help ease the burden on disadvantaged communities.

D. Safety

The Proposed Rules acknowledge that a number of EJ organizations "raised strongly held concerns about the potential health, environmental, and safety impacts of CCS."[338] EPA's response to these concerns is simply that the Agency "believes that deployment of CCS can take place in a manner that is protective of public health, safety, and the environment, and should include early and meaningful engagement with affected communities and the public."[339] EPA goes on to note that there are several regulatory programs that may apply to CCS operations.[340]

EPA's response to these concerns does not give adequate consideration to the issues EJ advocates have raised, nor does it fulfill EPA's obligation to meaningfully engage with stakeholders as part of the EJ process. EPA should evaluate what issues the existing regulatory structure addresses, how effective the current regulatory regime may be, and which issues remain unregulated and potentially of concern. Noting that regulations exist without examining what those rules achieve and where regulatory gaps remain does not fully address the issues that concern EJ communities. Given the high priority EPA has placed on EJ issues, a more complete discussion of these issues is especially warranted.

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[338] 88 Fed. Reg. at 33,247.

[339] *Id.*

[340] *Id.* at 33,247-48.

XI. EPA's IPM Analysis on Which the Proposed Rules Rely Is Deeply Flawed.

IPM is EPA's principal modeling tool for evaluating the economic and compliance impacts of its rules on the electric power sector. In this rulemaking, EPA evaluated two modeling scenarios: (i) Pre-IRA 2022 Reference Case (January 2023); and (ii) Post-IRA 2022 Reference Case (March 2023). The Pre-IRA 2022 Reference Case was used in modeling the compliance and economic impact of the proposed ELG rule, which was published on March 29, 2023, while the Post-IRA 2022 Reference Case, which is the Updated Baseline, was used in modeling the economic and compliance impacts of the proposed Mercury and Air Toxics Standards Residual Risk and Technology Review and the Proposed Rules. Both IPM reference cases use the EIA's Annual Energy Outlook (AEO) 2021 to forecast future electrical demand.[341]

The aspects of the Proposed Rules that EPA evaluated in its IPM runs are fundamental to a rulemaking under Section 111 of the Clean Air Act—economic impact (i.e., costs), impact of the rule on the energy mix and the reliability of the power grid, etc. Flawed IPM modeling and analysis means that EPA has failed to consider or properly analyze an "important aspect of the problem."[342]

EPA's post-IRA IPM model run is the "base case" from which the impacts of the Proposed Rules are evaluated. EPA's base case, however, contains unrealistic and wildly optimistic assumptions about the impact of the IRA on coal retirements and CCS retrofits, as well as the amount of renewables that would replace the retired generation. As a result, the impact of the Proposed Rules is grossly underestimated.

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[341] Additional information and references for IPM and its use in this rulemaking is provided in J. Marchetti, Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants – Proposed Rule (Aug. 7, 2023) ("Marchetti IPM Report") (Attachment M to these comments).

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

A. EPA's Base Case Is an Outlier, Inconsistent with Every Other Available Model, Including That Published by the EIA.

Comparison of the results of EPA's post-IRA IPM to the EIA's 2023 Annual Energy Outlook ("AEO23"), the National Renewable Energy Laboratory's Regional Energy Deployment System ("ReEDS"), EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy ("REGEN") model, and Resources for the Future's Haiku model shows that IPM's base case is an unrealistic outlier.[343] Most notably, all of these other models forecast coal capacity in their Base/Reference Case to be in excess of 100 GW in 2030, except IPM, which projects 69 GW of coal in 2030. In other words, IPM's flawed assumptions result in well more than 31 GW of coal retirements than any other model, without even accounting for the Proposed Rules.[344] This has the effect of greatly underestimating the impact of the Proposed Rules on coal-fired units.

The level of renewable capacity that IPM projects in its Base/Reference Case is significantly less than what is projected by the other models. Given the level of coal capacity IPM "retires" in its Base/Reference Case, one would expect a greater amount of renewable/storage capacity to be installed, especially in 2028 and 2030. Yet, the data show the exact opposite. The problem, it turns out, is that EPA's IPM model assumes an unrealistically low renewables/storage-to-coal replacement ratio. For example, AEO23 has more than 20 times more renewable/storage capacity replacing one MW of retired coal, while ReEDS has anywhere from 15 to 20 times more renewable/storage capacity replacing one MW of retired coal. The IPM base case assumes a replacement ratio of less than 2 (1.8 and 1.4 for the years 2030 and 2028, respectively).[345]

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[343] Marchetti IPM Report, at 3-10.

[344] *Id.* at 6-7.

[345] *Id.* at 7-9.

The renewables/storage-to-coal replacement ratio is an important consideration because renewable generation is "non-dispatchable"—i.e., it is not always available and thus cannot be dispatched at full, installed capacity whenever needed because renewable generation is dependent on uncontrollable factors such as the amount of sunshine or wind; while coal and gas generation is dispatchable—i.e., it is always available at full, installed capacity.[346] Accordingly, to maintain reliability, it takes multiple MWs of installed capacity of a renewable resource to replace 1 MW of retired dispatchable capacity.

That the IPM model uses a woefully inadequate renewables/storage-to-coal replacement ratio is further evidence of how unrealistic IPM's base case is. It also has a significant impact on reliability of the electric grid: If as much coal as EPA assumes would be retired does in fact retire as projected, and there are not enough other generation resources to replace it, the reliability of the grid would be severely affected. EPA nowhere considers this.

B. IPM's Updated Baseline Does Not Consider Key Challenges Facing the Power Sector's Transition from Dispatchable Fossil Generation to Renewables.

EPA's IPM Updated Baseline modeling, in particular for 2030, fails to consider grid reliability issues confronting the electric power sector. As mentioned above, EPA in its IPM modeling replaces dispatchable power with non-dispatchable renewable generation without any consideration of the different nature of these two types of generating assets.[347] Nor does EPA consider factors relating to capacity in queues, length of time in the queues, and project completion of renewables.

As the Marchetti IPM Report explains:

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[346] *See supra* note 10.

[347] *See also* Marchetti IPM Report at 14-15 (discussing the importance of "accredited capacity" for renewables and EPA's failure to consider it in its IPM modeling).

> The queue for electric generating resources represents the time a project developer initiates an interconnection request and thereby enters the queue, which is followed by a series of interconnection studies. The studies culminate in an interconnection agreement, which is a contract between the RTO or utility. After this interconnection agreement, the project still must be built; however, most proposed projects are withdrawn during the interconnection study process.[348]

Currently, across the United States, the queues are primarily composed of renewable generation. Only a very small percentage of the projects in the queues are actually built, however. For example, PJM has a historic completion rate (queue to steel in the ground) of 5 percent. "A major factor that is impacting these completion rates are the various interconnection costs associated with renewable generation which have exploded over the past years suggesting limited transmission availability."[349] There is no discussion by EPA, whether in the documentation for its IPM runs or elsewhere in the docket, of interconnection queues or project interconnection rates. This is a substantial flaw in EPA's analysis of the Proposed Rules.

EPA simply does not consider in its IPM modeling the serious reliability concerns already facing the power industry. Indeed, even in the recent past, several RTOs have taken action to delay announced coal generation retirements because of these reliability concerns. These concerns are bound to increase, as more coal retirements are projected. Yet, EPA's unrealistic assumptions project a large amount of retirements by 2030. As the Marchetti IPM Report details, "EPA simply assumes the IRA's financial provisions will alleviate all the uncertainties the power industry will face during this transition period. These assumptions dismiss concerns regarding supply chain problems,

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[348] *Id.* at 12.

[349] *Id.* at 14.

siting, labor shortages, and—most importantly—transmission and other infrastructure needed to support renewables."[350]

In truth, EPA cannot seriously consider reliability issues in IPM, except through the assumptions and constraints it builds into the model (which EPA has clearly not done here). Instead of truly evaluating the reliability implications of its assumptions (and its Proposed Rules), EPA's model (IPM) instantaneously "builds" new resources, without considering the many issues listed above that grid generators and operators are facing.[351] Moreover, at most, IPM is a "resource adequacy" model; it does not evaluate reliability in and of itself. And, as EPA concedes, "resource adequacy … is necessary (but not sufficient) for grid reliability."[352] Yet, the only tool EPA claims to have used to assess the impact of the Proposed Rules on reliability is its IPM model runs (with and without the Proposed Rules). That is an arbitrary and capricious failure to address one of the most important aspects of the problem in this rulemaking.

C. EPA's 2030 "Base Case" Unrealistically Includes Significant Deployment of CCS at Coal-Fired EGUs, Inexplicably Retires Units that are Not Slated for Retirement by 2030, and Contains Other Errors.

EPA's IPM "base case" projects CCS would be used by 2030 at 27 coal-fired units (about 9 GW of capacity). Even assuming that CCS were technically feasible at these units, there is simply not

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350 *Id.* at 11; *see also* Weeda Report at 2 ("Shutting down existing fossil fuel resources, driven by compliance requirements of the EPA's proposed rule, would result in a massive need for renewable energy. This generation is geographically distributed and weather dependent, requiring the need for massive investment in transmission infrastructure and affecting the economics associated with investing in alternative technologies in an effort to keep the electric grid functional and reliable. These investments are expected to amount to trillions of dollars per region of the country and involve huge construction, putting unprecedented demand on labor and materials."); *id.* at 5-7 (discussing transmission issues for large amounts of renewables needed to maintain resource adequacy).

351 Marchetti IPM Report at 16.

352 EPA Office of Air and Radiation, Resource Adequacy Analysis Technical Support Document at 3 (April 2023).

enough time for CCS to be deployed in less than 7 years from the proposal (6 years from the final rule).[353]

The 2028 IPM modeling run retired 108 coal units (51.4 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 58 coal units (28.5 GW). The total number of retirements for the two modeling run years is 166 coal units (79.9 GW).[354] This is incorrect, however, for at least 41 coal units (18.1 GW) that have no plans and are unlikely to retire by 2028 and an additional 25 coal units (15.GW) that have no plans and are unlikely to retire by 2030.[355] There are other errors in the modeling runs for projected coal-to-gas conversions, units that would retire by 2035 and operate at less than 20 percent capacity factor starting in 2030, and individual units that are "projected" to follow an illogical pattern (for example, one unit is projected to retire in the proposal run for the year in which it is projected to retrofit with CCS in the base case; another unit is projected to retire in 2028 but is nonetheless modeled as existing in the 2030 base case run; etc.).[356]

In short, EPA's IPM projections are contradicted by the empirical evidence before the Agency, are replete with unreasonable assumptions, and contain substantial errors. The Agency's reliance on these flawed runs is arbitrary and capricious.

XII. EPA Failed to Provide Sufficient Time for Public Comment on the Proposed Rules, in Violation of the CAA and the Administrative Procedure Act.

Courts have said that Congress intended the Administrative Procedure Act's requirement to provide notice and comment (which is mirrored in section 307(d) of the CAA) "(1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to

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353 *See* Section V (discussing timeline for CCS projects).

354 Marchetti IPM Report at 19.

355 *Id.*

356 *Id.* at 19-22.

support their objections to the rule and thereby enhance the quality of judicial review."[357] The comment period for the Proposed Rules does not meet this legal standard because it fails to provide for meaningful public participation—even with the additional 15-day extension that EPA provided.

First, EPA ignored the requests from numerous affected parties for additional time, including three letters from PGen,[358] expressing concern that the comment period failed to provide the time needed for the public to provide meaningful input on the Proposed Rules. These requests have been submitted by parties whose input is critical to the Proposed Rules, including requests from state environmental agencies[359] and the ISO/RTO Council[360] (which is charged with ensuring the reliability of the electric generating system). These letters overwhelmingly requested that EPA provide 60 additional days for comment.

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[357] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 449 (3d Cir. 2011); *accord Idaho Farm Bureau Fed'n v. Babbitt*, 58 F.3d 1392, 1404 (9th Cir. 1995) ("The purpose of the notice and comment requirement is to provide for meaningful public participation in the rule-making process.").

[358] Letter from A. Wood, Counsel to PGen, to M. Regan (May 23, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0041; Letter from A. Wood, Counsel to PGen, to M. Regan (June 30, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0165; Letter from A. Wood, Counsel to PGen, to M. Regan (July 24, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0248.

[359] *See, e.g.*, Letter from E.E. Chancellor, Interim Executive Director, Texas Commission on Environmental Quality, to EPA (June 5, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0095; Comment of the Oklahoma Department of Environmental Quality (June 1, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0076; Letter from D. Czecholinski, Air Quality Division Director, Arizona Department of Environmental Quality, to EPA (May 23, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0064; Letter from M. Kennedy, Director, Division for Air Quality, Kentucky Energy and Environment Cabinet, Department for Environmental Protection, to EPA (May 31, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0071.

[360] Comment of the ISO/RTO Council (June 8, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0092. The ISO/RTO Council consists of: ISO New England Inc.; PJM Interconnection, L.L.C.; California Independent System Operator Corporation; New York Independent System Operator, Inc.; Midcontinent Independent System Operator, Inc.; Southwest Power Pool, Inc.; and the Electric Reliability Council of Texas, Inc. These groups asked for a 60-day extension in order to have "adequate time to evaluate the Proposed Rule and consider providing input to address any concerns with bulk power grid reliability," *id.* at 1, because "[t]he evaluation of potential reliability impacts … cannot be completed under the current comment time frame," *id.* at 2.

Once EPA announced it was extending the comment period by an additional 15-days, many more letters were sent to the Agency (including two from PGen) explaining that the short extension did not solve the problem.[361] Importantly, these are not the only letters that EPA has received. PGen is aware of several other similar requests that are not in the rulemaking docket.

In addition, members of Congress have expressed concern that the comment period was insufficient. In a letter to EPA dated June 6, 2023, the Chair of the House Energy and Commerce Committee Cathy McMorris Rodgers and other members of the Committee expressed "disappoint[ment] that you declined the Committee's request to provide the public a reasonable period to respond to the Proposal. Considering its unprecedented technical and legal complexity, and EPA's past precedent on similar, less complex rulemakings, we ask that you extend the Proposal's comment period to at least 120 days."[362] Similarly, the Ranking Member of the Senate Environment and Public Works Committee Shelley Moore Capito and other members of the Committee wrote EPA a letter on June 8, 2023, "to express serious concerns with the limited opportunities for public engagement in the rulemaking process for the" Proposed Rules. In a call with reporters after EPA provided the 15-day extension of time, she said she is "concerned that the

[361] *See, e.g.*, Letter from R. Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, to M. Regan, Administrator, EPA (June 15, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0123; Letter from M. Durbin, President, Global Energy Institute and Senior Vice President, Policy, U.S. Chamber of Commerce, to M. Regan, Administrator, EPA (July 13, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0169 (second letter); Letter from J.E. Sloan, Executive Director, The Association of Air Pollution Control Agencies, to J. Goffman, Principal Deputy Assistant Administrator, EPA (June 30, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0164 (second letter).

[362] Letter from C.M. Rodgers, Chair, House Committee on Energy and Commerce, et al., to M. Regan, Administrator, EPA at 1 (June 6, 2023), https://d1dth6e84htgma.cloudfront.net/06_06_23_Letter_to_Administrator_Regan_on_Powerplant_Rules_Comment_Extension_09613a1b3c.pdf?updated_at=2023-06-06T13:34:55.988Z.

EPA could only give us another 15 days…. [W]e asked for measurably more."[363] And the Chair of the House Energy and Commerce Committee Cathy McMorris Rodgers and the Chair of that Committee's Subcommittee on Environment, Manufacturing, and Critical Materials Bill Johnson followed up with EPA in a letter written on July 31, 2023, to state that the decision to extend the comment period by only "a mere 15 days, inclusive of two weekends … raises serious concerns about your adherence to your Clean Air Act and Administrative Procedure Act responsibilities."[364]

Most egregiously, on July 7, 2023, EPA posted a 32-page memorandum to the docket entitled "Integrated Proposal Modeling and Updated Baseline Analysis."[365] This document was accompanied by 22 attachments and four new IPM model run outputs, with each model run containing 18 separate Microsoft Excel spreadsheet outputs totaling 129 megabytes of data. These new data were released with a mere 21 business days left in the comment period and materially changed EPA's original analysis of the Proposed Rules.

Importantly, the comment period of 120 days that was the overwhelming request of parties seeking an extension was *less* time than EPA has previously provided for comments on similar rules. Five separate rules encompass the Proposed Rules, and all of them build on previous rulemakings where EPA promulgated the rules in smaller rulemaking packages *and* allowed for more time even though there was less material on which to comment. For example, when EPA proposed the NSPS

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[363] Curtis Tate, West Virginia Public Broadcasting, *Capito: EPA's New Comment Period On Power Plant Rules Not Enough*, https://www.wvpublic.org/capito-epas-new-comment-period-on-power-plant-rules-not-enough/.

[364] Letter from C.M. Rodgers, Chair, House Committee on Energy and Commerce, and B. Johnson, Chair, Subcommittee on Environment, Manufacturing, and Critical Materials, to M. Regan, Administrator, EPA at 1 (July 31, 2023), https://d1dth6e84htgma.cloudfront.net/07_31_23_Letter_to_Regan_re_EPA_Powerplant_NSPS_2nd_Extention_Request_643548c6a1.pdf.

[365] EPA, Office of Air and Radiation, Integrated Proposal Modeling and Updated Baseline Analysis: Memo to the Docket (July 7, 2023), https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

for new fossil fuel-fired EGUs in 2014, the Agency gave the public 120 days to file comments on the proposed rule. When it proposed emission guidelines for existing fossil fuel-fired EGUs later that year, it provided the public with 165 days to file comment. When the Agency proposed the Affordable Clean Energy Rule and the repeal of the Clean Power Plan (two prior emission guidelines for existing fossil fuel-fired EGUs), it provided 192 days for comment. PGen's request for 120 days is eminently reasonable in comparison—especially considering that all of these prior rules are fractions of the current rulemaking package.

Moreover, EPA is not subject to any deadlines that necessitated having a shortened comment period. There is no valid reason for EPA to have provided a truncated comment period here. The Agency is not subject to any court order or consent decree that requires it to act by any date. EPA began the process for reviewing and proposing revisions to the NSPS within the eight-year statutory deadline, and the Clean Air Act does not contain any deadline by which emission guidelines must be promulgated.

The complexity of the Proposed Rules is illustrated by the fact that EPA took over two years to work on them. When President Biden took office on January 20, 2021, he immediately directed EPA to reconsider and reverse the prior administration's rulemakings regarding greenhouse gas emissions from the electric power sector. After taking 841 days to release a signed pre-publication version of the Proposed Rules (and then releasing the proposed regulatory text and several key technical documents later—including new IPM modeling data nearly two months later), it was unreasonable to expect the public to be able to digest this information in 77 days (or less in the case of the IPM modeling data and other technical documents) and provide EPA with meaningful comments.

EPA's failure to provide sufficient time for interested and affected parties to provide meaningful comment violated the Administrative Procedure Act and the CAA.

XIII. Additional Items Needing Clarification or Changes

PGen would like to highlight a few additional areas in the Proposed Rules in which clarification or minor changes are needed. These areas are:

***Definition of "Electric Generating Capacity"*:** Clarification is needed regarding the definition of "electric generating capacity." The proposed emission guidelines set a threshold for natural gas-fired stationary turbines "with an electric generating capacity equal to or less than 300 MW."[366] The term "electric generating capacity" is not defined, and it could mean several things (e.g., nameplate capacity, maximum capacity as ISO condition, maximum capacity at any ambient condition). Even with EPA's recent release of the Applicability Memo, which focused on the apportioning of steam turbine capacities on combined cycle units and attempted to provide assistance on this issue, there is a lot of confusion on this point, and EPA should clarify exactly what "electric generating capacity" means and how it is calculated.

***Calculation of Electric Generating Capacity at Combined Cycle Units*:** EPA's Applicability Memo explains how steam turbine capacities on combined cycle units should be apportioned. PGen requests that EPA consider eliminating the concept of HRSG apportionment in the Proposed Rules because it is a bad policy to penalize combined cycle units that utilize recovered waste heat only to augment the output of the gas-fired turbine. The steam produced by the HRSG does not cause CO_2 emissions. As currently written, EPA's Proposed Rules may encourage owners and operators of EGUs to consider multiple simple cycle units as a solution to staying below the 300 MW threshold, which could have the effect of increasing CO_2 emissions.

***Increments of Progress*:** As currently drafted, the Proposed Rules require the owners and operators of certain existing sources to begin work on increments of progress before a state plan has

[366] Proposed 40 C.F.R. § 60.5850b(a).

been approved by EPA.[367] These increments of progress include things such as the awarding of contracts.[368] Owners and operators should not have to legally bind themselves in contracts when it remains unclear whether the state plan will be approved. EPA should revise the proposed regulatory text so that the timing to complete increments of progress begins to run after a state plan has been approved by EPA.

Carbon Pollution Standards for EGUs Websites: In the Proposed Rules, EPA proposes "that each State plan must require owners and operators of affected EGUs to establish publicly accessible websites, referred to … as a 'Carbon Pollution Standards for EGUs website,' to which all reporting and recordkeeping information for each affected EGU subject to the State plan would be posted."[369] This proposed requirement is burdensome, unnecessary, and inconsistent with the principles of the Paperwork Reduction Act, which states that "[w]ith respect to the collection of information and the control of paperwork, each agency shall ... certify (and provide a record supporting such certification, including public comments received by the agency) that each collection of information ... is not unnecessarily duplicative of information otherwise reasonably accessible to the agency."[370] EPA also has acknowledged in several instances that a central tenet of the Paperwork Reduction Act is to decrease redundancy and eliminate duplicity.[371] EPA's proposed

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[367] *Id.* § 60.5740b(a)(4).

[368] *Id.* § 60.5740(a)(4)(ii).

[369] 88 Fed. Reg. at 33,400.

[370] 44 U.S.C. § 3506(c)(3)(B).

[371] *See, e.g.*, 81 Fed. Reg. 57,439, 57,440 (Aug. 23, 2016) ("Comments expressed concern about the duplication and overlap of existing rules created by the proposed rule.… The Agency has reviewed the comments and agrees that the inclusion of [certain] provisions in the proposed rule created repetition and overlap, so they have been removed."); 77 Fed. Reg. 66,432, 66,433 (Nov. 5, 2012) ("Modifying the survey to simultaneously collect information for multiple purposes will increase response rates, reduce duplicity in information collected by respondents, and add convenience to respondents."); 69 Fed. Reg. 57,910, 57,910 (Sept. 28, 2004) ("This action is undertaken to

website reporting requirement in the Proposed Rules appear to be inconsistent with the Paperwork Reduction Act's goal of avoiding unnecessarily duplicative procedural steps and requirements. As EPA notes, "this information will also be required to be submitted directly to the EPA and the relevant State regulatory authority."[372] This information is publicly available and sufficient. If EPA wants to make this information available on a website, then it should post the information itself.

* * *

PGen appreciates the opportunity to comment on EPA's Proposed Rules. If EPA has any questions on these comments, or if EPA would like to meet with PGen members to discuss these comments further, it should contact PGen's counsel below, who will work with PGen's Board of Directors to arrange a convenient time.

Dated: August 8, 2023

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consolidate information requirements for the same industry into one [Information Collection Request], for simplification and to avoid duplicity.").

[372] 88 Fed. Reg. at 33,400.

Attachment A

Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units

Docket ID No. EPA-HQ-OAR-2022-0723

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") for its consideration in connection with the Agency's opening of a pre-proposal, non-rulemaking docket "to collect public input to guide the Agency's efforts to reduce emissions of greenhouse gases [("GHGs")] from new and existing fossil fuel-fired electric generating units (EGUs)."[1] EPA has stated that "[t]he goal of this non-rulemaking docket is to gather perspectives from a broad group of stakeholders in advance of our proposed rulemaking(s)."[2] PGen supports this initiative by EPA and is pleased to offer these written comments. PGen met with EPA to discuss this important issue on November 17, 2022, and these comments both reiterate and expand upon points made in that meeting, and respond to specific comments made by EPA. PGen remains available to continue to work with EPA in any way the Agency may find helpful.

I. <u>Background</u>

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies – public power, rural electric cooperatives, and investor-owned utilities – with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[3] Our members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired EGUs that will be the subject of EPA's upcoming rulemaking, as well as renewable resources like wind and solar. As such, PGen is uniquely qualified to provide comments to EPA because its members have owned and operated fossil fuel-fired EGUs for decades and are subject to various provisions of the Clean Air Act ("CAA" or "the Act"), including section 111, the provision that will govern EPA's future rulemaking.

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[1] EPA, Pre-Proposal Public Docket: Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants (Sept. 8, 2022), https://www.epa.gov/stationary-sources-air-pollution/pre-proposal-public-docket-greenhouse-gas-regulations-fossil-fuel.

[2] *Id.*

[3] Additional information about PGen and its members can be found at https://pgen.org/.

At the outset, PGen wants to make clear that it takes seriously the need to reduce GHG emissions to address climate change. The electricity generating sector has made significant GHG reductions, and is the industry with by far the greatest amount of reductions from 2005 to 2021.[4] During that period of time, the electric power sector's GHG emissions have fallen nearly 36 percent,[5] and the sector is no longer the biggest contributor to U.S. GHG emissions.[6] The majority of PGen members have established goals to reduce their GHG emissions, and several PGen members have set net-zero goals.

While PGen members take seriously the need to reduce GHG emissions, they take equally seriously their obligation to provide reliable electricity at an affordable price. EPA should be mindful of reliability and affordability when it reviews the new source performance standards ("NSPS") for GHG emissions from new, modified, and reconstructed EGUs under section 111(b) of the CAA and when it promulgates an emission guideline to address GHG emissions from existing EGUs under section 111(d) of the Act. At a minimum, EPA's regulations should not interfere with the electric generating industry's ability to provide reliable, affordable electricity. Such a negative outcome could undermine public support for electric sector efforts to reduce emissions through low- and zero-carbon sources like wind and solar.

II. Summary of Comments

Reliability and Affordability During the Energy Transition (Section IV)

- EPA needs to recognize that the high rate of retirement of fossil fuel-fired EGUs has strained the electric grid and threatened reliability. As retirements continue at a rapid rate, reliability concerns will only increase. In developing its rules to address GHG emissions from fossil fuel-fired EGUs, EPA must keep reliability concerns at the forefront.
    - To ensure an orderly transition away from fossil fuels that preserves reliability, PGen recommends that EPA consider allowing states to exempt from emission limitation requirements in their state plans those existing fossil fuel-fired EGUs that will retire within a reasonable time period.
    - EPA should also consider allowing states to exempt from emission limitation requirements in their state plans any existing fossil fuel-fired EGU that operates only rarely for the purpose of stabilizing the grid during periods of extreme load. These units could be subject to limitations on the amount they may operate in a given year.

[4] Center for Climate and Energy Solutions, U.S. Emissions, https://www.c2es.org/content/u-s-emissions/ (citing EPA and EIA data for 2022).

[5] *Id.* By comparison, the transportation sector's GHG emissions fell by almost 9 percent and the industrial sector reduced its emissions by a little more than 4 percent over the same period of time.

[6] *Id.* (graphic showing Energy-Related Carbon Dioxide Emissions by Sector).

The Importance of Compliance Flexibility (Section V)

- EPA's final emission guideline should recognize the states' authority to provide flexible options for compliance, including emissions averaging and emissions trading.
  - EPA should follow the approach that it did with the Clean Air Mercury Rule ("CAMR") where it bases an emissions cap on specific control technology and then establishes a trading program as an implementation tool. PGen recommends that EPA issue a model trading rule as it did with CAMR that states can opt into.
  - EPA should also consider offering incentives to award early action and to ensure credits remain for some period of time when units shut down.

Environmental Justice (Section VI)

- EPA should recognize that flexible compliance mechanisms like emissions averaging and trading programs have been shown to benefit environmental justice communities through reduced electricity prices and increased reliability. Analyses by California and EPA of cap-and-trade programs have demonstrated that a regulatory program that adopts an emission allowance trading compliance mechanism will have environmental benefits for environmental justice communities and potentially reduce net and disproportionate impacts. A cap-and-trade program is a particularly good approach to reduce GHGs, which have no significant localized air quality effect and no direct, exposure-based impact on disadvantaged communities.

Timing of State Plan Submissions (Section VII)

- States should be given at least two years to submit state plans, and in some circumstances three years may be more appropriate because the determination of emission limits for each EGU are highly unit-specific and very fact intensive. Preparation of a model trading rule by EPA that states may opt into will help ease timing burdens.

Mass-Based Emission Limits (Section VIII)

- EPA should allow a state to express the emissions limits for fossil fuel-fired EGUs as a mass-based emission rate (e.g., tons of CO_2 per year), and any model trading rule prepared by EPA should use a mass-based emissions rate of tons per year.

Current Options for Systems of Emission Reduction for Existing EGUs (Section IX)

- While there are several promising technologies on the horizon that will help limit GHG emissions from EGUs, these emerging technologies have not yet crossed the regulatory threshold of being "adequately demonstrated" in the power sector, as required by the CAA.
  - Carbon capture, utilization, and sequestration ("CCUS") has not had sufficient experience in commercial duty and is not yet ready for widespread deployment. There are many issues that remain including geographic and site constraints, access to water, parasitic load, and cost.

- CCUS for NGCCs is still in the engineering phase, with the closest project at least three years away from any operation.
- CCUS for coal-fired EGUs has limited experience in commercial operation and has a very high cost.
- Natural gas co-firing is not sufficiently available across the fleet. For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost-prohibitive because of the cost of gaining access. Even those EGUs with co-firing capability may not have access to sufficient quantities of natural gas. Natural gas repowering would pose a significant legal risk that it would not be permissible under the CAA because it would "redefine the source."
- Operating efficiency improvements are a proven system of emission reduction for coal-fired EGUs. The potential for operating efficiency improvements at gas-fired EGUs is more limited, and any emission reduction associated with those improvements is relatively small. EPA needs to address potential New Source Review ("NSR") issues that could arise with regard to efficiency improvements. There are limited technologies for operating efficiency improvements at combustion turbines.
- Hydrogen combustion is a promising technology that is not yet ready to be deployed throughout the industry. Many issues need to be resolved including increased NOx emissions, efficiency impacts, storage issues, safety concerns, how equipment will respond to higher flame temperature, and whether there can be a consistent supply of low-carbon hydrogen.

NSPS for Fossil Fuel-Fired EGUs (Section X)

- EPA should recognize the valuable role that NGCC and simple cycle combustion turbines play in the energy transition and the need for these units to provide reliable baseload generation, as well as to backup intermittent renewable generation. EPA should not make the construction of these units too burdensome or expensive as doing so could slow down the energy transition.
    - EPA should retain the subcategorization of baseload and non-baseload for combustion turbines.
    - The best system of emission reduction ("BSER") for new or reconstructed baseload combustion turbines should remain "modern efficient NGCC technology." The emission limitation should be revised, however, because the technology has improved since the NSPS was first promulgated.
    - The BSER for non-baseload combustion turbines (both for natural gas-fired and multi-fuel units), which is currently the use of clean fuels, and the related emission limitations achievable with that BSER should remain unchanged.
- Because there are no plans to construct any new coal-fired EGUs (or modify any existing coal-fired EGUs) in the United States, PGen does not have any recommendations for EPA on those NSPS.

III. PGen's Recommended Approach

During PGen's meeting with EPA on November 17, the Agency suggested that it would find it most useful for PGen to set forth an approach that it was recommending rather than simply setting out a set of principles that EPA should follow. In response to this request, PGen recommends that EPA make clear in its emission guideline addressing GHG emissions from existing fossil fuel-fired EGUs that states have the authority to offer a wide array of flexible options to assist existing sources in meeting their performance standards. The types of options that EPA should make clear that states can offer should include emissions averaging and cap-and-trade, as well as equating any rate-based emission limitations to a mass-based emission rate.

PGen recommends that EPA follow the approach that it took with CAMR and develop a model rule that incorporates these types of flexible options. EPA should make clear that it would approve any approaches that follow its model language. This would provide certainty to states, would ease the burdens on states with regard to preparation of state plans, and would provide a mechanism where states that want to participate in a cap-and-trade program with other states would have an easy way to do so.

Ensuring maximum flexibility in terms of compliance strategies will ease a lot of the issues that exist at this time with regard to regulation of GHG emissions from existing fossil fuel-fired EGUs. For example, a cap-and-trade program will help preserve reliability during the energy transition and will help keep electricity affordable. Perhaps most importantly, a cap-and-trade program will help by providing time for technologies that are showing promise to mature and for funding from the Inflation Reduction Act ("IRA") to be deployed, which will help spur advancements in technology development.

By leaning into compliance flexibility, maximizing its use, and expressly encouraging states to take advantage of these mechanisms, owners and operators of fossil fuel-fired EGUs will have the ability to continue to operate on a limited basis those units that are needed for reliability purposes. It is also a well-established fact that cap-and-trade programs minimize cost, which will help keep electricity affordable.

PGen's recommended approach is discussed in more detail in Section V below.

IV. Preserving Reliability and Affordability During the Energy Transition[7]

As EPA works on the proposed rulemakings to regulate GHG emissions from EGUs, it needs to recognize that these regulations will come into effect while the electric generating industry is in a period of transition toward increased use of renewable energy and decreasing use of fossil fuel-fired generation. The retirement of coal-fired EGUs has been occurring at a rapid

[7] EPA posted a list of questions on which it was specifically seeking input from stakeholders for this pre-proposal non-rulemaking docket. Questions for Consideration, Docket ID No. EPA-HQ-OAR-2022-0723-0002 ("Questions for Consideration"). This Section relates to Question 4 from that list.

pace. From 2010 to 2019, about 40 percent of U.S. coal generating capacity closed.[8] According to the U.S. Energy Information Administration ("EIA"), 14.9 gigawatts ("GW") of generating capacity is scheduled to retire in the United States in 2022, and all of those retirements are coming from baseload capacity (85 percent from coal, 8 percent from natural gas, and 5 percent from nuclear).[9]

The high pace of coal-fired EGU retirements has strained the grid and threatened reliability. In its 2022-2023 Winter Reliability Assessment, the North American Electric Reliability Corporation ("NERC") expressed concern that "[a] large portion of the North American [bulk power system] is at risk of insufficient electricity supplies during peak winter conditions."[10] For the Texas ERCOT region, NERC says that EPA's coal ash disposal regulations "could impact the availability of two coal-fired generation units (combined total of 1,477 MW) in the last weeks of winter. These units could be important resources during extreme conditions…."[11] Similarly, MISO (the independent system operator in the Midwest) has had its reserve margins fall by over 5 percent since last winter because of nuclear and coal-fired EGU retirement.[12] One of NERC's recommendations is that "regulators should … take steps to delay imminent generation retirements if essential to reliability."[13] NERC's 2022 Summer Reliability Assessment expressed similar reliability concerns, especially in MISO.[14]

The concerns about reliability will only increase in the next few years as many more retirements of the remaining coal-fired EGUs are expected. The EIA reports that 28% of the remaining coal-fired EGUs will retire by 2035,[15] with nearly all of those retirements taking place by the end of 2029.[16] Nearly 10,000 MW will be retired in 2028 alone, being driven primarily by compliance with EPA's Effluent Limitations Guidelines, which limit waste water discharges from power plants.[17] The EIA says that cost of compliance with that rule, which involve

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[8] Phys.org, *50 US coal power plants shut under Trump* (May 9, 2019), https://phys.org/news/2019-05-coal-power-trump.html (noting the closure of 289 plants between 2010 and 2019).

[9] EIA, Today in Energy, *Coal will account for 85% of U.S. electric generating capacity retirements in 2022* (Jan. 11, 2022), https://www.eia.gov/todayinenergy/detail.php?id=50838.

[10] NERC, 2022-2023 Winter Reliability Assessment at 4 (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

[11] *Id.*

[12] *Id.*

[13] *Id.* at 5.

[14] NERC, 2022 Summer Reliability Assessment at 4 (May 2022) (noting MISO is at a "high risk of energy emergencies during peak summer conditions"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

[15] EIA, Today in Energy, *Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035* (Dec. 15, 2021), https://www.eia.gov/todayinenergy/detail.php?id=50658.

[16] EIA, Today in Energy, *Nearly a quarter of the operating U.S. coal-fired fleet scheduled to retire by 2029* (Nov. 7, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54559.

[17] *Id.*

significant capital investment, is "likely influencing the decision to retire some of these coal-fired units."[18]

In developing the GHG rules for existing sources, EPA should take into account that any regulatory program that requires significant capital investment into coal-fired EGUs will likely hasten the plant's retirement – further straining electric reliability, raising health and safety issues, increasing the cost of electricity, and undermining public support for GHG reducing programs. For this reason, PGen strongly recommends that EPA consider allowing states to exempt from emission limitation requirements in their state plans those existing fossil fuel-fired EGUs that will retire within a reasonable amount of time. Requiring EGUs that are going to be retired soon anyway to comply with section 111(d) emission limitations may hasten their retirement, which in turn could further threaten electric reliability.

Similarly, EPA should also consider allowing states to exempt from emission limitations requirements in their state plans any existing fossil fuel-fired EGUs that operate only rarely for the purpose of stabilizing the grid during period of extreme load (such as during periods of excessive cold or heat or when baseload units go offline). These units could be subject to limitations on the amount they may operate in a given year. As discussed further in Section IX.C.1, EPA also should consider for any coal-fired EGUs that operate as backup generation the effect that low load will have on any heat rate efficiency for the unit, particularly if heat rate efficiency improvements are part of EPA's emission guideline.

Allowing states to make these exemption determinations in their state plans is permissible under the CAA. Section 111(d) specifically mandates that EPA must allow states to take the remaining useful life of an existing source into account in applying a standard of performance to that source. States should be able to require less stringent emission limitations (including an exemption) for EGUs that are not expected to operate much longer. Owners and operators of these EGUs will not put significant monetary resources into units that they plan to retire in the near future. If the emission guideline and state plans require such an investment, these EGUs will be prematurely retired, and this will have a deleterious impact on electric reliability.

Finally, as EPA works on its GHG rules for new, modified, and existing EGUs, it should coordinate and collaborate with its other peer agencies, such as the Department of Energy ("DOE") and the Federal Energy Regulatory Commission, to ensure that electricity remains reliable and affordable. EPA's rulemaking should not occur in a vacuum. Moreover, EPA needs to make sure that states have adequate time to consult with their regulators, such as public service commissions, for the purpose of ensuring reliability and affordability as well.

V. The Critical Importance of Flexibility in Compliance[19]

EPA recently reconsidered its interpretation of section 111(d) and has found that this provision "does not, by its terms, preclude states from having flexibility in determining which

[18] *Id.*

[19] This Section generally responds to Questions 3b and 3c in the Questions for Consideration.

measures will best achieve compliance with the EPA's emission guidelines."[20] Indeed, the Agency has made clear that states may "achieve the requisite emission limitation through the aggregate reductions from their sources," including by imposing "standards that permit their sources to comply via methods such as trading or averaging."[21] PGen agrees with EPA's position on this important point and urges EPA to make compliance flexibility a centerpiece of its emission guideline.

Any final emission guideline should recognize the states' authority to provide flexible options that existing fossil fuel-fired EGUs may use for compliance, including the authority to allow emissions averaging and emissions trading. As EPA has recognized in promoting flexible compliance under CAA regulatory programs, including section 111(d), flexibility allows sources to achieve the CAA's environmental goals while minimizing cost.[22] Compliance flexibility also provides incentives for sources to pursue additional emission reductions beyond those required by a rule.

The Supreme Court has made clear that an emissions limit must be "based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly."[23] Once that occurs, however, EPA and the states may allow flexibility in meeting an emissions cap through cap-and-trade and other measures. The plain language of section 111(d) directs EPA to prescribe regulations establishing a procedure similar to that provided in section 110 under which states shall submit plans which "(A) establish[] standards of performance" – a defined term – and "(B) provide[] for the implementation and enforcement of such standards."[24] This makes clear that the *implementation* of the standard of performance is separate from the *setting* of the standard itself. Moreover, section 110 specifically recognizes state authority to provide for implementation of standards by including in state plans "other control measures, means, or techniques," including "economic incentives."[25] The Supreme Court has held that "necessary or appropriate" measures to meet a standard reflect consideration of costs and benefits.[26]

EPA should make clear in its emission guideline that states may offer flexible options to assist existing sources in meeting the performance standards. Some of the types of flexible options that states might want to consider (and that EPA should make clear would be acceptable) include averaging among units at a plant, averaging among units within a corporate fleet (i.e., units with the same owner), averaging among non-affiliated units within the state, or averaging or trading among affected units in different states.

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[20] 87 Fed. Reg. 74,702, 74,812 (Dec. 6, 2022).

[21] *Id.* at 74,813.

[22] *See Michigan v. EPA*, 135 S. Ct. 2699 (2015) (recognizing importance of considering cost in agency rulemaking).

[23] *West Virginia v. EPA*, 142 S. Ct. 2587, 2610 (2022). The Clean Power Plan ran afoul of this principle because a source could not achieve the emission limitation on its own.

[24] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1).

[25] *Id.* § 110(a)(2)(A), 42 U.S.C. § 7410(a)(2)(A).

[26] *Michigan v. EPA*, 135 S. Ct. at 2707-08.

Indeed, PGen believes that EPA should encourage states to exercise this authority as it did in 2005 in CAMR.[27] In that rule, the "system of emission reduction" that EPA identified, and that was then used to set the emission guidelines, was based on specific pollution control technology that could be installed at individual sources.[28] EPA then established a trading program as an implementation tool to assist sources in meeting their performance standards. This trading program took the form of a model rule, and states had a choice regarding whether to participate in the trading program.[29] Participation in the trading program was "a fully approvable control strategy for achieving all of the emissions reductions required under the final rule in a more cost-effective manner than other control strategies."[30] States were also permitted to deviate from the model rule in certain respects "to best suit their unique circumstances."[31]

As it did with CAMR, EPA should develop a model rule that suggests how these types of flexible compliance mechanisms could work and should make clear that EPA would approve any approaches that follow its model language. States that choose any such options would benefit from the certainty of automatically approvable state plans (as with CAMR). And for those states that desire to cooperate with other states, this approach would relieve them of the time, legwork, and uncertainty involved in coordinating and negotiating with dozens of other jurisdictions. But even if EPA chooses not to develop a model rule, it should – at a minimum – still make clear that states are permitted to incorporate these types of post-standard-setting flexible implementation mechanisms into their state programs.[32]

PGen also encourages EPA to consider offering incentives to reward early action and to ensure credits remain for some period of time when units shut down, as has been done in other section 110 implementation rules like the Cross-State Air Pollution Rule, the Clean Air Interstate Rule, and the NOx SIP Call. EPA should want to encourage states to adopt these types of flexible implementation programs. As EPA noted when it proposed CAMR, the Agency's "significant experience" with cap-and-trade programs for utilities has shown that such programs cause emissions to fall *below* the mandated cap, despite increased electric generation, while "maximizing overall cost-effectiveness."[33]

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[27] 70 Fed. Reg. 28,606 (May 18, 2005). The U.S. Court of Appeals for the D.C. Circuit vacated CAMR for reasons having nothing to do with the flexible options that EPA allowed. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[28] 70 Fed. Reg. at 28,617-20, 28,621. The systems of emission reduction that were used to set CAMR's emission guidelines were based on: (1) installing scrubbers and selective catalytic reduction at individual units under the Clean Air Interstate Rule (for the first phase of CAMR); and (2) installing mercury-specific pollution control technologies such as activated carbon injection (for the second phase). *Id.*

[29] *Id.* at 28,624 (noting that "States may elect to participate in an EPA-managed-cap-and-trade program").

[30] *Id.* at 28,625.

[31] *Id.*

[32] EPA did exactly this in its section 111(d) emission guidelines for Large Municipal Waste Combustors. There, EPA said that "[a] State plan may establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxide emission credits." 40 C.F.R. § 60.33b(d)(2); *see also id.* § 60.33b(d)(1) (expressly allowing state plans to allow nitrogen oxide emissions averaging).

[33] 69 Fed. Reg. 4652, 4697 (Jan. 30, 2004); *see also id.* (noting that trading "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces" and that "[s]ource have an incentive to endeavor to reduce their emissions below the number of allowances they receive").

Ensuring that states have maximum flexibility in terms of compliance strategies will result in another significant benefit: namely, reliability. A trading program will allow fossil fuel-fired EGUs that are rarely used to continue to be operated for the purpose of stabilizing the grid during times of peak load (such as during times of extreme heat or cold or because of an extreme weather event) because the owners and operators of those EGUs can forgo significant capital investment in those units and instead buy allowances to cover those units' limited emissions. Flexible compliance also assists with the issue of heat rate improvements deteriorating over time, which is discussed later in Section IX.C.

Finally, as discussed in Section VI below, flexible compliance programs such as cap-and-trade or emissions averaging have been shown to result in significant benefits to environmental justice communities.

VI. <u>**Environmental Justice**</u>[34]

President Biden and his administration, including EPA in particular, have recommitted the federal government to pursuing environmental justice and specifically to addressing it in the rulemaking process.[35] In developing a rule to address GHG emissions from power plants, EPA should recognize the significant negative environmental justice ramifications that could result from a regulation that does not provide adequate compliance flexibility. As explained below, those ramifications include the impacts of unnecessarily costly regulations on environmental justice communities and their access to affordable electricity, as well as the potential for unique harm to environmental justice communities that could flow from a rule that does not adequately protect electric reliability. Moreover, the flexible compliance mechanisms that EPA should adopt, including emission allowance trading, have been shown to further environmental benefits in environmental justice communities as discussed further below.

A. Electricity Prices

As the EIA explains, "[e]lectricity prices generally reflect the cost to build, finance, maintain, and operate power plants and the electricity grid."[36] Power plants costs, which include financing, construction, maintenance, and operating costs, are one of the key factors affecting electricity price. Costs associated with emissions controls are included among these power plant costs and can be significant. Electricity prices increased across all regions of the United States,

[34] This Section generally responds to Question 3c in the Questions for Consideration.

[35] *See, e.g.*, Executive Order 13985 (January 20, 2021), https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-advancing-racial-equity-and-support-for-underserved-communities-through-the-federal-government/; EPA, Guidance on Considering Environmental Justice During the Development of Regulatory Actions (2015), https://www.epa.gov/environmentaljustice/guidance-considering-environmental-justice-during-development-action.

[36] U.S. Energy Information Administration, *Electricity explained: Factors affecting electricity prices*, https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php (emphasis removed).

with an overall average increase of 15 percent between September 2021 and September 2022.[37] These increases disproportionately impact environmental justice communities, which already pay a significant percentage of their income toward energy costs.[38] Further increases due to environmental regulation will only exacerbate this impact.

Regardless of the specific rules governing electric markets, electric rates are set to recover the cost of delivering electricity. Accordingly, any environmental rule that applies to electric generators will result in some additional costs being passed through to electric ratepayers. For example, in its evaluation of the Clean Power Plan, EPA concluded that the emission controls and compliance costs associated with that rule would result in annual costs ranging from $5.5 billion and $7.5 billion in 2020 to between $7.3 billion and $8.8 billion in 2030.[39] EPA concluded that those costs would lead to "a [four] to [seven] percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020."[40]

The costs of new environmental regulation are likely to fall disproportionally on lower-income households and environmental justice communities. Lower-income families are more vulnerable to energy costs than higher-income families because energy represents a larger portion of their household budgets. Increased energy costs mean that these households will have less income to spend on other necessities, like food, housing, and health care. As explained by the National Conference of State Legislatures, studies have shown that environmental justice communities and low-income families pay a significantly higher share of their income in energy costs.[41] Data from the Department of Energy's Low-Income Energy Affordability Data ("LEAD") Tool show that, on average, low-income households pay approximately 9 percent of their income in energy costs, which is three times more than non-low-income households.[42] The American Council for an Energy-Efficient Economy estimates that 25 percent of households have a "high energy burden," defined as above 6 percent of household income.[43] Black,

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[37] U.S. Energy Information Administration, Electric Power Monthly, Table 5.6.A., Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2022 and 2021, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

[38] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

[39] 79 Fed. Reg. 34,830 34,934-34,935 (June 18, 2014) (proposed Clean Power Plan).

[40] *Id*. at 34,948. Testimony at an April 14, 2015 congressional hearing confirmed that the Clean Power Plan, like any other environmental rule with significant compliance costs, would substantially increase electricity costs for ratepayers. One energy economist estimated that rates in thirty-one states could be fifteen percent higher each year than they would have been in the absence of the rule. House of Representatives, Report No. 114–171 at 10 (June 19, 2015), https://www.congress.gov/114/crpt/hrpt171/CRPT-114hrpt171.pdf. State officials similarly testified that the proposed Clean Power Plan could result in "potential increases of [twenty-two to fifty percent] in Florida, and between ten and thirty percent in Kansas. *Id*. at 11.

[41] National Conference of State Legislatures, Energy Justice and the Energy Transition at 1 (2022), https://www.ncsl.org/Portals/1/Documents/energy/EnergyJusticeReport_2021_37639.pdf.

[42] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

[43] American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States (Sept. 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

Indigenous, and People of Color communities "often experience the highest energy burdens when compared to more affluent or white households."[44] These disproportionate energy burdens have significant and lasting negative consequences for those that are impacted: "high energy burdens are associated with inadequate housing conditions and have been found to affect physical and mental health, nutrition, and local economic development."[45] For all of these reasons, new regulations to address GHG emissions should take the energy burden on disadvantaged communities into account.

B. Reliability

Flexibility regarding compliance with a GHG regulatory program could enhance environmental justice values in other ways. In particular, should a rule without adequate compliance flexibility result in electric reliability problems, those problems are most likely to be borne by environmental justice communities. Industrial customers and customers with financial means may install emergency backup generation to manage their electric reliability concerns. These emergency backup units are typically uncontrolled, and frequent use of them could result in worse air quality where they are located, including in already disadvantaged communities located near industry.

The concept of energy justice also "is based on the principle that all people should have a reliable, safe, and affordable source of energy."[46] A regulatory system that allows wealthy and privileged communities to avoid electric reliability problems and that would leave environmental justice communities without a similar remedy would violate environmental and energy justice principles. A flexible cap-and-trade compliance mechanism will likely provide the most efficient and best tested regulatory approach for allowing utilities to ensure electric reliability and protect environmental justice communities in the process.

The need for compliance flexibility to protect reliability and to minimize costs to ratepayers is especially important for environmental justice communities because utilities serving those communities and those with facilities located in disadvantaged areas are often among the smallest electric generating companies and organizations. Electric cooperatives, for instance, are generally among the smallest utilities. According to the National Rural Electric Cooperative Association, electric cooperatives "serve 42 million people, including 92% of persistent poverty counties."[47] Community-owned public power utilities also serve a significant proportion of environmental justice communities and include many smaller generators.[48] Further, an analysis by the American Council for an Energy Efficient Economy found that areas served by investor-

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[44] *Id*. at 2.

[45] *Id*. at 5.

[46] Aladdine Joroff, *Energy Justice: What It Means and How to Integrate It Into State Regulation of Electricity Markets* at 1 (Nov. 2017), https://elpnet.org/sites/default/files/2020-04/energy_justice_-_what_it_means_and_how_to_integrate_it_into_state_regulation_of_electricity_markets.pdf.

[47] National Rural Electric Cooperative Association, Electric Co-op Facts & Figures (Apr. 28, 2022), https://www.electric.coop/electric-cooperative-fact-sheet.

[48] American Public Power Association, 2022 Public Power Statistical Report, https://www.publicpower.org/system/files/documents/2022%20Public%20Power%20Statistical%20Report_0.pdf.

owned utilities, including in some of the nation's largest cities, include customers who face significant energy burdens and that utilities needed significant assistance to better serve these communities.[49] All of these constraints, especially for smaller utilities with limited generation assets, result in decreased options for reducing the costs and impacts of any significant new regulatory program on underserved communities. Flexible compliance mechanisms, like allowance trading, can help to alleviate these problems.

C. Cap-and Trade Evaluations

Allowing affected facilities to comply with a new GHG standard through an emissions allowance trading program is likely the most direct and legally sound approach for providing the necessary compliance flexibility. It is also clear from recent evaluations of cap-and-trade policies that are similar to what EPA might adopt to address power plant GHG emissions, that providing for compliance through allowance trading is unlikely to have negative environmental justice impacts and, in fact, should achieve the opposite.

The California Air Resources Board ("CARB") has, for instance, supported its Carbon Cap-and Trade Program with significant analysis of environmental justice issues. Based on the results of several studies, CARB has concluded that "[t]here is no evidence that the Cap-and-Trade Program has exacerbated local air pollution in environmental justice communities."[50] On the contrary, CARB explains that a 2020 study from the University of California, Santa Barbara found that air quality in environmental justice communities with large cap-and-trade facilities improved more than air quality in wealthier neighborhoods since the state began implementing the Cap-and-Trade Program.[51] That result was confirmed by a 2022 study by the California Office of Environmental Health and Hazard Assessment, which found that "the greatest beneficiaries of reduced emissions from facilities subject to the Cap-and-Trade Program have been disadvantaged communities and communities of color in California."[52]

Setting aside the benefits to environmental justice communities achieved through CARB's GHG Cap-and-Trade Program, CARB makes clear that the most effective policy options for further addressing environmental justice include regulation of GHG emissions through allowance trading while addressing local air pollution issues affecting environmental justice communities pursuant to authorities specifically designed to address localized pollution.[53] This is a reasonable approach to these issues, given that the purpose of the Cap-and-Trade Program is reduction of GHGs, which have no significant localized air quality effect and no direct, exposure-based impact on disadvantaged communities.

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[49] A. Drehobl and L. Ross, American Council for an Energy-Efficient Economy, *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities* at 25-29 (Apr. 2016), https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf.

[50] CARB, FAQ Cap-and-Trade Program, https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

[51] *Id*.

[52] *Id*.

[53] *Id*.

EPA itself similarly concluded that an emission allowance cap-and-trade program will not adversely affect environmental justice communities in its proposed Good Neighbor Plan for the 2015 national ambient air quality standards ("NAAQS") for ozone.[54] The proposed Good Neighbor Plan is based in significant part on an ozone season emission trading program for nitrogen oxide emissions from electric generating units. The proposed rule also includes one of EPA's first and most significant assessments of the environmental justice impacts of a major regulatory program since the adoption of the Biden administration's new policies on promoting environmental justice and ensuring that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies."[55] To evaluate potential environmental justice concerns, EPA performed two types of analyses: proximity analyses and exposure analyses.[56] The analyses were intended to determine baseline environmental justice impacts and potential environmental justice concerns "after implementation of the regulatory options under consideration" and "whether potential EJ [environmental justice] concerns will be created or mitigated compared to the baseline."[57]

EPA's analysis resulted in the following proposed findings: (1) environmental justice communities are disproportionately exposed to ozone under baseline conditions; (2) when comparing across policy options, ozone concentrations are reduced across all populations evaluated; and (3) populations experiencing disproportionate impacts in the baseline will continue to experience "similar disproportionate … exposures under the proposed rulemaking, although to a lesser absolute extent as the action described in this proposed rule is expected to lower ozone in many areas, including residual ozone nonattainment areas."[58] As a result, EPA does not "predict that potential [environmental justice] concerns related to … [ozone] concentrations will be created or mitigated as compared to the baseline."[59] Accordingly, even when the pollutant at issue does have a localized effect, which is not the case for GHGs, EPA has determined based on quantitative analysis that an emission allowance cap-and-trade program will not adversely affect environmental justice values.

Based on California's and EPA's experiences, there is a strong basis for concluding that a regulatory program that adopts an emission allowance trading compliance mechanism will have environmental benefits for environmental justice communities and potentially reduce disproportionate impacts in addition to net impacts. Such a program could achieve that goal while avoiding negative consequences for disadvantaged communities that would result from increased electricity prices and loss of electric reliability in communities that already experience disproportionate energy burdens. For these reasons, EPA should carefully consider making its program to address GHG emissions from EGUs as flexible as possible, incorporating cap-and-

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[54] 87 Fed. Reg. 20,036 (Apr. 6, 2022).

[55] *Id*. at 20,153.

[56] *Id*.

[57] *Id*.

[58] *Id*. at 20,154.

[59] *Id*.

trade, emissions averaging, and any other measures that will help ease the burden on disadvantaged communities.

VII. **Timing of State Plan Submissions**[60]

EPA revised the regulations governing the timing of state plan submissions, the timing of EPA action on those state plans, and the timing of when EPA must issue a federal plan as part of its Affordable Clean Energy ("ACE") rule.[61] These revisions were vacated by the D.C. Circuit,[62] leaving no regulations that currently govern these actions for emission guidelines promulgated after July 8, 2019.[63]

Recently, EPA issued a supplemental proposed rule to regulate methane emissions for the oil and gas sector and proposed to provide states 18 months to submit state plans under that proposal.[64] PGen respectfully suggests that states need a minimum of at least two years to prepare state plans for existing EGUs. Depending on how individualized the application of the emission guideline is to individual units, three years might be more appropriate because the determination of emission limits for each EGU are highly unit-specific and because the preparation of a plan will take time and be very fact intensive. This is not a "one-size-fits-all" analysis.

The timing issue also provides additional support for PGen's recommended approach of EPA issuing a model trading rule, which states could opt into and that would satisfy the requirements of EPA's emission guideline. If such a model rule is provided, states could opt into that rule very quickly. But for those states that might not want to opt into a model trading rule, sufficient time needs to be provided.

VIII. **Mass-Based Emission Limits**[65]

EPA has specifically asked as part of this pre-proposal non-rulemaking docket for stakeholders to discuss what options the Agency should be considering when it expresses proposed emissions limits for fossil fuel-fired EGUs.[66] EPA notes that performance standards under section 111 "have typically taken the form of a 'rate-based' limit expressed in terms of a quantity of pollution per unit of product produced or per unit of energy consumed," such as pounds per kilowatt hour (lb/kWh) or pounds per British thermal units (lb/mmBtu).[67] PGen

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[60] This Section generally responds to the portion of Question 3a (involving timing of state plans) in the Questions for Consideration.

[61] 84 Fed. Reg. 32,520, 32,564-71 (July 8, 2019).

[62] *American Lung Ass'n v. EPA*, 985 F.3d 914, 991 (D.C. Cir. 2021).

[63] 87 Fed. Reg. at 74,831.

[64] *Id.* at 74,831-32.

[65] This Section generally responds to Question 2 of the Questions for Consideration.

[66] Questions for Consideration, Question No. 2.

[67] *Id.*

suggests that in the emission guideline, EPA should allow a state to express the emission limits as a mass-based emission rate (e.g., tons of CO_2 per year). PGen also encourages EPA, if it issues a model trading rule, to use a mass-based emission rate of tons per year in any such rule.

Expressing the emission limit as a mass-based rate has numerous advantages. First, it makes it easier for states to incorporate flexible compliance mechanisms such as emissions averaging or cap-and-trade programs into their state plans. Several states already have carbon trading programs with mass-based caps,[68] and the ability of those states to incorporate those programs into a trading program designed under section 111(d) would be beneficial. Additionally, EGUs have a lot of experience and familiarity with cap-and-trade programs (such as the Acid Rain Program and the Cross-State Air Pollution Rule) that are mass-based. Staying with an approach that is proven and with which EGUs have significant experience makes sense.

Second, it eases reliability concerns because older, less efficient fossil fuel-fired EGUs that are rarely used can be available for use when needed (i.e., in times of extreme heat or cold) when the grid is strained. For example, if a unit's emission limit is expressed as tons per year, these types of units can run for short periods of time as needed to ease the strain on the grid without fear of violating a short-term rate-based limit.

Third, this approach also assists with dealing with the issue of heat rate improvements deteriorating over time. Expressing the emission limitation as tons per year allows a unit to continue to operate as its heat rate deteriorates. Although the unit may need to operate less over the course of a year, it would not have to cease operation (which could happen under a rate-based approach), which could have reliability impacts.

IX. Current Options for Systems of Emission Reduction for Existing EGUs[69]

A. Carbon Capture, Utilization, and Storage

CCUS is a very promising technology that is making advancements through a variety of pilot projects throughout the United States. Some PGen members are actively investigating the feasibility of CCUS at some of their facilities and hope to be able to rely on this technology in the future to reduce GHG emissions. While progress is being made, however, the technology has not yet been developed enough in the power sector to cross the regulatory threshold into being "adequately demonstrated," as required for any BSER under the CAA. PGen members have concerns that there is insufficient experience at this time with CCUS in commercial operation to find that the technology is currently feasible or reliable for widespread application. And, even if the technology were ready for more widespread deployment, several issues remain that technological development cannot resolve, including geographical constraints, access to water, parasitic load, and cost.

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[68] *See, e.g.*, Regional Greenhouse Gas Initiative, https://www.rggi.org/ (CO_2 cap-and-trade in the eastern portion of the United States covering EGUs in 14 states); California Cap-and-Trade Program, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program (CO_2 cap-and-trade program in California that covers EGUs and other industries).

[69] This Section generally responds to Question No. 1 from the Questions for Consideration.

1. Geographic and Site Limitations

CCUS technology is distinct from other emission controls in that its application requires that suitable geological formations for underground storage of captured CO_2, such as deep saline reservoirs, or CO_2 transport pipelines be available nearby. The reality is, however, that many parts of the country have no assessed capacity for CO_2 storage, and even those that do may not be adequate for large-scale CO_2 sequestration when examined on a site-by-site basis.

As shown by Department of Energy ("DOE") and U.S. Geological Survey ("USGS") surveys, potential repository sites are not evenly distributed throughout the United States, and many locations throughout the country lack suitable geological conditions for carbon storage.[70] The USGS National Assessment concludes that fully two-thirds of the technically accessible storage resources in the United States are confined to the Coastal Plains region, with 91 percent of that total limited to a single basin.[71] Another tenth of the nation's potential storage capacity is in Alaska, almost all of which is confined to the remote North Slope.[72] In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard, contains less than 1 percent of the nation's storage capacity.[73]

Moreover, the CO_2 storage at any specific site will not be known until the site is assessed for specific criteria. As DOE noted in the first edition of its North American Carbon Storage Atlas, "[i]t is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and that no major faults exist."[74] The North American Carbon Storage Atlas also cites the importance of documenting the CO_2 storage capacity, the "injectivity," and the ability of the porous rock to permanently trap CO_2. All of these criteria are necessary to evaluate the storage potential of a site.[75] Other site-specific items that need to be considered include land-management or regulatory restrictions, or whether the basin contains freshwater that would restrict its use for CO_2 storage.[76]

Furthermore, the estimates presented in the DOE and USGS reports are uncertain, "high level" assessments of potential storage resources, and actual storage capacity is likely to be significantly lower than the estimates presented in these studies. USGS researchers have

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[70] *See* U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Storage Atlas and Data Resources*, https://netl.doe.gov/carbon-management/carbon-storage/atlas-data ("NETL Carbon Storage Atlas"); U.S. Department of the Interior, U.S. Geological Survey, Circular 1386, Version 1.1, *National Assessment of Geologic Carbon Dioxide Storage Resources—Results* (Sept. 2013), https://pubs.usgs.gov/circ/1386/pdf/circular1386_508.pdf ("USGS National Assessment").

[71] USGS National Assessment at 3 (Fig. 1), 15.

[72] *Id.*

[73] *Id.* at 3 (Fig 1).

[74] *The North American Carbon Storage Atlas – 2012* (First Edition), Slide 18, https://www.slideshare.net/dove000/nacsa2012webversion-43472232 ("North American Carbon Storage Atlas").

[75] *Id.*

[76] USGS National Assessment at 15.

expressed concern that due to issues such as reservoir pressure limitations, boundaries on migration of CO_2, and acceptable injection rates over time, "it is likely that only a fraction" of the high-level estimated technically accessible CO_2 storage resources could be available.[77] A formation may have one or more fractures in the caprock or may have well penetrations. A site may have sufficient porosity but low permeability. Current information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to determine how the CO_2 plume will spread and to address displacement of underground fluids. Settlement of CO_2 and displacement of underground fluids factor into the property rights that must be pre-arranged for sequestration. These critical issues require costly, potentially time-consuming research and resolution that takes several years; it can take several years simply to evaluate a site for CO_2 storage potential. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to begin the process all over again with additional time and money.

For example, in the late 2000s, several entities (including PGen members) participated in a CO_2 storage pilot project to investigate the suitability of a formation in the Colorado Plateau region of northeastern Arizona.[78] Five candidate project sites were evaluated prior to the selection of a final test site near Holbrook, Arizona. The project participants held meetings to inform the local community about the project beginning in 2007, obtained the necessary state and federal permits for well drilling and CO_2 injection in 2008-2009, and completed the 3,800 foot well in 2009. After investing over \$5.7 million and several years on the project, the participants found that the geological formation had insufficient permeability to proceed with CO_2 injection, and the project was discontinued.[79]

Suitable sites for enhanced oil recovery ("EOR") are similarly limited and uncertain. EOR sites are unevenly distributed across the country. The DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration.[80] Moreover, as with sequestration, several years of subsurface feature characterization may be required before a site can be assessed as suitable for EOR. These limits are particularly significant because the only commercial utility applications of CCUS to date that could be cost-justified have had to rely on EOR. The reliance on EOR, however, renders the operation volatile—as can be seen from the Petra Nova project in Texas, which ceased operations because of an economic downturn at the beginning of the COVID-19 pandemic and has never resumed operation.[81]

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[77] *See* Steven T. Anderson, *Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review*, 26:2 NATIONAL RESOURCES RESEARCH 137-59 (Apr. 2017), https://link.springer.com/article/10.1007/s11053-016-9310-7; Steven T. Anderson, *Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review*, 26:1 Natural Resources Research 89-112 (Jan. 2017), https://link.springer.com/article/10.1007/s11053-016-9303-6.

[78] DOE provided 80.5 percent of the overall funding for this project. *See* West Coast Regional Carbon Sequestration Partnership ("WESTCARB"), *Factsheet for Partnership Field Validation Test (Rev. 10-28-09)* at 5, http://www.westcarb.org/pdfs/FACTSHEET_AZPilot.pdf.

[79] *See* WESTCARB, "Arizona Utilities CO_2 Storage Pilot—Cholla Site," http://www.westcarb.org/AZ_pilot_cholla.html.

[80] North American Carbon Storage Atlas at 25 (estimating that 250 billion tons of CO_2 can be used for EOR and thus stored, which is about 10% of the capacity estimated for deep saline sequestration).

[81] *See* NRG, Petra Nova: Carbon capture and the future of coal power, https://www.nrg.com/case-studies/petra-nova.html (noting that the plant "has been impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil" and that "[g]iven the state of oil markets, in May 2020 the carbon capture

In addition, the lack of availability of the needed geographic criteria cannot be easily solved by the construction of pipelines to move the separated gas to areas of the country that can store the CO_2. There are many hurdles to pipeline construction. First, it is extremely expensive; current pipeline projects have cost between $5-10 million per mile of pipe. Second, pipeline projects face significant opposition from the public and require extensive permitting that is not easily or quickly obtained.[82]

Finally, even if there is a way to store the separated CO_2 (either onsite or by pipeline to a suitable site), CCUS may not be able to be installed on an existing EGU because of space constraints at the plant. A carbon capture facility is big and requires a very large amount of land to be available for its construction. Many existing EGUs do not have the land available at the plant to construct the carbon capture facility, particularly in urban areas.

2. Water Constraints

It is well recognized that CCUS requires significant water for process operation. As EPA has acknowledged, "[a]ll [CCUS] systems that are currently available require substantial amounts of water to operate," which "limit[s] the geographic availability of potential future [CCUS] construction to areas of the country with sufficient water resources."[83] Like sequestration, water resources for use in CCUS are severely limited in some parts of the country.

The role of water consumption has always been a key consideration in the siting and design of coal-fired EGUs. In a 1980 EPA study addressing concerns for power plant siting in Wisconsin, residents in six geographical areas consistently ranked water issues as one of the highest concerns.[84] In arid parts of the country, EGU owners have been able to employ less water-intensive designs, such as the use of dry cooling and "dry" scrubbers. Less water-intensive technology is not available for CCUS, which makes its use infeasible in arid parts of the country.

3. Parasitic Load

There is a significant parasitic load associated with the operation of CCUS equipment that is approximately 20 percent of a power plant's capacity.[85] As discussed above in Section IV, the energy transition has resulted in the electricity grid in the United States becoming strained, with reliability being increasingly threatened. Installing CCUS on existing fossil fuel-fired EGUs

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facility was placed in reserve shutdown status to allow it to be brought back online when economic conditions improve").

[82] Any flexibilities that can be provided through the National Environmental Policy Act process to expedite permitting of projects would be useful for compliance with EPA's GHG reduction programs under section 111.

[83] 83 Fed. Reg. 65,424, 65,443 (Dec. 20, 2018); *see also generally id.* at 65,442-44.

[84] EPA, EPA-600/3-80-004, *Citizen Concern with Power Plant Siting: Wisconsin Power Plant Impact Study* (Jan. 1980).

[85] Congressional Research Service, *Carbon Capture and Sequestration (CCS) in the United States* at 2 (Oct. 5, 2022), https://sgp.fas.org/crs/misc/R44902.pdf (citing Howard J. Herzog, Edward S. Rubin, and Gary T. Rochelle, "Comment on 'Reassessing the Efficiency Penalty from Carbon Capture in Coal-Fired Power Plants," *Environmental Science and Technology*, vol. 50 (May 12, 2016), pp. 6112-13).

will exacerbate this reliability problem because approximately one-fifth of the energy being generated will now be needed to power the CCUS technology at power plants rather than being available to the consumer.

4. Cost

CCUS is an expensive technology. Congress recently made numerous changes to Section 45Q of the Internal Revenue Code in the IRA that have the effect of increasing the tax credits available for carbon sequestration. Under the IRA, projects that are placed in service after December 31, 2022, may receive a credit of $85 per ton for CO_2 disposed of in secure geologic storage and $60 per ton of CO_2 used for EOR and disposed of in secure geologic storage or utilized in a qualified manner.[86] This is a significant increase from the amounts previously available for units placed in service before 2023.

While these additional tax credits should help address the cost issue, there remains significant risk associated with CCUS construction. As discussed further in the next sub-section (Section IX.A.5), although promising, CCUS technology is not yet commercially demonstrated. The Section 45Q tax credits available through the IRA may be taken *only* if the facility is able to capture a minimum amount of CO_2. An electric generating facility must capture at least 18,750 tons of CO_2 per year and have a capture design capacity that is at least 75 percent of the unit's baseline carbon oxide production.[87] Because of the current nascent state of the technology, there is risk that the technology may not work, and if that occurs, then the EGU will not be eligible to receive the tax credits that help offset some of the significant costs. This risk is not negligible or theoretical. A CCUS project at an EGU in Mississippi never worked properly. As costs increased $4 billion over the projected budget,[88] Mississippi regulators ultimately ordered the plant to run without the CCUS technology.[89]

5. Status of CCUS Technology Development

(a) NGCCs

There are currently six NGCC projects that are the subject of detailed Front-End Engineering and Design ("FEED") studies with DOE.[90] None of these projects is constructed or operating. Indeed, four of the projects are still in the state of detailed engineering studies; for two of the projects, engineering has only just started. The project that is the furthest along is the Elk Hills project where the owner completed a study in early 2022 and is pursuing a second, more

[86] Pub. L. No. 117-169, § 13104(c).

[87] *Id.* § 13104(a).

[88] Katie Fehrenbacher, *Carbon Capture Suffers a Huge Setback as Kemper Plant Suspends Work* (June 29, 2017), https://www.greentechmedia.com/articles/read/carbon-capture-suffers-a-huge-setback-as-kemper-plant-suspends-work.

[89] E&E News, EnergyWire, *The Kemper project just collapsed. What it signifies for CCS* (Oct. 26, 2021), https://www.eenews.net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

[90] The projects are: Golden Spread/Mustang; Panda/Sherman; Elk Hills; Daniel Unit 4; Barry Unit 6; and Calpine Deer Park.

detailed examination. Even the Elk Hills project, however, is at least three years away from any operation.

Available cost information on these projects is not comparable or not available because some of the projects are in such a nascent stage. The information that is available shows that costs remain prohibitive.

Risks also exist that could compromise reliable operation (and thus threaten the ability to obtain Section 45Q tax credits as discussed above). For CCUS processes that are absorption-based (all but one of the pilot projects), there are issues with the longevity of the solvent, the complexity of material handling and liquid processing, and water consumption. For the one pilot project using a membrane-based process, there are issues with membrane integrity and gas pressure drop.

Additional information regarding the status of CCUS technology for NGCC units can be found in a technical discussion paper authored by J.E. Cichanowicz in January 2022 entitled "2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation." This report is attached to these comments as Attachment A.

(b) Coal-Fired EGUs

There are two CCUS projects at power generating plants in North America that have actually operated: the SaskPower Boundary Dam Unit 3 project in Saskatchewan, Canada; and the NRG Petra Nova project near Houston, Texas. Both of these projects involved retrofitting coal-fired EGUs with CCUS equipment. While both projects have been noted as examples of CCUS technology, they have also been criticized for high costs relative to other low-carbon technologies for electricity generation and for sequestering CO_2 via EOR.[91]

The Boundary Dam project has had technical difficulties and has been underperforming. In 2021, the plant captured 43 percent less CO_2 than it had the year before. SaskPower attributed this decrease to "challenges with the main CO_2 compressor motor" that forced the CCUS part of the plant to go offline for multiple months in 2021.[92] The company's data for 2021 show that the CCUS facility is capturing only approximately 44 percent of its 90 percent maximum capacity – meaning more than half of the plant's CO_2 emissions are not being captured.[93]

The Petra Nova project has also encountered problems. The plant, which began operation in January 2017, was designed to capture 33 percent of the CO_2 emissions from one of the units at NRG's W.A. Parish facility. The facility missed this target by about 17 percent, capturing 3.8 million short tons of CO_2 during its first three years of operation, which was less than the 4.6

[91] *See, e.g.*, Food & Water Watch, *Top 5 Reasons Carbon Capture and Storage (CCS) Is Bogus* (July 20, 2021), https://www.foodandwaterwatch.org/2021/07/20/top-5-reasons-carbon-capture-and-storage-ccs-is-bogus/.

[92] E&E News, Energy Wire, *CCS 'red flag?' World's sole coal project hits snag* (Jan. 10, 2022), https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/.

[93] *Id.*

million short tons that had been expected to be captured.[94] During the time the facility operated, it experienced outages on 367 days, with the CCUS facility accounting for more than one-fourth of those outages.[95] The project was also dependent on oil prices to be economically viable. The project was "impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil," and NRG placed the Petra Nova project in reserve shutdown status on May 1, 2020.[96] The project has not operated since that time, and NRG has not announced any plans to bring it back online.

There are some planned pilot projects for coal-fired EGUs that have not yet become operational. Additional information on those projects is included in the technical report attached to these comments as Attachment A.

B. Natural Gas Co-Firing and Repowering

Natural gas co-firing is not sufficiently available across the fleet. In 2017, only about one-third of coal-fired EGUs co-fired with *any* amount of natural gas.[97] That number has not changed substantially since that time. Of these units, only four percent actually co-fire significant amounts of natural gas for the purpose of generating electricity.[98] The vast majority of EGUs that have co-firing capability use the natural gas at very low levels for the purposes of starting up the boiler or holding it in "warm standby." For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost prohibitive because the cost of gaining access is approximately $5 to $10 million per mile of pipeline required.

For those facilities that can co-fire, an additional challenge may be acquiring sufficient natural gas to co-fire at higher rates on a consistent basis. The requirement to co-fire natural gas in significant quantities would require the fuel to be available at all times (called "firm" access), which is even more expensive and less available than the non-firm form of access that is currently far more common at existing coal-fired EGUs.[99] Existing pipeline infrastructure to the plant may be unable to accommodate greater gas delivery, or pipeline gas pressure may be too low to deliver additional gas to the property line. Further, gas is often unavailable at certain times of the year, which could result in a reliability problem.[100] Whether co-firing is viable ultimately requires a site-by-site analysis.

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[94] Reuters, *Problems plagued U.S. CO_2 capture project before shutdown: document* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8.

[95] *Id.*

[96] NRG, Petra Nova, Carbon capture and the future of coal power, https://www.nrg.com/case-studies/petra-nova.html.

[97] 84 Fed. Reg. at 32,544.

[98] *Id.*

[99] Comments of Great River Energy at 3 (Nov. 2, 2018), available in the docket for the ACE Rule at EPA-HQ-OAR-2017-0355-23734.

[100] Comments of Duke Energy Business Services at 12-13 (Nov. 9, 2018), available in the docket for the ACE Rule at EPA-HQ-OAR-2017-0355-24821.

PGen respectfully suggests that the more efficient use of natural gas would be as fuel for underutilized gas-fired EGUs rather than for co-firing at less efficient coal-fired EGUs. EPA has previously recognized this fact and should do so again.[101]

Finally, natural gas repowering – where a coal-fired boiler is replaced by a natural gas-fired turbine – should not be considered by EPA. Requiring this option would pose a significant risk that a court might overturn the rule because this could be considered "redefining the source," which is not permissible under the CAA.[102] The industry needs stable, durable regulatory policy that is not subject to being overturned, as it allows for better long-term planning.

C. Operating efficiency improvements

1. Coal-Fired EGUs

Heat rate improvements or operating efficiency improvements are a proven system of emission reduction for coal-fired EGUs. Heat rate improvements can effectively reduce a unit's CO_2 emission rate by reducing the amount of heat needed to produce a given unit of electricity, thereby reducing the amount of fuel combusted (and CO_2 emitted) as a function of output. Many heat rate improvement measures are available at a reasonable cost. In fact, because increased efficiency allows coal-fired EGUs to produce the same amount of electricity by combusting less fuel, some of these measures can yield reduced fuel costs, although savings are generally not sufficient to offset the cost of implementing them. While the potential improvement in heat rate at each individual unit varies significantly, coal-fired units can generally implement measures that maintain efficiency and minimize the effects of equipment degradation on the unit's heat rate over time.

Owners of coal-fired utility boilers have extensive experience implementing heat rate improvements because of economic incentives (and in some cases, legal obligations) to operate as efficiently as possible. Many owners of coal-fired EGUs operate their generating resources based on security constrained economic dispatch, in which (subject to reliability and security constraints) the least cost units are dispatched first to keep costs as low as possible. Because keeping costs low involves minimizing fuel costs, it is standard operating practice for coal-fired utility boiler owners and operators to undertake heat rate improvement measures on an ongoing basis to maintain and improve their efficiency.

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[101] 84 Fed. Reg. at 32,544.

[102] *See, e.g.*, *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3 (expressing "doubt" EPA could "requir[e] coal plants to become natural gas plants"); *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2448 (2014) (finding that Best Available Control Technology, which is intertwined with section 111, "cannot be used to order a fundamental redesign of the facility"); *In re Prairie State Generating Co.*, 13 E.A.D. at 25 (holding that it is "long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design"); *Sierra Club v. EPA*, 499 F.3d 653, 655-56 (7th Cir. 2007) (recognizing the choice of fuels is an essential part of a source's purpose and design, and requiring a source to change its design to combust an alternative fuel constitutes redefining the source).

Further, in some cases independent system operators and state public utility commissions even require owners and operators of units within their jurisdiction to implement measures to maintain efficiency. These entities have an interest in ensuring that consumers are paying the lowest rates that they can for electricity and may require units to demonstrate that they are taking steps to ensure that they generate electricity as efficiently and cost-effectively as possible. For example, in Michigan, utility actions regarding the efficiency of fossil fuel-fired EGUs are subject to ongoing review and analysis in general rate cases before the Michigan Public Service Commission.[103]

It is important for EPA to understand, however, that variation in heat rate among EGUs with similar design characteristics is not necessarily indicative of the potential to improve heat rate at a lesser performing EGU. Heat rate can vary for a wide range of reasons, many of which are entirely beyond the control of the EGU's owner or operator, and the fact that observed heat rate may vary among similar units, or vary from year-to-year at an individual EGU, does not automatically indicate that the EGU is not being properly operated or maintained to optimize its efficiency or that there are steps an owner or operator can take to reduce that variability and improve the unit's heat rate. Some of the factors that may influence an EGU's heat rate (and over which an owner or operator has no control) include: geography, elevation, unit size, coal type and quality, pollution controls, cooling system, firing method, and operating load. Accordingly, the existence of heat rate variability is not a valid indicator of the need or opportunity for significant improvement in a unit's heat rate.

Notwithstanding these inherent variabilities, some EGUs do have the ability to improve their heat rate (and thus their CO_2 emission rates), and in these cases, owners and operators should undertake efficiency improvements at those EGUs. It is important to note, however, that the efficiency (and thus the heat rate) of a fossil fuel-fired EGU will degrade over time, and any heat rate-based emission limits must account for that degradation. In situations where a state determines that no further heat rate improvements are appropriate for an EGU and imposes a standard based on "business as usual," the EGU will still need to have a plan to maintain the efficiency of its operations to avoid heat rate increases that could jeopardize compliance with its CO_2 emission limit.

There are numerous technologies that can be employed at coal-fired EGUs to improve heat rate. EPA has explored this issue extensively and developed a list of "candidate technologies" that is a reasonable approach to representing the heat rate improvements that could constitute a system of emission reduction.[104] In contemplating the technologies to consider as potential heat rate and efficiency improvements, EPA (or the states) should express any output-based standards of performance for existing fossil fuel-fired EGUs only in terms of gross output. Any measures that would improve only net heat rate (such as replacing centrifugal flue gas fans

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[103] See Order, Mich. Pub. Serv. Comm'n, Case No. U-15316 & U-15631 (Sept. 15, 2009), https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000000wIHbAAM (ordering regulated electric utilities with fossil fuel generation to file 10-year fossil fuel generation efficiency plans every three years).

[104] 84 Fed. Reg. at 32,537 Table 1. These "candidate technologies" included (1) neural network/intelligent sootblowers; (2) boiler feed pumps; (3) air heater and duct leakage control; (4) variable frequency drives; (5) blade path upgrade (steam turbine); (6) redesign/replace economizer; and (7) additional operating and maintenance practices. *Id.*

with axial fans) should be excluded. The owners and operators of EGUs already routinely take steps to minimize auxiliary load and improve net heat rate as a matter of standard industry practice, given the substantial incentives they have to maximize the amount of electricity produced that is sold to consumers.

Additionally, in recent years, coal-fired EGUs have been incentivized to establish low-load operations that allow coal-fired plants to back down operations when variable and less costly renewable electricity is available. This operation allows the units to remain available for changes in availability of wind or solar resources while avoiding potentially emission intensive startup and shutdown operations. Operation at these low loads greatly reduces the overall emissions of all pollutants; however, this operation is inherently less efficient because low load is not the design point of the unit. As a result, heat rate at low-load operations may not meet more efficient values seen when the unit operates at full load. Thus, should EPA decide to use heat rate efficiency improvement as an indicator or requirement of GHG emission control, PGen encourages EPA to consider accounting for the effect of turndown on heat rate efficiency.

2. Combustion Turbines

Unlike coal-fired EGUs, the identification of a system of emission reduction for stationary combustion turbines (both simple cycle and combined cycle configurations) is more difficult. While there may be some opportunities for improved efficiency at individual EGUs, the potential improvements are relatively small, they have limited availability, and/or they are unreasonably costly. For example, hot gas path upgrades are a possible efficiency improvement that can be implemented at combustion turbines. The benefits of this type of project vary widely but can be significant for older turbines that are not equipped with modern component materials. The problem, however, is that these upgrades are available only to a small portion of the combustion turbine fleet.

Technologies available at coal-fired EGUs are not as viable at combustion turbines. For example, in theory, an NGCC unit could take measures to improve the thermal efficiency of its steam cycle and decrease the overall unit's heat rate. The opportunities for such improvement are limited, however, and prohibitively costly. Additionally, an owner could consider upgrading the steam turbine blade path (as can be done at a coal-fired boiler). The steam turbines designed for application in the steam cycle of an NGCC typically differ, however, in design from steam turbines used at utility boilers, particularly because of the need for faster startup times and more frequent load cycling. These differences require some unavoidable steam bypass and loss of energy. While some efficiency gains are possible through changes to the low-pressure section of an NGCC steam turbine, any heat rate improvement would be negligible and extremely costly. For these reasons, EPA should focus its efforts around efficiency improvements at coal-fired EGUs.

3. NSR

Finally, in considering how to incorporate heat rate and operating efficiency improvements into any emission guideline for existing EGUs, EPA needs to address potential NSR issues that might arise. PGen believes that heat rate and operating efficiency improvements are not generally the types of actions that trigger NSR. The types of heat rate projects that would reduce GHG emissions at existing EGUs constitute routine maintenance, repair, or replacement, which are excluded from NSR permitting requirements, and/or would not result in a significant increase in emissions.[105] Regardless, EPA and citizen plaintiffs have targeted common component replacement projects, including heat rate improvement projects, for alleged NSR violations.

EPA should consider clarifying in any rule that projects undertaken at existing fossil fuel-fired EGUs to comply with EPA's emission guideline (and the states' subsequent emissions limit) under section 111 do not trigger NSR requirements. In the absence of this type of relief, costs will be increased and delay will occur as source owners will be required to provide analyses demonstrating why certain efficiency improvements do not trigger NSR. This will also place additional burdens on the states that have primary responsibility for establishing and implementing existing source performance standards. And in the situation where a permitting authority (or EPA) believes that an NSR permit is needed, that will add significant cost and time to the project, resulting in a delay in the reduction of GHG emissions and, in some circumstances, the owner or operator abandoning the project because of the increased expense and burden.

PGen recognizes that heat rate and efficiency improvements may not yield significant amounts of emission reduction. This system of emission reduction is proven and commercially available, however, and the setting of emissions limitations under section 111 is not driven by achieving a desired amount of overall emission reduction (unlike the NAAQS program or the Acid Rain Program). Section 111, rather, is a performance and technology-based program. As a result, the Agency or a state cannot require more than is achievable through application of the best system—even if the resulting overall emission reductions are less than EPA or the state might prefer as a matter of policy.

D. Hydrogen

Hydrogen combustion is another promising technology that is not yet ready to be deployed throughout the industry as a system of emission reduction. There are many hurdles that need to be overcome before that can be the case. At this time, the most hydrogen that an NGCC has been able to combust is 44 percent—and most units are much lower than that.[106] There are also significant increases in NOx emissions associated with hydrogen combustion (increases of approximately 24 percent) that offset some of the benefits of reduced CO_2 emissions.[107]

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[105] Letter from Francis X. Lyons, Regional Administrator, EPA, to Henry Nickel, Hunton & Williams at 2, 3 (May 23, 2000), https://www.epa.gov/sites/production/files/2015-07/documents/detedisn.pdf.

[106] Utility Dive, *NYPA burns up to 44% green hydrogen in GE turbine in first such retrofit of a US natural gas plant* (Sept. 23, 2022), https://www.utilitydive.com/news/new-york-power-authority-burns-green-hydrogen-cuts-emissions-EPRI-GE-Airgas-NYPA/632527/.

[107] Clean Energy Group, *Hydrogen Hype in the Air* (Dec. 14, 2020), https://www.cleanegroup.org/hydrogen-hype-in-the-air/ (noting two European studies that have found that combusting "hydrogen-enriched natural gas in an industrial setting can lead to NOx emissions up to ***six times that of methane***" (emphasis in original)).

Some of the issues associated with CCUS are also present with hydrogen combustion. For example, as with CCUS, there needs to be a means to physically store the hydrogen.[108] Hydrogen can be stored in salt caverns, depleted oil and gas reservoirs, aquifers, abandoned mines, or rock caverns, but these features need to be close to the EGU—which is not always possible. While hydrogen can be stored in pressure vessels, this requires proper materials to avoid embrittlement. In addition, like CCUS, water is a significant issue. Producing enough hydrogen for a natural-gas plant requires enormous amounts of water, which is not available in large parts of the country.[109]

These are concerns about the integrity of the fuel supply and whether there can be a consistent source of hydrogen.[110] The vast majority of hydrogen today is made from natural gas and is very carbon-intense,[111] which will not achieve GHG emission reductions. Implementing a hydrogen-based standard makes no sense until there is a strong and reliable supply of green or blue hydrogen, which simply does not exist at this time.

Finally, there are significant safety concerns regarding flame stability that need to be resolved,[112] and it is unclear how compromised the turbine blade materials may become under the higher flame temperature. Embrittlement is also an issue.[113]

X. NSPS for Fossil Fuel-Fired EGUs[114]

EPA first established NSPS to address CO_2 emissions from new, modified, and reconstructed fossil fuel-fired EGUs in October 2015,[115] with those NSPS applying to EGUs that commenced construction after January 8, 2014, or commenced modification or reconstruction

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108 *See, e.g.*, DOE, NETL, *Underground Hydrogen Storage Remains a Key Research Topic for NETL* (Aug. 22, 2022), https://netl.doe.gov/node/11982.

109 D. Pimentel, et al., *Renewable Energy: Current and Potential Issues: Renewable energy technologies could, if developed and implemented, provide nearly 50% of US energy needs; this would require about 17% of US land resources* at 1115, BioScience, Vol. 52, No. 12 (Dec. 2002), https://academic.oup.com/bioscience/article/52/12/1111/223002 (noting "[t]he water required for electrolytic production of 1 billion kWh per year of hydrogen is approximately 300 million liters of water per year," amounting to 3000 liters of water per year on a per capita basis, and noting that "[w]ater for the production of hydrogen may be a problem in arid regions of the United States and the world").

110 Congressional Research Service, *Hydrogen in Electricity's Future* at 11 (June 30, 2020), https://crsreports.congress.gov/product/pdf/R/R46436 (noting high cost of producing hydrogen) ("CRS Hydrogen Report").

111 DOE, Office of Energy Efficiency & Renewable Energy, *Hydrogen Production: Natural Gas Reforming*, https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming ("Today, 95% of the hydrogen produced in the United States is made by natural gas reforming in large central plants").

112 *See, e.g.*, CRS Hydrogen Report at 8 (listing disadvantages of hydrogen, including wide flammability).

113 *Id.* (noting "[h]ydrogen's high flammability means that it burns at a high temperature that makes it unsuitable for use directly in the combustion turbines used to burn natural gas today"); DOE, Office of Energy Efficiency & Renewable Energy, *Safe Use of Hydrogen*, https://www.energy.gov/eere/fuelcells/safe-use-hydrogen.

114 This Section generally responds to Question No. 5 from the Questions for Consideration.

115 80 Fed. Reg. 64,510 (Oct. 23, 2015).

after June 18, 2014.[116] EPA is in the process of reviewing those NSPS to determine whether it is appropriate to revise them.[117]

During this process, EPA should keep in mind the importance of natural gas-fired generation to the stability of the grid during the energy transition. As discussed in Section IV above, reliability has become a bigger issue as more fossil fuel-fired generation retires and more intermittent generation is added to the generation mix. To ensure electric reliability throughout the country, there needs to be sufficient baseload generation and sufficient backup generation for intermittent generation.

There are three types of EGUs that can provide reliable baseload generation: coal-fired EGUs, NGCC units, and nuclear power plants. NGCC units are the best option available to provide flexible, low-carbon baseload generation during the energy transition as intermittent resources make up a greater portion of generation portfolios. These units emit far less CO_2 than coal-fired units (about one-half), are not prohibitively expensive to construct or operate, provide reliable electric generation in significant quantities, and can ramp up or down relatively quickly. While nuclear power plants provide reliable baseload generation and do not have any CO_2 emissions, they are currently cost prohibitive and are subject to lengthy and challenging permitting and siting. The implementation timeline for nuclear generation precludes its use to meet near- to mid-term generation needs related to transitioning from aging coal-fired EGUs. Also, while small modular reactors are promising and may provide an option in the future, they are not yet commercially available. Nuclear generation also has other environmental issues that make it less attractive.

Natural gas-fired simple cycle combustion turbines are a reliable peaking power resource to provide backup to intermittent generation such as wind and solar (that provides less certain electric generation). These units are relatively inexpensive to construct, can provide electric generation on demand, and require very little time to start up. These features have led these EGUs to be used frequently as "peaking" units because they can operate from several hours per day to a few hours a year depending on need. These units can also be constructed relatively quickly. Simple cycle combustion turbines are also more reliable than battery backup. Large-scale battery storage technologies and extended storage duration, while promising, are not yet ready to be deployed throughout the industry.

As EPA reviews the NSPS for NGCC units and simple cycle combustion turbines, it should be mindful of not making the construction of these units too burdensome or expensive as doing so could slow down the energy transition. Power companies, which have legal obligations to provide reliable electricity to their customers, will be unable to retire older, less efficient baseload units (such as coal-fired EGUs) if they cannot construct baseload generation to replace it. Similarly, the inability to easily construct simple cycle combustion turbines to backup solar and wind generation could reduce near-term renewable energy penetration.

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[116] 40 C.F.R. § 60.5508.

[117] *See* CAA § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B) (requiring EPA to review NSPS at least every 8 years).

A. The NSPS for Combustion Turbines

In 2015, EPA appropriately subcategorized combustion turbines into two categories: baseload and non-baseload. PGen recommends that EPA retain this subcategorization as it continues to make sense to do so.

1. Baseload Combustion Turbines

For baseload combustion turbines, EPA determined in 2015 that the BSER is "modern efficient NGCC technology." PGen encourages EPA to retain NGCC technology as the BSER for baseload combustion turbines. That said, this technology has improved since 2015, and the current NSPS of 1,000 lbs of CO_2/MWh for new baseload combustion turbines should be revised.

EPA has been actively studying new technologies for combustion turbines, releasing a draft white paper on potential GHG control technologies for new combustion turbines earlier this year.[118] The paper examined post-combustion CCUS, hydrogen, oxygen combustion, efficiency improvements, and integrated non-emitting generation as potential control technologies.

As discussed above in Section IX.A.5(a) with regard to existing EGUs, CCUS, while promising, has not yet been constructed on any natural gas-fired power plants. While there are some pilot projects being contemplated, none of them have progressed beyond the engineering phase, and the project that is furthest along is at least three years away from any kind of operation. As a result, CCUS for combustion turbines has not yet met the threshold to be considered adequately demonstrated and should not be considered as a system of emission reduction at this time.

Similarly, as discussed in Section IX.D, hydrogen combustion is another encouraging technology that requires further progress and development before it can be considered adequately demonstrated. Oxygen combustion is in its infancy. As EPA notes in its white paper, there are some pilot projects examining the technology's potential. While there are some announced commercial projects that will attempt to use the Allam-Fetvedt cycle, these units are not expected to commence operation until 2025.

With regard to efficiency improvements, combustion turbines are already extremely efficient. While there may be some opportunities for improved efficiency at individual combustion turbine units, those potential improvements are relatively small, they have limited availability, and/or they are unreasonably costly.

PGen is hopeful that technologies—such as CCUS or hydrogen combustion—may make serious breakthroughs in the next few years, especially given the funding that is now available under the IRA. As these technologies make more progress, they may be able to be required through the permitting process as Best Available Control Technology. EPA can also review and

[118] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units (Apr. 21, 2022), https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf.

revise the NSPS as appropriate as the technology develops. The CAA does not require EPA to wait eight years to conduct such a review.

2. Non-Baseload Combustion Turbines

EPA appropriately identified in 2015 that the BSER for non-baseload units is the use of "clean fuels." That determination and its associated achievable rate of 120 lbs CO_2/MMBtu remains appropriate and should not be changed. These non-baseload units are necessary to backup renewable generation and ensure reliability and grid stability. Changing the emissions limitation for these units could make construction of them more difficult, which would inhibit construction of renewable energy generation and would threaten reliability.

Similarly, EPA appropriately identified in 2015 that the BSER for multi-fuel EGUs is the use of clean fuels. The range of emission limitation achievable with this BSER should remain as 120-160 lbs CO_2/MMBtu.

B. The NSPS for Coal-Fired EGUs

There are no plans to construct any new coal-fired EGUs in the United States. There are also not any plans for an existing coal-fired EGU to undergo a major modification. As a result, PGen does not have any recommendations for EPA with regard to these NSPS.

* * *

PGen appreciates EPA's willingness to engage with stakeholders while it is developing proposed rules to address these important issues. PGen recognizes the need to address GHG emissions from fossil fuel-fired EGUs and the importance of addressing climate change. At the same time, EPA should also seek to maintain a reliable and affordable electric system, as compromising either could undermine public support for the clean energy transition.

While the United States undergoes its transition away from fossil fuel-fired electric generation, EPA needs to recognize that many of the new technologies that can potentially limit GHG emissions, while promising, are not yet ready to be deployed on a widespread basis throughout the country. To bridge the gap while technology is developed and while the transition is occurring, PGen recommends that EPA fully embrace flexibility in compliance in the form of emissions averaging and cap-and-trade. PGen asks EPA to follow the approach that it did in CAMR and develop a model trading rule that states can adopt. By allowing flexibility, the goals of reduced GHG emissions can be met while minimizing the impacts on electric reliability and affordability.

PGen is willing to meet with EPA to discuss these comments further, and if EPA would like to do so, it should contact PGen's counsel listed below, who will work with PGen's Board of Directors to arrange a convenient time.

Dated: December 22, 2022

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Final

2021 STATUS OF CARBON CAPTURE UTILIZATION AND SEQUESTRATION FOR APPLICATION TO NATURAL GAS-FIRED COMBINED CYCLE AND COAL-FIRED POWER GENERATION

Technical Discussion paper prepared for

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Executive Summary

Carbon Capture, Utilization, and Storage (CCUS) could play an important role in the decarbonization of the U.S. power sector. It has the potential to accelerate the rate of carbon emission reductions, lessen the impact on customer costs and help maintain energy grid reliability. It also has the promise of increasing production and lowering carbon emissions from U.S. oil production. While much of the near-term carbon reductions are likely to be achieved from the deployment of no- and low-carbon renewable energy, an "only renewables" strategy comes with challenges. Concerns for the rate and cost at which renewable sources can be installed and the impact on the reliability of the energy grid support the continued need for reliable fossil power. While CCUS has run into challenges of its own, many of the operational issues of early projects have been resolved. Lessons learned from initial applications as well as the arrival of new technologies show much promise. The path for CCUS thus far shows many similarities to how the U.S. power sector was able to overcome initial operational and financial challenges for controlling emissions of sulfur dioxide, nitrogen oxides and mercury. Work continues to lower CCUS costs to a target range that makes it economically feasible. Ample sequestration capacity has been identified and work is underway to determine the best ways to develop it cost effectively. It is clear that CCUS could enable fossil power to continue an important role in providing electricity in North America while limiting emissions of carbon dioxide (CO_2).

This paper summarizes CCUS projects representing various stages of technology development and scale underway in North America and identifies further work for CCUS to contribute to a low-carbon energy grid. CCUS initially was focused on coal-fired CO_2 emissions. Over the last decade, other work has pursued potential application to natural gas-fired combined cycle (NGCC) generating assets. Twelve CCUS projects located in North America are either operating, operable but on hold, or the subject of detailed engineering (Front-End Engineering and Design, or FEED) studies. Operating issues encountered by some of the first projects – augmented by research aimed to reduce cost and improve reliability – could potentially lead to full-scale CCUS demonstrations.

Key North American Projects

Four categories of CO_2 capture technology are under development. These are: (1) absorption processes (typically employing an amine solvent), (2) adsorption utilizing a solid substrate, (3) membranes for CO_2 separation, and (4) cryogenic separation. Most large-scale CCUS projects in North America – four addressing NGCC and eight coal-fired generators – employ absorption processes and utilize second-generation solvents that can lower operating and capital cost relative to earlier versions.

Four NGCC projects (Golden Spread's Mustang, Panda Power's Sherman, Elk Hills, and Mississippi Power's Daniel Unit 4) are developing process designs. Three of these projects

(Golden Spread, Panda Power, and Elk Hills) are near CO_2 pipelines or fields that may accommodate geologic sequestration.

Of the eight pulverized coal projects, two are either operating (Boundary Dam 3) or operational and "on-hold" (Petra Nova). Design studies are in progress at five other domestic U.S. generating stations (Minnkota Power Cooperative's Milton R. Young, Basin Electric's Dry Fork, Nebraska Public Power District's Gerald Gentleman, Enchant Energy's San Juan, and Prairie State). The predominant control technology is amine-based absorption, applying "lessons learned" from Boundary Dam Unit 3 and Petra Nova. Most pulverized coal sites benefit by proximity to oil fields or pipeline transport for CO_2 storage.

The U.S. Department of Energy (DOE) is funding approximately 75 evolving processes in the four previously defined categories to achieve a target CO_2 cost of $30 per metric ton (hereafter designated as tonne). The outcome of this program employing bench-scale, pilot plant, and large-scale projects could be additional CCUS options with lower cost and improved reliability.

CCUS Value Chain: Pipelines, Storage

In addition to capturing CO_2 from power plant emissions, successful CCUS requires a complete "value-chain" of activities. The creation of a functioning and economical value chain is equally important to CO_2 capture for CCUS to be a viable option. This includes both pipelines to transport CO_2 and storage facilities.

- Pipelines

  CO_2 pipeline infrastructure at present totals 5,500 miles and is located mostly within U.S. oil-producing states and Canadian provinces. Some stakeholders are estimating the need for pipeline inventory to increase four to more than 10-fold for it to be able to significantly contribute to large reductions in emitted CO_2.

  CO_2 pipelines are regulated by the Department of Transportation (DOT) under the Pipeline Hazardous Material and Safety Administration (PHMSA). CO_2 pipelines operate at significantly higher operating pressure than for natural gas transport – a minimum of 1070 pounds per square inch gauge (or psig) is required for injection for sequestration, with pressure up to 2,200 psig for some applications – than natural gas pipelines. However, experience demonstrates CO_2 pipelines are safe. There has not been a single human fatality or serious injury reported in the U.S. from transporting or storing CO_2. The cost to build CO_2 pipelines is highly variable and depends on length, routing, and need for contaminant removal. A "hub" pipeline arrangement that aggregates CO_2 from multiple sources for distribution to multiple sequestration or EOR sites could lower cost for financing, construction, and permitting.

- Storage

  Enhanced Oil Recovery (EOR*)* is routinely used by the petroleum industry and has proven to be a reliable means to sequester CO_2. The estimated CO_2 storage capacity in

North America using EOR is sufficient to avoid releasing significant CO_2 emissions. The DOE projects 186 billion tonnes to 232 billion tonnes of capacity while the petroleum industry estimates 247 billion tonnes to 479 billion tonnes. CO_2 injection wells for EOR are designed as EPA Class II wells which provide for safe CO_2 injection. Revenue for CO_2 to increase oil production (combined with Internal Revenue Section 45Q tax credits) can offset the cost of CCUS.

Geologic sequestration is estimated to offer far more CO_2 storage capacity than EOR in North America, from 2,618 billion tonnes to 21,987 billion tonnes. Deep saline reservoirs offer the largest capacity and are the most prominent but not the only option. Unlike EOR, there is no revenue to offset cost. DOE estimates storage costs vary from $1/tonne to $18/tonne. Injection must use EPA Class VI wells and address actions beyond well construction and operation.

Cost Evaluation

A key metric to gauge CCUS economic viability is the cost to avoid a tonne of CO_2. Preliminary results for most U.S. coal-fired projects predict cost at or below DOE's reference study cost of $55/tonne and potentially approaching the target of $30/tonne. The latter could be reached by "nth-of-a-kind" full-scale demonstration projects that benefit from design and operating experience. The avoided cost per tonne is sensitive to capital cost, equipment lifetime and capacity factor (e.g., how many hours per year and duty). Internal Revenue Service Section 45Q tax credits – available for either EOR or storage of CO_2 – assert an important role on the incurred cost.

The eleven projects operating and planned will identify process improvements to lower cost and improve reliability. Advanced capture technologies and pipeline "hub" concepts have the potential to further lower cost. Success in these endeavors – requiring resources and a workable development timetable – can enable CCUS to provide reliable CO_2 capture and safe byproduct storage.

1 Summary

1.1 Introduction

Carbon Capture, Utilization, and Storage (CCUS) is receiving considerable interest in proposed plans to decarbonize the U.S. power sector. CCUS has evolved in the last decade as a means to avoid CO_2 emissions from both coal- and natural gas-fired generating assets for both new and retrofit application.

This paper summarizes results from large-scale operation, engineering studies, and pilot plant work supporting CCUS application with electric generating units in North America. Significant work has been completed on applications in the commercial and industrial sector, such as at natural gas processing and ethanol plants. Certain aspects of this work should benefit utility application. However, current work in North America is the focus of this report, given the near-term interest in large-scale application to natural gas fired combined cycle (NGCC) generators and retrofit to coal-fired units.

1.2 Large-Scale Projects

A total of 12 relevant projects in North America are either operating, operable but on hold, or the subject of detailed Front-End Engineering and Design (FEED) studies. Numerous laboratory-scale and pilot plant investigations also are progressing to pursue advanced concepts or aid in "scale-up" activities. Four of the 12 projects address NGCC application while the other eight focus on pulverized coal applications. The CO_2 capture technologies evaluated at large-scale to date – almost all absorption processes using amine-based solvents – are also evaluated for applicability to commercial (e.g., non-utility power generation) applications, such as natural gas processing and ethanol production.

Almost all projects are integrated systems that not only address CO_2 capture but also evaluate CO_2 transport and disposition via either Enhanced Oil Recovery (EOR) or onshore (geologic) sequestration. Some projects have favorable scaling and location advantages. They employ a capture process readily scaled from a pilot plant or large-scale process, and are located adjacent to an existing CO_2 pipeline, oil field, or a deep saline formation. Other projects address more risk in terms of scale-up and geologic storage of CO_2.

1.2.1 Natural Gas/Combined Cycle Application

The four NGCC projects that employ CO_2 capture by absorption[1] with amine solvents were scheduled to report detailed engineering to DOE by late 2021.

- The Panda Sherman study evaluates a process employing a generic mono-ethanolamine (MEA) solvent applicable to a 740.6 MW (gross) Siemens "Flex Plant" generator. The disposition of CO_2 by either EOR or sequestration in an adjacent saline formation is possible with minimal pipeline construction.
- The Golden Spread Mustang station 430 MW (gross) unit with GE turbines will test a second-generation solvent (piperazine). It is being developed jointly by Honeywell and the University of Texas at Austin. This solvent – combined with the "flash-stripping" process improvement – is intended to reduce auxiliary energy demand and lower capital cost.
- The Mississippi Power Plant Daniel Unit 4 is a 525 MW (gross) unit that also will test a second–generation reagent. The reagent developed by Linde-BASF will be evaluated in concert with improved process design.
- The Elk Hills project builds upon prior work, advancing Fluor's Econamine process by employing a second-generation solvent and refined process design. Notably, Elk Hills is distinguished by location. It is located within the existing Elk Hills oil field, with CO_2 use for EOR requiring construction of minimal pipeline infrastructure. A report prepared for the California Energy Commission cited Elk Hills as "…one of the most suitable locations for the extraction of hydrocarbons and the sequestration of CO_2 in North America."[2]

For most of these projects, estimates of capital cost, operating cost, and the cost to avoid a tonne of CO_2 were to be reported to the DOE by the end of 2021. The sole publicly available costs for CCUS application to NGCC available currently are from a 2019 study conducted by DOE's National Energy Technology Laboratory (DOE/NETL) addressing a hypothetical 646 MW (net) unit.[3] This DOE/NETL study reports the cost to include the 2017-vintage solvent (the Shell Cansolv, hereafter referred to as Cansolv) process in a "greenfield" NGCC units with GE 7FA gas turbines. These cost results are discussed with those for coal-fired duty subsequently in this summary section.

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[1] As subsequently addressed, absorption is the uptake of CO_2 into the bulk phase of another material. Absorption processes are featured in the present test plans, but alternative categories are anticipated to be equally competitive.

[2] Appendix F, URS Report on CO_2 Sequestration for California Energy Commission. 2010

[3] Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity, NETL-PUB-22638, September 24, 2019. Hereafter DOE/NETL 2019 Cost and Performance study. This analysis is presently being updated with results scheduled for a 3Q 2021 release.

1.2.2 Coal-Fired Application

Parallel work is underway to demonstrate CCUS for coal-fired duty, mostly exploring absorption processes. One alternative process (membrane) is being evaluated at one large-scale project, with additional alternatives explored at pilot scale.

Eight coal-fired projects are either operating, operable but on hold, or the subject of detailed FEED studies.

One project is operating while operations at a second plant have been suspended:

- SaskPower's 111 MW (net) Boundary Dam Unit 3 test of the Shell CanSolv process has operated since 2014. This "first-of-a-kind" application identified and resolved many operating issues during its first three years. Boundary Dam Unit 3 continues to operate. The CO_2 is transported approximately 45 miles for EOR or to a nearby site for geologic sequestration.
- NRG Petra Nova's 240 MW (net) test of the Mitsubishi Heavy Industries (MHI) Advanced Kansai Mitsubishi Carbon Recovery Process (KM-CDR) was suspended in 2020. The unit resolved numerous operating challenges (most with the cogeneration facility) during the first three years and transported CO_2 to the West Ranch oil field for EOR. However, the 2020 uncertainty in oil markets prompted Petra Nova owners to suspend operation due to unfavorable return on EOR investment.[4] Future operating plans are not publicly available.

The other six sites are conducting FEED or equivalent engineering studies. Five are evaluating absorption processes that are like those evaluated for NGCC units and the sixth is evaluating a membrane separation process:

- Minnkota Power Cooperative's 477 MW (gross) lignite-fired Milton R. Young Station. It is evaluating retrofit of the Fluor Econoamine FG process (also slated for large-scale testing at Elk Hills) for coal-fired duty. CO_2 captured will be directed to a saline reservoir essentially below the station footprint.
- Enchant Energy's San Juan Generating Station Units 1 and 4 (914 MW gross). The project is refining the MHI KM-CDR design of the absorption process used at Petra Nova. CO_2 captured will either be sequestered in the San Juan Basin formation (being characterized in partnership with New Mexico Institute of Mining and Technology as part of the DOE CarbonSAFE Phase III program), utilized for EOR in nearby oil fields, or transported via a 20-mile pipeline to Kinder Morgan's Cortez pipeline for EOR in the Permian Basis.
- Prairie State Generating Station 816 MW (gross) Unit 2 is evaluating a third application of the MHI KM-CDR process. CO_2 sequestration in Illinois is the subject of a companion study.[5]

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[4] See: https://www.energyandpolicy.org/petra-nova/.

[5] Whittaker, S., *Illinois Storage Corridor*, DOE NETL Carbon Capture Front End Engineering Design Studies and Carbon Safe 2020 Integrated Review Webinar, August 17-19, 2020.

- Public Power District's Gerald Gentleman Station's 300 MW (net) module in Nebraska will evaluate an absorption solvent developed by Ion Clean Energy at pilot-scale. Byproduct CO_2 from the Gerald Gentleman Station will be used for EOR at a nearby location.
- Basin Electric Dry Fork 385 MW (net) station is evaluating MTR's Polaris membrane[6] technology through a FEED study.
- SaskPower completed a FEED study exploring application of the KM CDR process at the Shand Station, utilizing CO_2 for EOR at both the Weyburn and Midale fields that are utilized by the Boundary Dam 3 project.

The available cost information and the effect of externalities such as Section 45Q tax credits are addressed subsequently.

1.3 Evolving Technologies

There are numerous technologies for CO_2 capture. In addition to absorption and membrane processes introduced, adsorption and cryogenic processes also could offer attractive features.

As noted, MTR's Polaris membrane option presents a viable alternative. The demand for heat energy to liberate CO_2 by absorption processes can be used to generate auxiliary power to overcome the membrane pressure resistance. Advanced membrane designs can improve performance in maintaining CO_2 removal effectiveness with lower gas pressure drop. Other than MTR membrane technology is being developed by Air Liquide, the Gas Technology Institute (GTI), and in academia (the Ohio State University and the University at Buffalo, for example).

Adsorption (as opposed to absorption) and cryogenic processes also are being researched on several pilot plants. Any one of these options could provide a competitive post-combustion process for either NGCC or coal-fired duty.

The Allam-Fetvedt cycle being developed by Net Power for natural gas or renewable gas is a long-term concept that also offers potential to provide cost-effective fossil fuel power with integrated CO_2 capture. This concept, which has been described as a specialized Brayton cycle, employs high-temperature, high-pressure CO_2 as the working medium for expansion in a turbine. The process fires oxygen with natural gas, eliminating nitrogen and the need for CO_2 post-combustion separation. There are technical challenges with this concept, including those related to exotic materials-of-construction as required to survive the high temperature and pressure that provide high inherent thermal efficiency. Claimed efficiency is approximately 40 percent for coal-fired application[7] and approaching 60 percent for natural gas fired application.[8] Significant

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[6] Membranes employ inherent differences in molecular permeation rates through porous material to separate compounds with difference molecular weights.

[7] Goff, A. et. al., Allam Cycle Zero Emission of Coal Power, Pre-FEED Final Report. Available at: https://netl.doe.gov/coal/tpg/coalfirst/DirectSupercriticalCO2.

[8] See: https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.

private capital is being directed to developing this concept in addition to DOE funds. Two units cumulatively totaling 560 MW are slated for test operation by 2025.[9]

1.4 CO_2 Pipeline Infrastructure

U.S. pipelines have transported CO_2 since 1972, almost exclusively for EOR. The inaugural CO_2 pipeline service was in West Texas. There are approximately 5,500 miles of CO_2 pipelines presently in operation, with estimates of capacity to serve future CCUS needs ranging from a four-fold[10] to more than ten-fold[11] increase.

The major regions in the U.S. that host CO_2 pipelines typically are oil-producing basins of the Northern Rockies, Permian Basin, Mid-Continent, and the Gulf Coast.

In addition to CO_2 pipelines, the U.S. has even greater experience with successfully operating large pipelines for gaseous and liquids material transport. There are more than 535,000 miles of pipelines for transporting natural gas and hazardous liquids. While there are many similarities between pipelines carrying CO_2 and other materials, the biggest difference is operating pressure. CO_2 pipelines typically operate at higher pressures than natural gas and hazardous liquids pipelines. At a minimum, CO_2 pipeline pressure must be elevated to 1,070 pounds per square inch gauge (psig) for CO_2 to penetrate 1 kilometer (km) below the surface, the depth needed for effective sequestration. The minimum pressure transforms CO_2 into a supercritical fluid, exhibiting the characteristics of both a gas and liquid. Some CO_2 pipelines operate at pressures up to 2,200 psig,[12] requiring a secure pipeline structure including thicker walls.

The cost for CO_2 pipelines varies depending on a number of factors, including the pipeline diameter size, required operating pressure, site location, and length. The key metric is cost per inch-mile, where "inch" refers to the diameter of the pipeline and "mile" to the length of the pipeline in miles**.** Another key cost variable is determined by land ownership and the required compensation for right-of-way. Typically, the least- cost-per-mile pipelines are built in rural areas, transgress land of low-to-modest economic value, and are of extensive length to derive economies of scale. In contrast, the highest-cost-per-mile pipelines typically are relatively short and are built in commercial or residential areas with intermediate to high population density. For

[9] 8 Rivers Unveils 560 MW of Allam Cycle Gas-Fired Projects for Colorado, Illinois, Power Magazine, April 15, 2021. Available at: https://www.powermag.com/8-rivers-unveils-560-mw-of-allam-cycle-gas-fired-projects-for-colorado-illinois/.

[10] U.S. Department of Energy, National Energy Technology Laboratory. (2015). *A Review of the CO_2 Pipeline Infrastructure in the U.S.*, DOE/NETL-2014/1681. Hereafter DOE/NETL 2015 Pipeline Infrastructure Study.

[11] Net –Zero America: Potential Pathways, Infrastructure, and Impacts. Available at: https://environmenthalfcentury.princeton.edu/research/2020/big-affordable-effort-needed-america-reach-net-zero-emissions-2050-princeton-study. Hereafter Princeton Net-Zero America study. Graphic 219.

[12] Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, 2019, National Petroleum Council. Available at: https://dualchallenge.npc.org/. Hereafter NPC 2019 Report. See Chapter 6, Table 6-1.

example, of six recently completed pipelines the cost per inch-mile varied by a factor of 2 ½. The 12.5-mile Seminole pipeline incurred a cost of $80,000 per inch-mile (or $0.48 M per mile), while the 9.1-mile Webster pipeline required almost $200,000 per inch-mile (or $3.2 M per mile).[13]

Byproduct CO_2 must be cleaned of contaminants that prompt corrosion or change fluid properties in a manner to increase pumping costs. All pipeline operators have standards defining CO_2 purity, limiting content of water, hydrogen sulfide, oxygen, and miscellaneous hydrocarbons such as glycol. Because of their high operating pressure, CO_2 pipelines are regulated by the Department of Transportation (DOT) under the Pipeline Hazardous Material and Safety Administration (PHMSA).

Finally, the concept of pipeline "hubs" – where geographically clustered CO_2 sources share pipelines with storage or EOR sites – is receiving interest. In contrast to "point-to-point" transport, hubs aggregate CO_2 from various sources to exploit economies of scale, reducing cost and complexity. One working example in North America is the Alberta Carbon Trunk Line. In the U.S., three hubs have been proposed. They are:

- The 1,200-mile Navigator Ventures hub, which is proposed to operate through several Midwestern states;
- The Summit Carbon hub, which is proposed to aggregate CO_2 from Midwestern ethanol plants; and
- A hub proposed by Exxon Mobil to aggregate CO_2 from facilities in the Houston Ship channel.

Such hubs are equally applicable to both EOR and saline reservoir sequestration applications.

1.5 Enhanced Oil Recovery (EOR)

EOR – defined as the injection of CO_2 at supercritical conditions within reservoirs to displace oil – is broadly practiced in North America. Six of the twelve CCUS projects cite EOR as the primary CO_2 fate. That EOR fields can safely retain CO_2 is not in question. Natural gas and oil have been entrapped in such formations for millions of years. Further, EOR provides the collateral benefit of lowering life-cycle emission of CO_2 for oil extraction by 40 percent to 63 percent.[14] The CO_2 storage capability alone is sufficient to accommodate numerous CCUS application. Estimates by DOE/NETL range from 186 billion tonnes to 232 billion tonnes.[15]

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[13] Ibid.

[14] International Energy Agency, "Storing CO_2 through Enhanced Oil Recovery, combining EOR with CO_2 storage (EOR+) for profit," 2015. Hereafter IEA 2015 CO_2 EOR and Storage. Available at: https://webstore.iea.org/insights-series-2015-storing-CO_2-through-enhanced-oil-recovery.

[15] NETL Carbon Storage Atlas; Fifth Edition, DOE Office of Fossil Energy, August 2015. Hereafter 2015 DOE/NETL Storage Atlas. Available at: https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.

EOR presents both advantages and disadvantages compared with saline reservoir sequestration. On the plus side, the cost and access to deploy EOR can be less challenging for the source than to sequester CO_2 in a new saline reservoir assuming the existing oil field is already well characterized. Further, EOR injection well design is required to abide by EPA's Underground Injection Control (UIC) Class II well designation requirements, which are less complex than Class VI designs required for geologic sequestration. On the minus side, EOR "sinks" for CO_2 are not uniformly distributed throughout the U.S. They are concentrated in oil-producing regions (e.g., the Permian Basis in Texas). Also, each field features unique geologic characteristics, and some may not be amenable to EOR. And, if Section 45Q tax credits (discussed in Section 9) are used, meeting the requirement to certify CO_2 sequestration could be challenging for some oil field operators.

There are more than 150 EOR sites in operation internationally,[16] with potential opportunities within the Permian Basin described by DOE as "too numerous to count".[17] Prominent examples include the Denver Unit in the West Texas Permian Basis, Bell Creek Field in the Powder River Basin of Montana, and the Northern Niagara Pinnacle Reef Trend in the Michigan Basin.

Historically, EOR fields are designed and operated to *maximize oil produced* with the amount of CO_2 contained incidental to operation. EOR strategy could evolve to maximize CO_2 sequestered while still prompting a significant increase in oil production. The International Energy Agency (IEA) has termed such a strategy as *Maximum EOR* and estimates this approach can contain 0.9 tonnes of CO_2 per barrel while increasing oil production by 13 percent.[18]

As previously discussed for pipelines, EOR economics are enhanced with hub transport, aggregating CO_2 from several sources for use within a region. The previously cited ExxonMobil hub to aggregate CO_2 from the Houston Ship channel is one such example.

Seven CCUS projects plan to or already employ EOR, such as the Weyburn and Midale oil field in Saskatchewan that utilizes CO_2 from Boundary Dam Unit 3. As previously noted, the West Ranch oil field was the primary repository for CO_2 captured from Petra Nova during operation until 2020. Elk Hills in Kern County, CA, plans to deploy EOR from the NGCC unit within the oil field "footprint" to extend oil production at an 111-year-old field. Other examples include San Juan Generating Station Units 1 and 4, for which the 70 EOR applications in the Permian Basin are a primary disposition of CO_2.

EOR cost can be partially deferred by externalities such as the Section 45Q program.

1.6 Sequestration

Geologic storage or sequestration of CO_2 is defined as the high-pressure injection into underground rock formations that – due to their inherent geologic properties – trap CO_2 and

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[16] National Petroleum Council 2019 Report. See Chapter 8, Page 4.
[17] Balch, R., CUSP: The Carbon Utilization and Storage Partnership of the Western U.S., NETL Workshop on Representing Carbon Capture and Utilization, October 2018.
[18] IEA 2015 CO_2 EOR and Storage.

prevent migration to the surface. The estimated capacity of CO_2 storage via sequestration varies widely and exceeds that for EOR, from a low of 2,618 billion tonnes to a high of 21,978 billion tonnes of CO_2.[19]

Sequestration presents both advantages and disadvantages compared with EOR. On the plus side, the geologic "sinks" for CO_2 are distributed across the U.S. In addition to saline reservoirs, potential sinks include unmineable coal seams and depleted natural gas and oil reservoirs. On the minus side, initiating a sequestration field requires detailed characterization of the site, modeling of the CO_2 plume, and rigorous analysis of injection well design. These and other requirements are established by EPA's Class VI UIC regulations to protect underground sources of drinking water and can limit the CO_2 volume stored.

The optimal sequestration site will exhibit high porosity and interconnected pathways to disperse CO_2, a feature offered by 75 percent of formations. Most common are subsurface rock formations with pores filled with saline and featuring caprock or otherwise impermeable seals that prevent CO_2 migration to the surface. The ideal formation also features alternating layers of low and high permeability rock. That allows the high-pressure saline and injected CO_2 to expand while still being contained under the impermeable caprock layers.

Several organizations have estimated sequestration cost, considering various attributes of the site, the design of injection wells, and mass of CO_2 injected.[20] NETL developed a model that for conditions relevant to U.S. application suggests the cost for sequestration using a saline reservoir (exclusive of pipeline capital and operating costs) ranges from $8/tonne to $13/tonne (2013 basis).[21] In 2019, preliminary cost estimates were as low as $3/tonne of CO_2 for storage sites in the southeastern U.S. that feature excellent geologic conditions.[22] Storage cost is primarily affected by the depth of the formation, volume of CO_2 to be stored, number of injection wells required, purity of the CO_2 stream, existing land uses, and ease of deploying surface and subsurface CO_2 monitoring programs.

CO_2 has been successfully sequestered internationally since the mid-1990s. For example, the earliest efforts in Norway (the Sleipner and Snohvit projects) complemented by additional work provides a basis for North American activities. In Canada, notable projects in North America are Aquistore and Quest. In the U.S., projects in Illinois (Decatur) and at Alabama Power's Barry Station (Citronelle) are being evaluated or are complete.

Perhaps the most important near-term sequestration studies are companion projects to the CO_2 capture projects. Enchant Energy's plans are to direct CO_2 from San Juan Units 1 and 4 to the nearby San Juan Basin for saline storage or EOR. In Mississippi, Kemper County is being evaluated as a site for CO_2 disposition for three potential CCUS projects: two NGCC units at

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[19] DOE/NETL 2015 Storage Atlas.

[20] *FE/NETL CO_2 Saline Storage Cost Model: Model Description and Baseline Results*, July 18, 2014. DOE/NETL-2014/1659

[21] Rubin 2015. See Table 13

[22] Esposito, R.A., Kuuskraa, V.A., Rossman, C.G., and Corser, M.C. 2019. Reconsidering CCS in the U.S. fossil-fuel fired electricity industry under section 45Q tax credits. *Greenhouse Gas Science & Technology*, 0:1–14 (2019); DOI: 10.1002/ghg.1925

Plant Ratcliffe and Plant Daniel and a third at coal-fired Plant Miller. The permit application and Class VI well injector designs are complete for this site. Also notable is the Wyoming CarbonSAFE Storage Complex, which is planned to offer both EOR and sequestration in Campbell County, WY, for CO_2 disposition from the Dry Fork Station. Project Tundra will likewise use favorable geology at the capture site to sequester CO_2 5,000 feet below the project sites near Center, North Dakota, for use at the Milton R. Young Generating Station project.

Finally, the "hub" pipeline strategy is being explored to extract economies of scale by developing regional CO_2 sequestration sites. Several states – most notably Illinois with the Illinois Storage Corridor – are completing in advance of CO_2 capture projects the environmental analyses and permits for pipeline construction. By completing the requisite background work, these efforts will enable rapidly initiating construction. Other notable efforts are the Integrated Midcontinent Stacked Carbon Storage (Kansas, Nebraska) and the Carbon Utilization and Storage Partnership. The latter is considering plans to aggregate CO_2 from sites in 13 different states. Challenges remain to implement the hub concept, but the benefits can be significant.

In summary, adequate CO_2 storage exists to support CCUS application in North America. On-going work aims to define the means to develop sites.

1.7 Cost Evaluation

Any discussion of CCUS cost starts with identifying the relevant metric(s). The most widely used cost metric is that to avoid a metric ton (tonne) of CO_2. This is determined by aggregating all direct and indirect costs of CO_2 capture and storage normalized by the net CO_2 avoided.[23] This widely cited metric is the basis for cost reimbursement schemes such as Section 45Q credits. However, the cost to avoid a tonne of CO_2 is influenced by numerous factors, such as unit capacity factor and capital requirement. Consequently, this metric – without presentation of capital requirement, facility lifetime, and capacity factor – provides an incomplete cost description.

Figure 1-1 presents reported capital cost ($/kW) and avoided cost per tonne ($/tonne) for the large-scale projects and studies. The results are presented in order of increasing net generating capacity, thus accounting for auxiliary power consumed by CCUS. Two additional variables that affect cost are reported, including the planned lifetime of the facility (which determines annual capital recovery cost) and the operating capacity factor.

The CO_2 removal (percent basis) is not reported but is 90 percent for all units except at the Dry Fork Station. Unless noted, costs in Figure 1-1 represent CO_2 produced at the fence line and does not consider transportation and storage, or any credits for tax treatment.

[23] For example, in regard to CCUS, CO_2 emissions generated by the power (MWh) consumed by CO_2 capture and storage equipment are not accounted for in the CO_2 removed, while cost associated with removal are.

1.7.1 NGCC

The four NGCC projects described in Section 3 – Golden Spread, Panda Sherman, Elk Hills, and the Daniel Unit 4 – were scheduled to deliver revised cost estimates to the DOE in late 2021. The sole NGCC cost presently available is the DOE/NETL 2018 study presently undergoing update.[24] Figure 1-1 shows the 2017-vintage Cansolv process requires $1,600/kW for a site comprised of two F-Class gas turbines and HRSGs configured in a 2 x 2 x 1 arrangement and avoids CO_2 for $80/tonne based on an 85 percent capacity factor and 30-year plant lifetime.

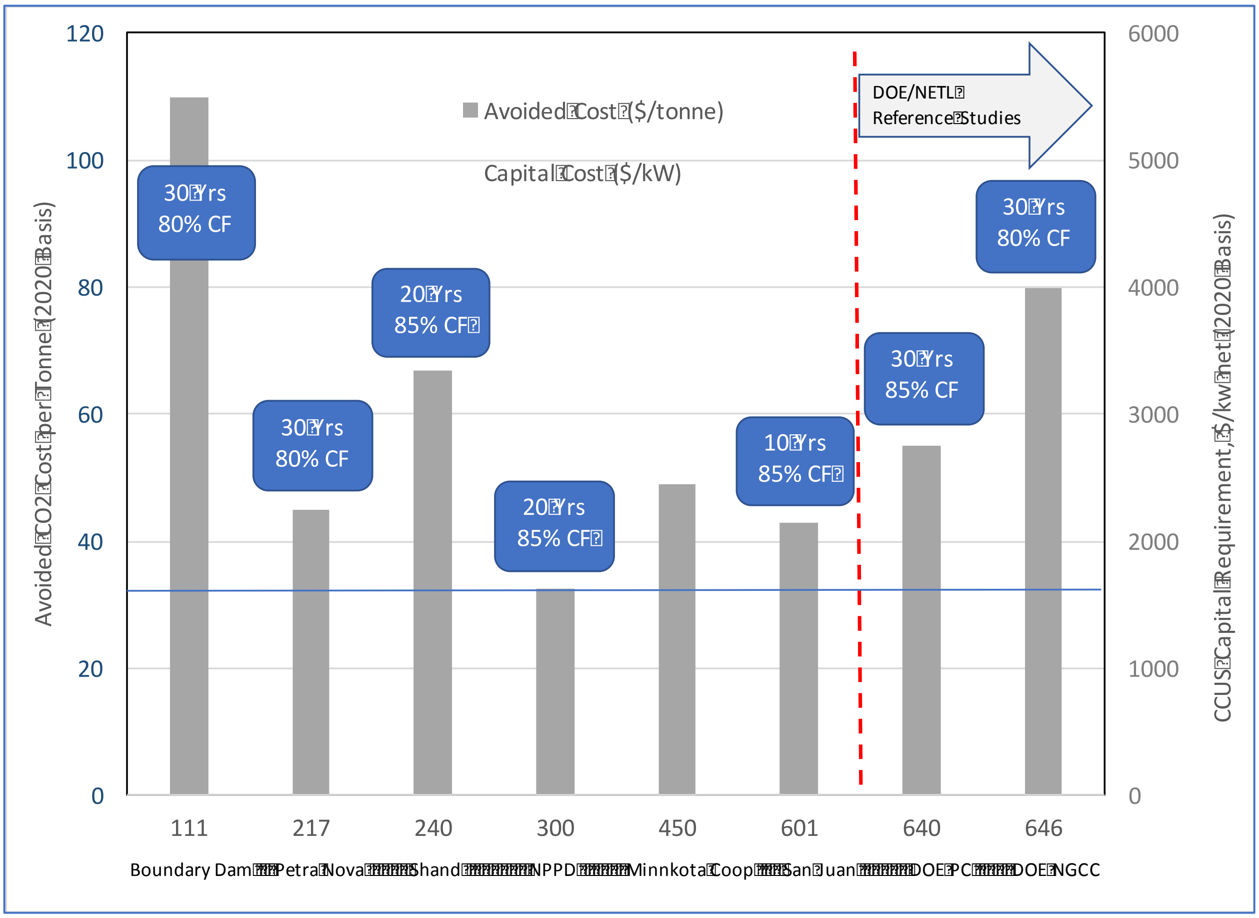

Figure 1-1. Capital Cost, Avoided CO_2 Cost per Facility Lifetime, Capacity Factor

1.7.2 Pulverized Coal

Figure 1-1 reports SaskPower Boundary Dam Unit 3 incurred the highest capital requirement of $5,405/kW and cost per tonne of CO_2 avoided ($110), a consequence of first-of-a-kind application and small capacity (111 MW net). NRG Petra Nova represents a 60 percent reduction in capital ($2,500/kW) for a similar absorption process, initiating three years after Boundary Dam (2016) and applied to twice the generating capacity. The implied cost to avoid a tonne of CO_2 of $67/tonne represents about a one-third reduction from Boundary Dam Unit 3. The SaskPower Shand proposed CCUS design projects 65 percent lower capital requirement

[24] DOE/NETL 2019 Cost and Performance Study.

($2,121/kW) and similarly lower avoided CO_2 cost compared with Boundary Dam Unit 3. The avoided CO_2 cost at Shand of $45/tonne is calculated for a 30-year facility lifetime and 85 percent capacity factor.

Subsequent projects are not based on extensive experience and cost could be uncertain. The NPPD/Gerald Gentleman cost of $1,420/kW and $32.50/tonne to avoid CO_2 is preliminary – cited as a "Class 3" AACE cost estimate.[25] A capital recovery period of 20 years is employed in the analysis and an 85 percent capacity factor. A more detailed FEED study developed to a "Class 2" AACE basis will be available in late 2021. The process design for this unit is based on a 12 MW net pilot plant, introducing risk in terms of scaling operations and cost.

The Minnkota Power Cooperative Milton R. Young project will extend experience with the Fluor Econamine process, as derived from the 10 MW Wilhelmshaven pilot plant.[26] The scale-up to this 450 MW net site will also benefit from experience from the Petra Nova 240 MW large-scale test. Although Petra Nova employed a different CO_2 solvent, numerous scale-up lessons can be applied to this project. A preliminary capital cost has not been released, although an avoided cost estimate of $49/tonne is predicted.

A FEED study addressing the Enchant Energy San Juan Generating Station will be completed by the end of 2021. This study will utilize the version of the MHI KM-CDR solvent that was tested and refined with Petra Nova experience. A predecessor cost study for application of a general amine-based system at this site estimated capital cost of $2,150/kW. The cost to avoid CO_2 was $42/tonne based on an 85 percent capacity factor and an implied lifetime of 10 years.[27]

NETL's most recently published evaluation (2019) estimated CCUS capital for a 2017-vintage Cansolv process of $2,454/kW and $55/tonne to avoid CO_2, based on an 85 percent CF and 30-year plant lifetime for a 650 MW net.[28] Opportunities to lower this cost are sought through process refinements, advanced solvents, and alternative capture processes.

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[25] The Association for the Advancement of Cost Engineering (AACE) International defines five classes of cost estimate accuracy. A Class 3 estimate addresses projects developed to a maturity level (e.g., percentage of complete definition) of 30-40 percent, and with 80 percent confidence projects cost over a range of 50 percent (-20 percent low to + 30 percent high). A Class 2 estimate addresses projects developed to a maturity level of 30 percent to 75 percent, with an 80 percent confidence to project costs to within 25 percent (-15 percent to +15 percent). Available at: https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf.

[26] Reddy, S. et. al., Fluor's Econamine FG PlusSM completes test program at Uniper's Wilhelmshaven coal power plant, Energy Procedia 114 (2017) 5816-5825.

[27] Enchant Energy San Juan Generating Station – Units 1 & 4: CO_2 Capture Pre-Feasibility Study, Final Report, Sargent & Lundy, Project No. 13891-001, July 8, 2019. Although process lifetime is not described, the reported capital recovery factor of 0.1243 with a 4 percent interest rate implies a 10-year lifetime.

[28] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, NETL-PUB-22638, September 24, 2019. Hereafter NETL Bituminous and NGCC 2019 Reference Study.

1.8 Financial Incentives

A description of potential CCUS credits and impact on cost are relevant to this discussion.

1.8.1 Description of Credits

Several means are available to partially defray CCUS costs. The Elk Hills project defrays cost through three mechanisms: Section 45Q tax credits, the California Low Carbon Fuel Credit (LCFC), and the California Cap-and-Trade program.

Section 45Q tax incentives are intended for power stations and industrial facilities based on the performance of CCUS equipment. Tax credits are awarded to the owner of the power station or qualifying CCUS process but can be transferred to parties involved in related project actions. To qualify, construction must initiate prior to January 1, 2026, and the credit can be claimed for up to 12 years.[29]

Section 45Q tax credits start at $28/tonne for geologic sequestration and $17/tonne for EOR in the initial year of 2018. These credits increase to $50/tonne and $35/tonne respectively in 2026 with the value beyond that period adjusted for inflation. Several changes are required to assure broad support of CCUS, such as extending the qualifying threshold for construction through 2035 and that credits can be claimed for 20 years.[30]

Tax credits are potentially available from a separate provision, Section 48A. These credits were initially intended for integrated gasification/combined cycle projects. One observer opines that qualifying criteria must be revised before CCUS-equipped units can access these funds.[31] The Section 48A tax credit could provide a 400 MW generating unit up to $130 million (undiscounted) for installing CO_2 capture. For a regulated electric company, subject to traditional cost-of-service accounting and recognizing the benefits over the life of the asset, the present value (over 30 years) is $57 million. That is complementary to the 45Q incentives.[32] However, because the credit is not transferable nor available as a direct payment tax credit, it provides no incentive to owners with little to no tax liability.

Some projects may be able to access the California Low Carbon Fuel Standard (LCFS) credit . The LCFS is intended to reduce the carbon intensity of transportation fuels used in California, structured to achieve a reduction of 20 percent by 2030 from a 2010 baseline. The California Air

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[29] Esposito, R.A., Electrical Utility Perspectives on CO_2 Geologic Storage and 45Q Tax Credits, A&WMA Mega Virtual Symposium, November 17-18, 2020. Esposito 2020.

[30] See: https://www.carbonfreetech.org/Documents/CFTI%20Carbon%20Capture%20--%20Summary%20Paper.pdf.

[31] *Building to Net Zero: A U.S. Policy Blueprint for Gigatons–Scale CO_2 Transport and Storage Infrastructure*, prepared by the Energy Futures Initiative, June 30, 2021. Available at: https://energyfuturesinitiative.org/efi-reports. See page 53.

[32] Esposito, R. et. al., Improving the Business Case for CCS in the Electric Generation Industry, 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15
15th 18th March 2021 Abu Dhabi, UAE. Hereafter Esposito 2021.

Resources Board (CARB) has established protocols for calculating the LCFS credits based on the performance of the CCUS project, and the carbon intensity of the fuel being processed or refined. The carbon metric of merit is the well-to-wheel grams of CO_2 equivalent (CO_2e) per megajoule of energy expended (as gigajoules, MJ) and calculated per CARB-designated methodologies.[33] These carbon intensity credits – after surrendering 8 percent to 16.4 percent to establish a "buffer" – can be sold in the LCFS market.

California-based projects such as Elk Hills also can sell CO_2 credits into the California Cap-and-Trade program to augment revenue from LCFS and Section 45Q CO_2 credits. This program assigns "CO_2 equivalent" credits to 80 percent of sources in California, and each year lowers the allocation while increasing the market floor price to prompt a steady market.

1.8.2 Impact on Cost

The availability of Section 45Q tax credits can significantly reduce the ultimate cost incurred for CCUS. However, the structure of support – a credit awarded only after CO_2 capture, transport, and storage facilities are operating and CO_2 storage documented – requires the owner first to raise the necessary capital. For NGCC, an example greenfield 400 MW gross (~330 MW net) generating unit would require a capital cost of approximately $500 M to $510 M ($1,550/kW) for CCUS, exclusive of transport and sequestration costs.[34] An average annual value of Section 45Q credits of $40M translates into a net present value of $340 M, offsetting 66 percent of the $510 M capital charge required. This offset can be increased to 90 percent of the required capital ($460 M of $510 M) by extending the credits for an additional eight years.

For pulverized coal, an example retrofit 400 MW (~330 MW net) generating unit would require a capital cost of approximately $1.2 B to $1.3 B ($2,500/kW) in capital, exclusive of transport and sequestration costs. An average annual value of Section 45Q credits of $130 M translates into a net present value of $1.1 B, offsetting 85 percent of the $1.3 B capital charge. This offset can be increased to 100 percent of the required capital by utilizing the same Section 45Q structure by extending credits for an additional six years.

The value of the offsets will vary with each unit, site, and operating conditions. Among the variables are capacity factor, operating lifetime, and CO_2 capture. The impact on cost to avoid a tonne of CO_2 also depends on the financing and tax liability characteristic of each site.

1.9 Conclusions

Collectively, the nine planned large-scale projects – four addressing NGCC and five coal-firing – will provide valuable experience in CCUS. These research activities and large pilot plant investigations such as that planned at Dallman will improve CCUS reliability and identify lower capital and operating cost.

[33] The well-to-wheel reduction in carbon intensity is calculated per the CA-GREET and GTAP models.
[34] Esposito 2020.

Capital and operating cost estimates presently available are limited, but nine detailed (FEED) studies were to be completed by the end of 2021.

That the bulk of these projects address CO_2 absorption with amine-derived solvents is not an endorsement of that category to the exclusion of others. Rather, this observation reflects several factors, including the suitability of absorption processes to CO_2 concentration typical of combustion products and electric power industry experience with absorber towers. These projects pursue an orderly development. For example, the Enchant Energy San Juan and Prairie State projects will build upon the refinement to the MHI second-generation KM CDR solvent while Elk Hills will leverage prior NGCC experience with the Fluor Econamine process. The test at the Minnkota Power Cooperative Milton R. Young Station will further extend Econamine experience to large-scale coal-firing.

Alternatives to absorption-based processes (membranes, adsorption, and cryogenic capture categories) could provide processes at lower cost. Additional research and large-scale testing are necessary to evolve these technologies.

Transport of CO_2 via pipeline can be accommodated, but it will require a major expansion of capacity requiring a significant financial investment. The cost for transport can be reduced by evolving to a common-carrier or "hub" concept, enabling several sources and CO_2 sinks to share common cost. EOR and saline reservoir sequestration offer means for disposition of CO_2, although each faces challenges. The most-significant challenges may be non-technical, concerning access, right-of-way, and public perception of the importance for terrestrial sequestration.

The present CCUS projects can be considered analogous to early flue gas desulfurization (FGD) installations from which evolved 21st century state-of-the-art designs. Numerous early wet FGD installations encountered performance and reliability issues but served as the basis for process improvement. Examples include Commonwealth Edison 175 MW Will County Unit 1 (1972), Kansas City Power and Light 820 MW La Cygne (1972), Arizona Public Service Cholla 115 MW Unit 1 (1973), and Southern California Edison 170 MW Mohave Unit 1 (1974).[35] These processes employed first-of-a-kind concepts that long-since have been abandoned, such as turbulent contactors with "ping pong balls" and packed towers with plastic "eggcrate" packing to improve mass transfer. These early installations were challenged to achieve 90 percent SO_2 removal and operated with less than acceptable reliability. However, research at the Tennessee Valley Authority's (TVA's) Shawnee Test Facility and the Electric Power Research Institute's (EPRI's) Arapahoe Test Facility and High Sulfur Test Center addressed these issues. The single, open spray tower for wet FGD evolved from this experience. The design evolution continued into the 21st century. By 2005, Babcock Power noted that a single spray tower would be adequate to process 800 MW to 1000 MW of generation, down from three absorption towers needed

[35] A History of Flue Gas Desulfurization Systems Since 1850, Journal of the Air Pollution Control Association, 27:10, 948-961, DOI: 10.1080/00022470.1977.10470518 Available at: https://doi.org/10.1080/00022470.1977.10470518.

previously.[36] Similar evolutions in FGD included dual alkali and semi-dry processes that provided alternatives and maintained competitive pressure on conventional wet FGD.

This same path of innovation and scale-up – with adequate resources for research and an amenable timetable for development – has potential to deliver cost reductions and improvement to reliability for CO_2 capture and safe disposition of byproduct.

[36] See: https://www.power-eng.com/news/looking-for-a-good-scrubbing-todayrsquos-fgd-technology/#gref.

2 Introduction

2.1 Background

CCUS technology is continuing to advance in North America. Two development projects at coal-fired power stations have operated. Four additional applications to natural gas/combined cycle (NGCC) units and five applications to coal-fired units are planned. Success in generalizing CCUS technology and lowering cost and risk require these planned projects to proceed, supplemented by additional research and development on advanced concepts.

Key to a discussion of CCUS evolution is a definition of the varied scale and scope of testing. Table 2-1 summarizes the various categories of test facilities cited in this paper. Table 2-1 is not the sole interpretation of the varied stages of development but is proposed to enable discussion.

As described in Table 2-1, the first three categories are directed to exploratory studies, with large-scale tests best reflecting the authentic conditions encountered in commercial duty. The fourth, when operated over extended periods (ideally several years) serves as the basis to identify the technical and economic feasibility of an evolving process. Two such projects are either operating or on hold (pending economic conditions) and will be addressed in Section 3. However, there are nine projects presently conducting Front End Engineering Design (FEED) studies that are a first step to a large-scale project. The FEED study is a significant engineering undertaking whereby a system is designed, and a cost developed for a large-scale application. FEED projects are subsequently described for Section 3 for NGCC and Section 4 for coal-fired application.

The large-scale projects are a key step to ultimate commercialization. Ideally, commercialization is achieved when a process successfully operates over a wide range of coals, varied sites, and ambient conditions, as well as having a supplier who can provide a performance guarantee. Differences in fuel composition that determine trace and residual species such as sulfur trioxide (SO_3) and related aerosols, and trace metals may enable successful operation of a specific coal rank but not a second coal rank. Each test program and insight gained from the FEED studies will contribute to achieving this goal.

Table 2-1. Process Testing Categories

Facility	Description
Bench-scale	• Typically use synthetic gas created to simulate flue gas. • Employ laboratory hardware that is flexible. Provides insight to fundamental principles but does not reflect authentic duty. • Test duration is typically hours.
Small Pilot Scale	• Small size enables rapid parametric testing with authentic flue gas of key variables: mixing, residence time, or surface area per unit gas flow (for membrane-based systems). • Gas flow rate equivalent to that processed to deliver 0.25 MW to 5 MW. Lower range is typified by process equipment at National Carbon Capture Center. • Test duration can vary from hours to days/weeks depending on test objective. *Note: The higher end of the range – from 1MW to 5 MW – recently designated by the NETL as Engineered Scale but in this report treated as small pilot.*
Large Pilot Scale	• Processing gas flow equivalent to 5 MW to 25 MW. Offer more authentic conditions in terms of flue gas composition, surface area/volume ratio of reactor vessels. • Extended test duration to months and/or years. *Note: DOE considers 10 MW a minimum large pilot plant size with an upper limit of 25 MW.*
Large-Scale System	• Large-scale systems are at least 100 MW equivalent gas flow. • Operate for sustained periods – typically multiple years. • Facilities enable varying operating parameters but expose process equipment to authentic operating conditions, including startup/shutdown duty. *Note: Both the Boundary Dam Unit 3 and the NRG Petra Nova projects comprise large-scale tests.*

As of September 2021, there are 12 CCUS projects relevant to application in North America operating, capable of operating but on hold, or the subject of detailed engineering studies (typically referred to as Front End Engineering and Design, or FEED, studies). Figure 2-1 depicts the location of these projects throughout North America. Most have access to existing CO_2 pipelines or sites for either EOR or geologic sequestration. Of these projects, four address NGCC and eight pulverized coal-fired application. In addition, several large pilot plant tests are planned or in progress and numerous laboratory-scale investigations are looking to develop lower cost prospects.

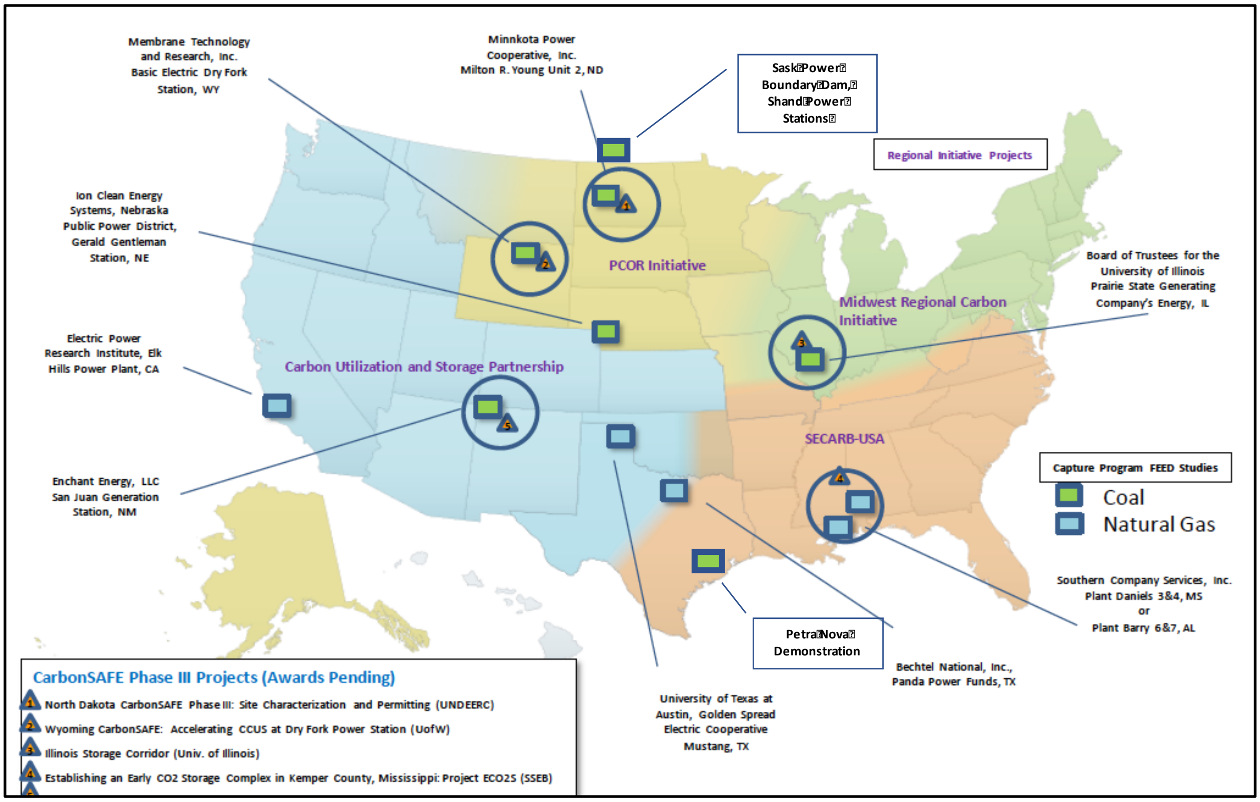

Figure 2-1. Location of CCUS NGCC and Coal-fired Projects in North America

The scope of this paper addresses both existing and planned large- or pilot-scale CO_2 capture projects that employ either absorption, adsorption, or membrane concepts. That the discussion focuses on recent North American projects is not meant to diminish the contribution of international work, but highlights activities with near-term payoff for U.S. application. Also addressed – and equally important – are pipeline construction and transport issues (including common carrier or "hub" concepts) as are CO_2 utilization for EOR and geologic sequestration. The cost basis for these projects is reviewed, including the role of Internal Revenue Service (IRS) tax credits thorough Section 45Q and other provisions. Although applicable only to new generation, the potential of the Allam-Fetvedt cycle as proposed by NET Power is addressed.

2.2 Evolution to NGCC Applications

Interest in CCUS application to NGCC has evolved considerably in recent years. There are numerous reasons for this shift, likely led by the anticipated prominent role of NGCC in future generation. It is insightful to compare the difference in process conditions between NGCC and coal-fired applications as a prelude to the discussion of CCUS projects for NGCC (Section 3) and coal-fired duty (Section 4).

Table 2-2 summarizes the key differences in gas composition from NGCC versus pulverized coal-fired applications that would be treated for CO_2 capture. The differences in application are described by four categories of gas characteristics: the concentration of CO_2 and O_2, trace constituents, gas temperature, and gas volume.

Table 2-2. Comparison of CCUS Process Conditions: NGCC vs. Pulverized Coal

Application	Gas Temp (ºF)	CO_2 (%)	H_2O (%)	SO_2 (ppm)	O_2 (%)	NOx (ppm)	Particulate Matter, Residual NH_3
NGCC	~260-280	~4	8	~0	15	~2-15	PM ~ negligible NH_3: ~1-2
Pulverized Coal	~135-200	~11-12	15	20-80	4-6	20-50	PM: 0.03 gr/scf NH_3 ~1-2 ppm

Concentration of CO_2 and Oxygen (O_2). The content of CO_2 in NGCC flue gas is about one-third of that in coal, due primarily to excess O_2 being two to three times higher in NGCC. The lower content of CO_2 has a mixed effect on capture efficiency. The lower gas content reduces the amount of CO_2 to be removed to achieve a target emission rate but reduces the "driving force" for high capture efficiency. The high excess O_2 in NGCC can complicate some processes. For example, the amine-based solvents are susceptible to oxidation and can lose effectiveness.

Trace Constituents. The most significant difference between NGCC and pulverized coal flue gas is the content of trace constituents, either from coal composition or the combustion process. Notable is the difference in sulfur dioxide (SO_2), which is negligible for NGCC but ranges up to 20-80 ppm for coal-fired, FGD-equipped units. As discussed in Section 4, CO_2 capture processes typically employ a SO_2 "polishing" step that lowered content to below 10 ppm.

Nitrogen oxides (NOx) will also vary. NGCC units with selective catalytic reduction (SCR) NOx control will contain approximately 5 ppm of NOx (@ 15 percent O_2). Further, the SCR process introduces residual NH_3 that can range up to 2 ppm or higher during load changes. The NOx concentration from coal-fired units is much higher as the nitrogen content of the coal is a key source. For most coal-fired units equipped with SCR, flue gas will contain 20 to 40 ppm. Pulverized coal units not equipped with SCR generate up to 100 ppm (@ 3 percent O_2) of NOx.

Gas Temperature. The temperature of gas processed from coal-fired units equipped with FGD is 80-125ºF lower than NGCC units. Water injected into wet or semi-dry FGD lowers temperature. This initial temperature can be important in the design and operation of 'pre-treatment" steps to further lower temperature and reduce SO_2 as previously described.

Gas Volume Processed. The gas flow processed per generator output (as MW) is typically larger for NGCC than for a coal-fired unit, despite the higher thermal efficiency which NGCC units usually exhibit. Comparing flue gas treated for CCUS from a subcritical pulverized coal versus a F-Class NGCC unit both generating 650 MW net after retrofit shows NGCC gas flow exceeds that from coal by 20 percent on a volume basis.[37] The gas volume to be treated varies with gas turbine design and combined cycle configuration and is largely due to excess O_2 content of 15 percent, compared to 3 percent to 5 percent O_2 typical of pulverized coal.

[37] DOE/NETL 2019 Cost and Performance Study. See comparison of gas flow rate entering CCUS process for Cases B31A/B and Case B11A/B. The relative magnitude will depend on the specifics of the gas turbine and NGCC configuration.

Boundary Dam 3 results identified issues with "amine health" induced by flue gas constituents, and recommended steps to extend solvent use[38] with lower SO_2 content being one factor. Particulate matter content is negligible for NGCC but can be 0.01-0.5 grains/dry scf for coal units. Particulates also are cited as a potential source for solvent degeneration.

2.3 Non-Utility (Industrial) Applications

CCUS experience on sources that are not electric generating units can be informative to utility duty. However, there are differences in gas composition – even greater than the differences between NGCC and pulverized coal electric generating units represented in Table 2-1 – that limit the applicability. Most notable is the difference in CO_2 content, which determines the "driving force" for CO_2 transfer from the gas stream to a solvent or solid media and thus cost of capture.

Figure 2-2 presents the CO_2 content of the gas stream (expressed as a concentration or mol basis) from 12 categories of industrial processes to which CCUS has been applied.[39] Figure 2-2 also shows the range of CO_2 content for electric generating units reported in Table 2-1.

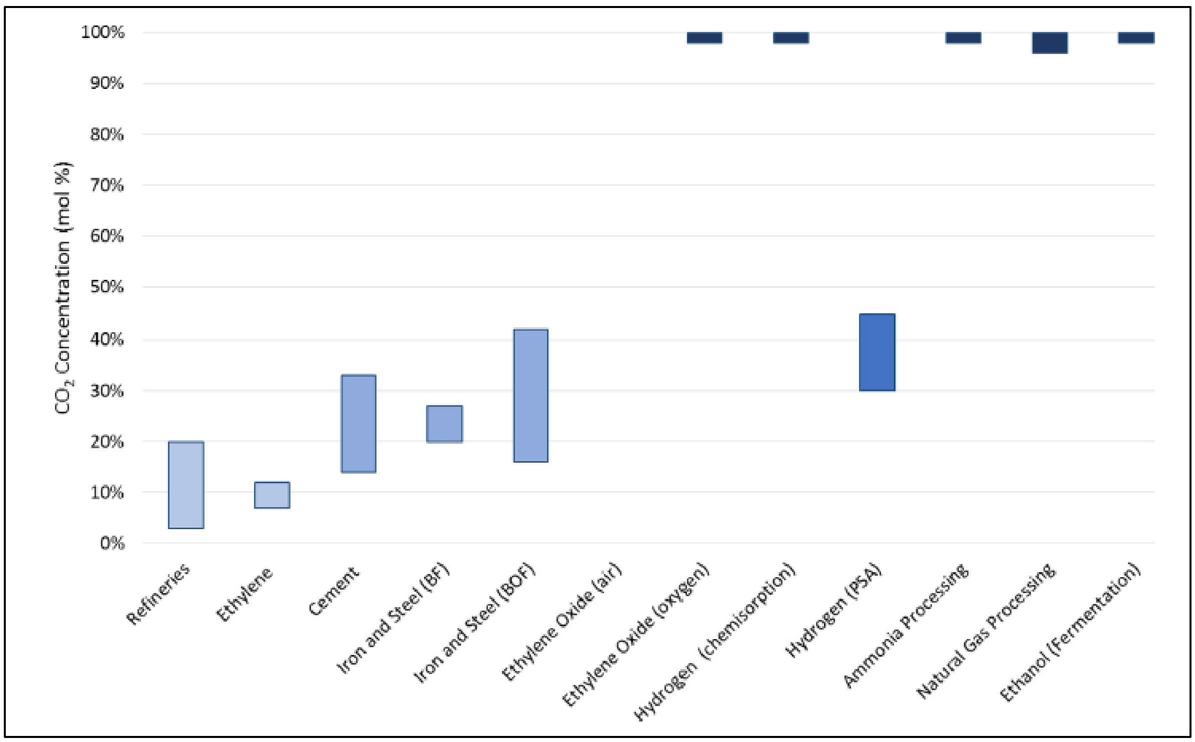

Figure 2-2. CO_2 Concentration (Mol Percent) of Various Industrial Sources

[38] Giannaris, S. et. al., SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability, 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15, 15th -25th March 2021, Abu Dhabi, UAE. Hereafter Giannaris et. al. 2021.

[39] Bains, P. et. al., CO_2 Capture from the Industry Sector, Progress in Energy and Combustion Science, 63 (2017) 146172.

Almost all industrial applications feature a CO_2 content exceeding that of electric generating units, some by a factor of up to eight to 10. Further, gas flowrate is typically far less for industrial application, thus simplifying design and contributing to lower cost. Other process features such as the temperature of the gas treated and the presence (or absence) of trace constituents affect performance and cost, too.

In summary, industrial experience can be insightful to utility applications but success at these conditions does not constitute a utility demonstration.

2.4 Process Categories

CO_2 flue gas capture processes are typically classified into four categories, as illustrated in Figure 2-3: absorption, adsorption, membranes, and cryogenic.

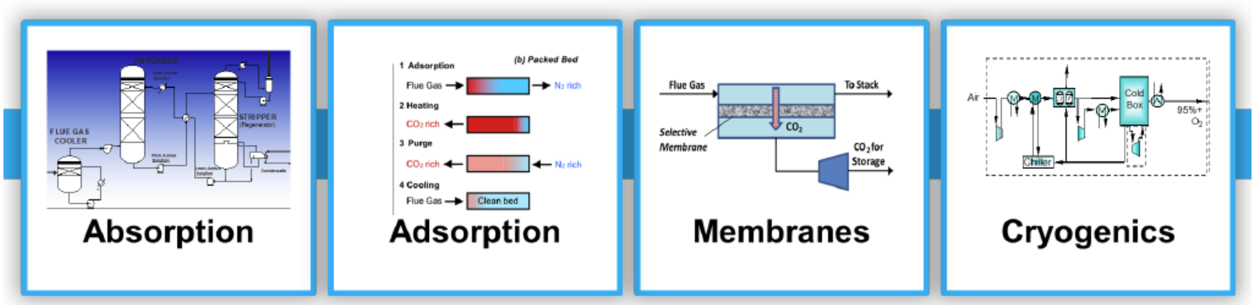

Figure 2-3. Four Categories of Capture Technology

(Source: EPRI Carbon Capture 101 Briefing, 2019)[40]

Absorption employs uptake of CO_2 into the bulk phase that forms a chemical or physical bond to a solvent or other carrier material. In contrast, *adsorption* is uptake onto the surface via a physical or chemical binding to a solid sorbent surface. *Membranes* employ variations in molecular permeation rates through porous material to separate compounds with different molecular structure. *Cryogenic* methodologies utilize difference in boiling points of gasses to separate by condensation.

Processes in any of these categories can provide effective CO_2 control over the long term. Each category features advantages and disadvantages in terms of CO_2 removal capability, energy penalty, and impacts on host plant operation. All four categories are equally applicable to natural gas and coal-fired flue gas. The fact that most large-scale operating processes and those subject to a FEED study are absorption and employ amine solvents does not designate this category as the preferred approach. Rather, the predominance of absorption processes employing amine-based solvents is a consequence of several factors. This includes the fact that amine-based solvents are well-suited to CO_2 concentration typical of combustion products as compared with natural gas processing. There also is experience to date with amine-based solvents, which

[40] Espinoza, N., Carbon Capture 101 Briefing, April 2019. Available at: http://www.curc.net/webfiles/CCS%20101%20Briefing%20Series/Briefing%202/EPRI%20Slides.pdf. Hereafter Espinoza 2019.

minimizes financing risk. And the familiarity of the electric power industry with absorption towers from FGD experience could also be a contributing factor.

Discussion of these categories and specific emerging technologies is presented in Section 5.

2.5 The Role of Large-Scale, Long-Term Tests

The electric power industry has a half century of experience identifying candidate control technologies, determining which is the most feasible, and proving these through various stages of bench-scale, pilot-scale, and large-scale projects. This approach was successful in developing the state-of-the-art advanced control technologies for particulate matter, FGD, and NOx that evolved from 1970s-era laboratory and pilot-scale studies.[41]

It is important to distinguish between an environmental control technology as either commercial or demonstration status. A control technology is considered commercial when a process or performance guarantee can be offered by a supplier, enabling the owner to enter into a business agreement with confidence. Demonstration-phase projects, almost without exception, require external funding – typically government – so the design includes significant margin to meet reliability or performance targets.

The same approach that evolved into present-day controls for PM, FGD, and NOx is being undertaken to develop feasible CO_2 removal processes. Long-term operation of large-scale projects is required to identify aspects of process operation not evident from laboratory or pilot plant testing. For example, second-generation amine-derived solvents for CO_2 absorption feature improved resistance to oxidation by O_2 and dissolved iron, nitrosation by NO_2, and production of aerosols by fine ash particles and sulfur trioxide.[42] Long-term tests at SaskPower Boundary Dam Unit 3 identified these shortcomings not observed in after previous laboratory tests. This experience was critical to identify issues with and solutions for amine heath.[43]

2.6 Value Chain

Successful use of CCUS to remove significant CO_2 from the national inventory requires not only reliable and effective capture technology, but the creation of an entire "value chain" of components. The key components in this value chain are CO_2 compression, transport, the disposition in a safe and ideally useful manner, and analytical and monitoring techniques.

First, compression technology is required to elevate CO_2 from atmospheric to high-pressure supercritical conditions, enabling effective transport and terrestrial injection. Second, pipeline

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[41] Flue Gas Desulfurization Systems: Design and Operating Considerations. Volume II, Technical Report. EPA-600/7-78-030b, March 1978. Available at: https://nepis.epa.gov.

[42] Accelerating Breakthrough Innovation in Carbon Capture, Utilization, and Storage: Report of the Mission Innovation Carbon Capture, Utilization, and Storage Experts Workshop: Mission Innovation, September 2017. Available at: https://www.energy.gov/fe/downloads/accelerating-breakthrough-innovation-carbon-capture-utilization-and-storage.

[43] Giannaris et. al. 2021.

infrastructure alone requires near-term investment for capital and labor estimated at $30.9 B and an additional $44.5 B by mid-century.[44] Pipeline design is expected to evolve from point-to-point duty to "common carrier" capabilities, which aggregate numerous sources to an array of storage sites.

Regarding CO_2 storage, EOR is an element of the CCUS value chain that earns revenue for the captured and compressed CO_2 byproduct. However, to fully support this revenue stream, the operation of target oil fields must be understood and optimized to maximize the tonnes of CO_2 stored per additional barrel of oil liberated. The terrestrial sequestration of CO_2 does not earn revenue and requires analysis to identify the best sites to provide for safe, long-term sequestration. Finally, monitoring technologies to account for CO_2 fate are expected to continue evolving.

2.7 Report Overview

This report is comprised on nine sections, including the Summary and an Introduction section. *NGCC Applications and Engineering Studies* are described in Section 3, followed by *Coal-Fired Applications and Engineering Studies* in Section 4. *Evolving CO_2 Capture Technologies* is presented in Section 5 while Section 6 discusses *Pipeline Transport*. The disposition of CO_2 is addressed in *Enhanced Oil Recovery (EOR)* (Section 7) followed by *Sequestration* (Section 8). The final Section 9 addresses *Installed Process Costs* which compares available cost data and the potential to offset costs through tax credits.

[44] Abramson, E. et. al., Transport Infrastructure for Carbon Capture and Storage, Great Plains Institute, June 2020.

3 NGCC Applications and Engineering Studies

As of September 2021, four NGCC units are the subject of FEED studies.[45] These are Golden Spread Cooperative Mustang Station (Denver City, TX), Panda Power (Temple, TX), Elk Hills Power Plant (Tupman, CA), and Mississippi Power Plant Daniel (Moss Point, MS). In addition, DOE/NETL completed a conceptual design and cost evaluation of a hypothetical reference.[46] A 2021 update of these results is expected to be available soon.[47]

Table 3-1 summarizes the key features of the four NGCC projects and presents results from the DOE/NETL reference study. Each host site is unique and will provide takeaways that can be applied to future applications. Table 2-1 summarizes for each host site the specific gas turbine, the arrangement of the heat recovery steam generator (HRSG) and steam turbine, gas volume processed, and CO_2 capture technology utilized. Also reported is the target CO_2 removal (as percentage reduction and in some cases annual tonnes), and the fate of CO_2 captured (e.g., EOR or sequestration). Where available, the length of CO_2 pipeline required and results of cost studies available as of September 2021 also are presented.

3.1 Golden Spread Electric Cooperative (GSEC) Mustang Station [48,49]

The GSEC Mustang Station employs two GE 7FA gas turbines, each equipped with a HRSG that supplies a single Alstom steam turbine generator (2 x 2 x 1 arrangement). The GE 7FA turbines employ dry low NOx combustion and generate less than 15 ppm (@15 percent O_2) of both NOx and CO. The flue gas flow volume is processed using a second-generation amine solvent and innovative absorption process design developed by the University of Texas at Austin and Honeywell/UOP.[50] This advanced amine solvent is of the class denoted as piperazine ($C_4H_{10}N_2$), which features two reactive amine groups per molecule, thus increasing CO_2 absorption capacity.

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[45] In October of 2021 the DOE awarded funds for three additional FEED studies that will initiate in 2022. These projects are identified in this section, but additional information is not publicly released.

[46] DOE/NETL 2019 Cost and Performance Study.

[47] Personal communication, Tim Fout of NETL, March 10, 2021.

[48] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study: NGCC at Denver City, TX. DE-FE0031844. U.S. Department of Energy National Energy Technology Laboratory Carbon Capture Front End Engineering Design Studies and CarbonSAFE 2020 Integrated Review Webinar, August-17-19 2020. Hereafter DOE/NETL CCUS August 2020 Review Webinar.

[49] Rochelle, G., CO_2 Capture from Natural Gas Combined Cycles, AWMA Virtual conference, November 17-18, 2020.

[50] UOP: formerly known as Universal Oil Products.

Table 3-1. NGCC CCUS Applications: Comparison of Key Site Features

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout)	Flue Gas Volume (Mft^3/h)	Capture Technology:	CO_2 Removal	CO_2 Fate	Pipeline Access	Site Feature	Cost Results: Reported or Expected
Golden Spread/ Mustang	430(g) (2 x 2 x 1)	90	Honeywell/ UT Austin. Second generation solvent (piperazine)	90% target	EOR	<5 mile to Este pipeline for 128-mile transport to Salt Creek	Several CO_2 pipelines converge; low-cost fuel for aux steam	End-of-Year (EOY) 2021
Panda/ Sherman	614(g)/594(n) (2 x 2 x 1) 741(g)/717(n) (w/duct firing)	144	Generic MEA conventional absorber/ stripper	90% target	- primary: saline fields, - secondary: EOR options	None at present but planned nearby	Nearby saline reservoir and EOR; planned pipeline for both options.	EOY 2021
Elk Hills	550(g) 2 x 2 x 1 (w/duct-firing)	99	Econamine FG^+	90% target (4,000 tonnes/d)	EOR, storage	Maximum ~ 8 miles within existing field	Existing oil reservoirs documented for EOR, storage	EOY 2021
Daniel 4	525(n) (2 x 2 x 1)	95	Linde-BASF OASE® blue solvent	90% target	Saline storage - Kemper County, MS	Pipeline requirement evaluated for multiple sources	Regional storage site proposed; costs ~$3-5/tonne	EOY 2021
DOE/NETL Reference	690(g)/646(n) (2 x 1 x 1)	160	CanSolv	90%	Off-site saline storage	Included in $3.5 /MWh		Capital: $1,595/kW CO_2 $/tonne: $80-102

The piperazine solvent has been tested at pilot scale since 2010, with results suggesting an increased CO_2 absorption capacity which reduces the size needed for the absorption tower. The process developer also reports piperazine features improved resistance to degradation, oxidation, and requires lower regeneration energy (2.8 GJ/tonne of CO_2 removed).

Captured CO_2 will be used at nearby EOR sites. Figure 3-1 depicts the advantageous conditions at the Denver City, TX site, with several CO_2 pipelines converging near the station. These existing CO_2 pipelines can be accessed with less than 1 mile of new pipeline and have in the past (August of 2020) earned a marketable value of $15/tonne of CO_2.

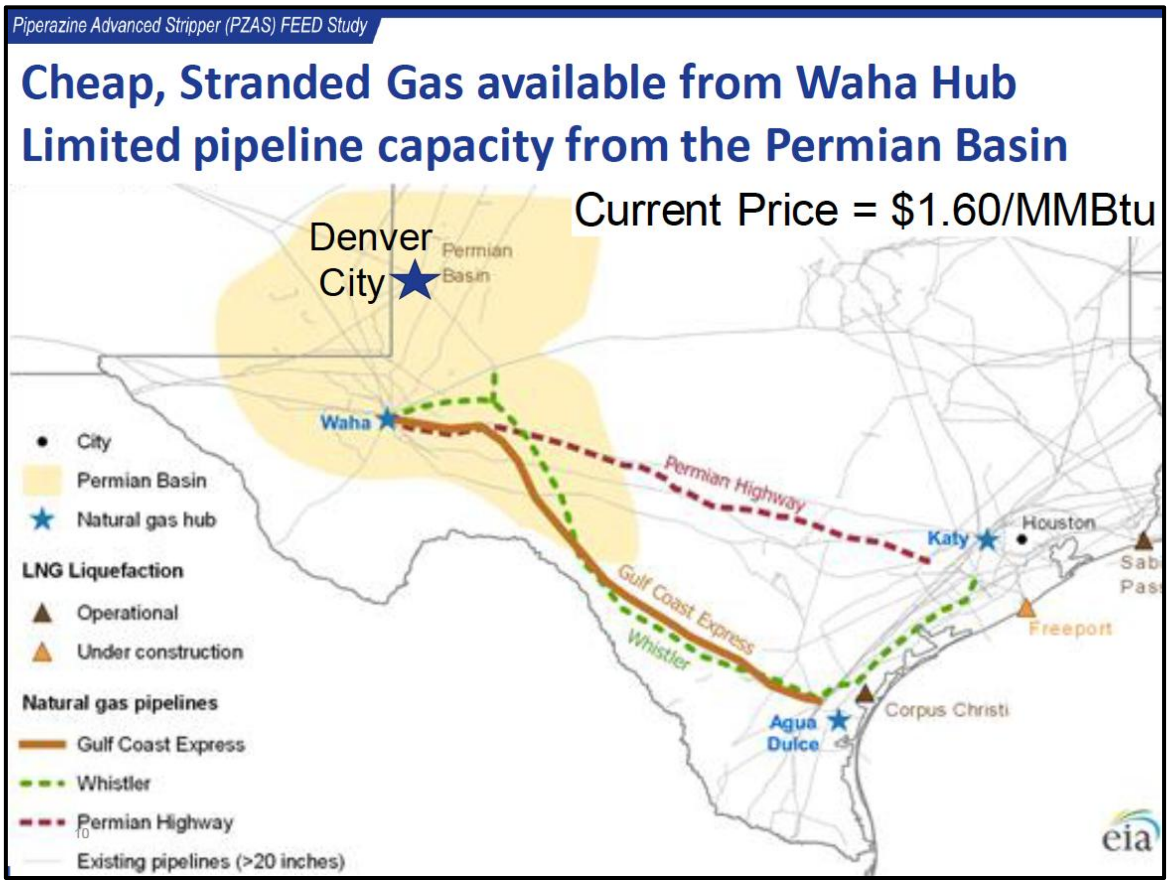

Figure 3-1. CO_2 Pipelines, Permian Basin Access to Mustang Station

A FEED study was to be completed in December 2021.

<u>Summary:</u> Based on pilot plant tests showing minimal heat absorption and resistance to oxidation, this second-generation piperazine sorbent could considerably reduce capital and operating cost. The site maximizes the opportunity for a reliable market for CO_2 for EOR.

3.2 Panda Sherman Power Project [51,52]

The Panda Sherman site employs the Siemens "Flex-Plant." It consists of two Siemens SGT6-5000F gas turbines, two Benson-type HRSGs equipped with duct-firing, and one SST6-5000 steam turbine (2 x 2 x 1 arrangement). The SGT6-5000 gas turbines are equipped with SCR, limiting NOx to less than 2 ppm (@ 15 percent O_2) while CO is limited to 10 ppm (@ 15 percent O_2.

A design FEED study is evaluating application of a generic MEA process to the gas flow volume as high as 144 M aft^3/h (at 185ºF) with duct burners.

Figure 3-2 presents the proposed plot plan depicting the relative footprint required for process equipment adjacent to the power generation equipment. The figure shows the location of the two absorber vessels with reported dimensions of 44.3 m in height (including absorption beds, water wash, and de-mister sections) and 11.8 m in diameter.

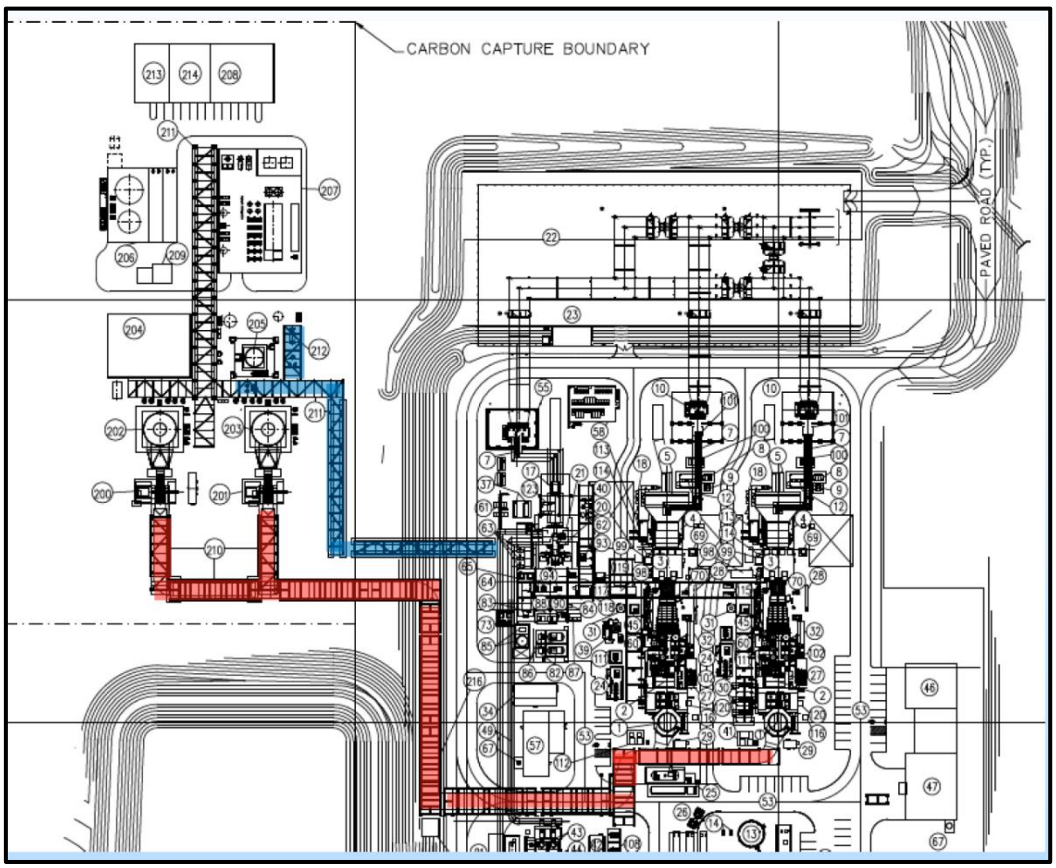

Figure 3-2. Plan Depicting CCUS Footprint: Panda Power

[51] See: https://www.power-eng.com/emissions/bechtel-siemens-panda-power-funds-dedicate-sherman-power-project-in-texas/#gref.

[52] Elliot, B., *FEED Study for Carbon Capture Plant Retrofit to a Natural Gas-Fired Combined Cycle Plant*, DE-FE0031848. DOE/NETL CCUS August 2020 Review Webinar.

The captured CO_2 is planned to be sequestered in a nearby saline reservoir, although local oil fields could deploy EOR. CO_2 pipelines are not installed at the site but locally accessible.

<u>Summary:</u> This study will explore how generic CCUS technology, employing a widely used amine sorbent, is applicable to NGCC stations that have good access to sequestration or EOR. A preliminary report was planned for completion in December 2021.

3.3 Elk Hills Power Plant [53]

Elk Hills features two GE 7FA gas turbines equipped with a HRSG that supply a single steam turbine generator (2 x 2 x 1 arrangement). The GE 7FA turbine exhaust is processed with SCR and generates less than 5 ppm (@15 percent O_2) of NOx and is equipped with oxidation catalysts for CO and VOC emissions. Both gas turbines are equipped with duct-firing.

Figure 3-3 depicts the CCS process equipment as envisioned to retrofit to the Elk Hills station, projecting the location of the gas absorber, direct contact cooler, and CO_2 stripper.

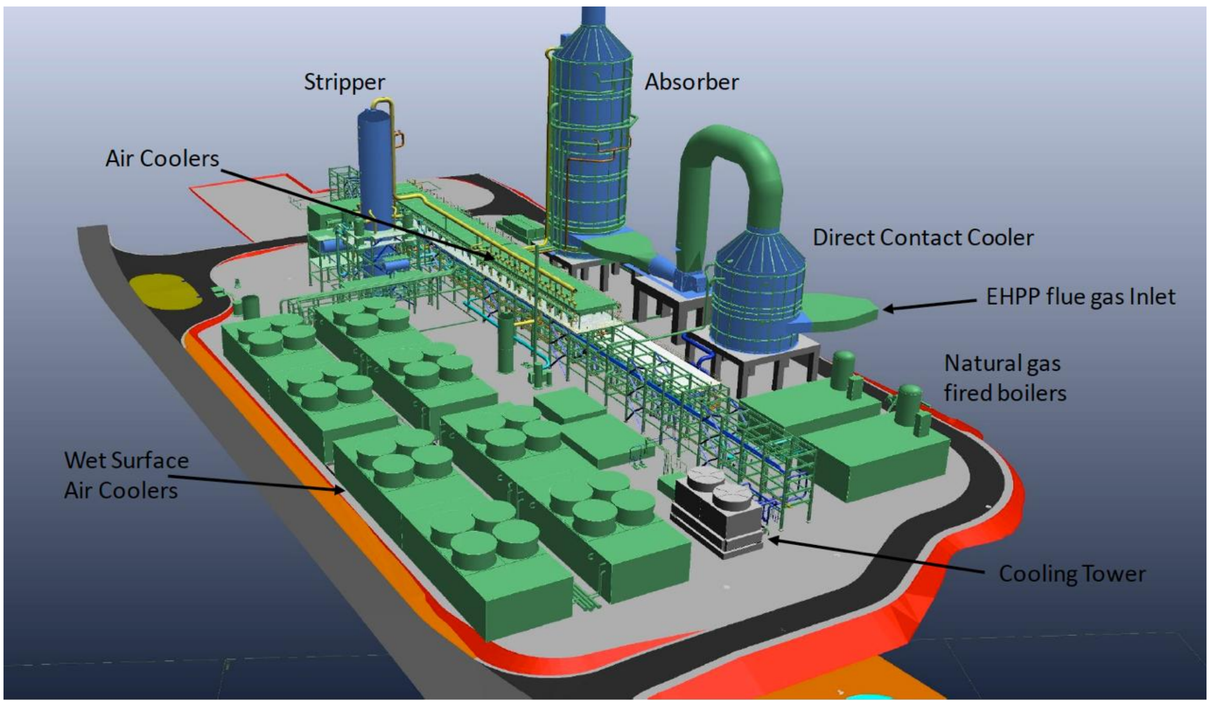

Figure 3-3. Depiction of Process Equipment as Installed: Elk Hills Power Plant

[53] Bhown, A., Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, DE-FE0031842. DOE/NETL CCUS August 2020 Review Webinar. Hereafter Bhown 2020.

The steam supply for solvent regeneration is provided by a separate package boiler. The Elk Hills location is severely constrained in terms of site access for construction.

A gas flow volume of 1.5 million aft^3/h (5 percent CO_2 at 200ºF) will be treated with the Fluor Econamine FG^{+SM} absorption process.[54] This second-generation solvent was developed based on 30 commercial (e.g., mainly non-utility) applications world-wide, including duty from 1991 through 2015 on gas turbine exhaust. Specifically, a 40 MW equivalent slipstream from the Bellingham NGCC station in Massachusetts employed an Econamine process for 85-95 percent CO_2 removal using a first-generation solvent.[55] Based on this experience, Fluor developed a second-generation solvent and a solvent maintenance program to minimize residual solvent emissions, auxiliary energy demand for regeneration, and solvent "loss" rate. Elk Hills will operate under a mandate to conserve fresh water and employs dry air coolers and wet surface coolers to eliminate or minimize water consumption.

The Elk Hills Power Plant is located within the Elk Hills oil field, offering nearby access to three oil reservoirs for EOR or sequestration. Figure 3-4 presents the location of the oil fields with respect to the power plant, showing an 8-mile pipeline enables delivery to all reservoirs.

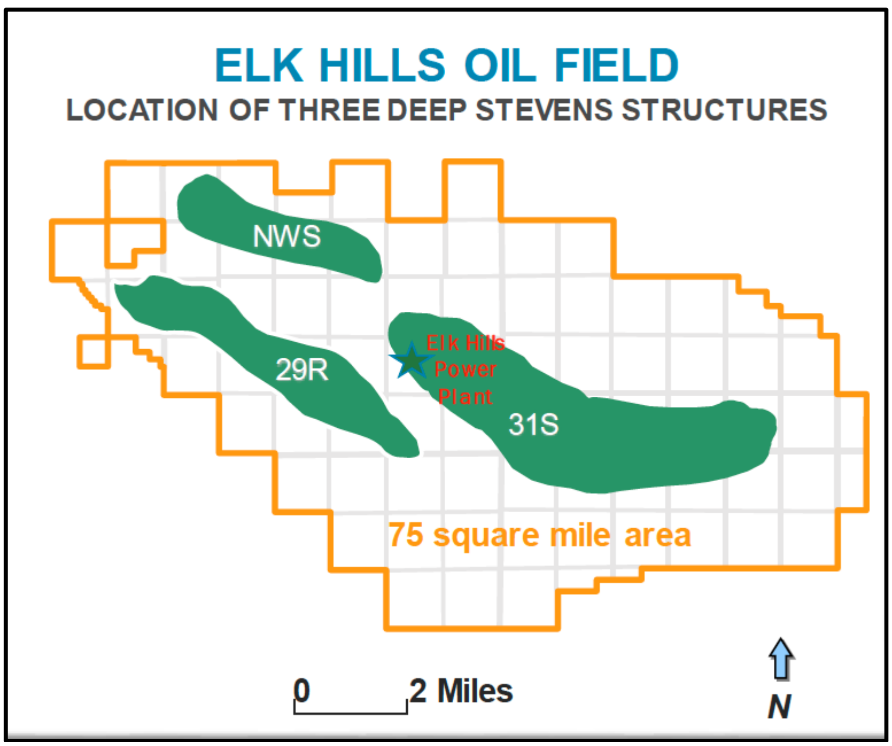

Figure 3-4. Location of Elk Hills Power Plant within the Elk Hills Oil Field

[54] Bhown, A. et. al., Front End Engineering Design Study for Carbon Capture at a Natural Gas Combined Cycle Power Plant in California, Proceedings of the 15th Greenhouse Gas Control Technologies Conference 15-18 March 2021.

[55] Capture CO_2 was purified and used within the food preparation industry. Available at: https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf.

The EOR and sequestration sites are well characterized, and any risk is well understood. The California Energy Commission cited Elk Hills as "…one of the most suitable locations for the extraction of hydrocarbons and the sequestration of CO_2 in North America."[56]

Summary: Elk Hills is characterized by a confluence of site conditions and oil production economics to support CCUS feasibility. In addition to proximity for EOR and revenue for oil production, the availability of Federal 45Q tax credits, the California Low Carbon Fuel Standard, the California Cap and Trade provision all provide financial support.

3.4 Mississippi Power Plant Daniel[57]

Daniel Units 3 and 4 each feature two GE 7FA gas turbines, one Vogt HRSG (triple pressure) and one GE TC2 D11 steam turbine, generating 525 MW net basis (2 x 2 x 1 arrangement).[58] The GE 7FA turbines are each equipped with SCR and generate less than 5 ppm (@15 percent O_2) of NOx. Plant Daniel Unit 4 has been selected as the basis of the current FEED study.

The estimated gas flow volume of 95 million aft^3/h (at 200ºF) is treated with the Linde-BASF amine absorption process, employing the BASF OASE® blue solvent.[59] This second-generation amine solvent was tested from 2009 through 2017 over a range of flue gases featuring different composition and impurities. The OASE blue solvent is reported to exhibit improved CO_2 absorption kinetics, reduced steam consumption, and minimal degradation from excess O_2. This enabled a lower sorbent circulation rate. The Linde-BASF process arrangement also minimizes water wash-induced solvent losses, and regenerates CO_2 at higher pressures (3.4 bars), thus lowering compression work and CO_2 transport cost.

The results of the design evaluation – to have been available in 4Q 2021 – will define the gas ductwork arrangement, integration with the steam cycle, and utility requirements in terms of auxiliary power, the supply of water (deionized, potable, and process), and instrument air.

A regional strategy for CO_2 sequestration is being evaluated that would aggregate CO_2 from two additional generating stations[60] to a site in Kemper County (MS). A preliminary study identified potentially up to 900 million tonnes of CO_2 could be stored for \$3/tonne to \$5/tonne (excluding transport). The Kemper County site will require a CO_2 pipeline transport distance of 5 miles and Class VI injection wells. Further details of the sequestration options for this site are presented in Section 8.

[56] Appendix F, URS Report on CO_2 Sequestration for California Energy Commission. 2010

[57] Lunsford, L, *Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant*, DE-FE0031847. DOE/NETL CCUS August 2020 Review Webinar.

[58] Alabama Power Barry Units 6 and 7 comprise an identical unit design and arrangement to which the results of this evaluation are expected to be equally applicable. See prior footnoted reference for details.

[59] Additional BASF reference.

[60] Plant Ratcliffe (NGCC) and Plant Miller (coal) are candidate CO_2 sources for storage at Kemper County. See Lunsford 2020.

3.5 DOE/NETL Reference Case [61]

DOE/NETL evaluated CCUS cost for a "greenfield" unit comprised of two 2017-vintage F-Class gas turbines, two 3-pressure reheat HRSGs, and one 3-pressure reheat, triple admission steam turbine (2 x 2 x 1 arrangement). (DOE/NETL was revising this study, with an anticipated release date of late 2021).[62] The two gas turbines each produce 238 MW gross and the HRSG provides steam for a 263 MW steam turbine. The gas turbines are equipped with SCR NOx control limiting emissions to 1.8 ppm (@ 15 percent O_2) while an oxidation catalyst limits CO to 1 ppm (@ 15 percent O_2).

The gas flow volume from these units (not equipped with duct burners) is 153 million aft^3/h (at 23ºF) and is processed with a generic amine-based absorption process (Cansolv).

Figure 3-5 reproduces the block flow diagram for this hypothetical CO_2 capture application, which provides the basis for a mass and energy balance to specify process equipment.

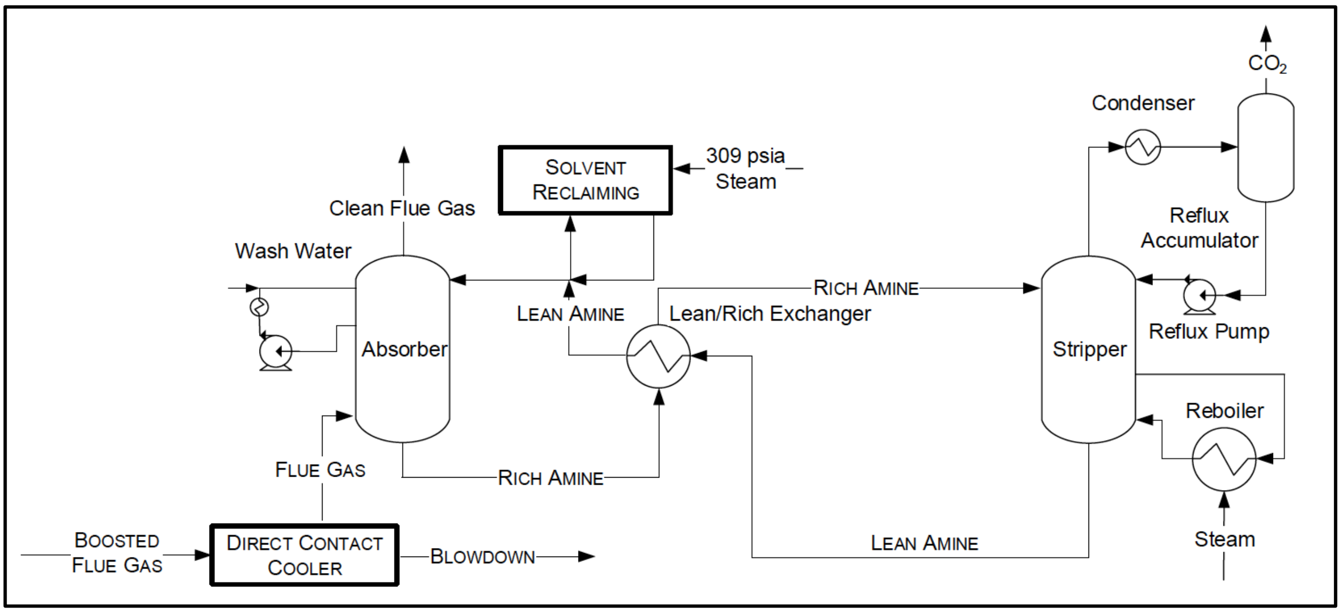

Figure 3-5. Simplified Block Flow Diagram: Cansolv CCUS to 550 $MW_{(n)}$ NGCC

The analysis assumes CO_2 is sequestered off-site in a saline reservoir. The cost for pipeline, sequestration site characterization and monitoring, and construction and operation of the Class VI injection wells are assumed to be $3.5/MWh.

Figures 3-6 and 3-7 present results – as reproduced from the DOE/NETL report – of the capital requirement and levelized cost for this NGCC unit equipped with CCUS.

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[61] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, NETL-PUB-22638, September 24, 2019. Hereafter NETL Bituminous and NGCC 2019 Reference Study.

[62] Personal communication, Tim Fout of NETL, March 10, 2021; updated September 14, 2021.

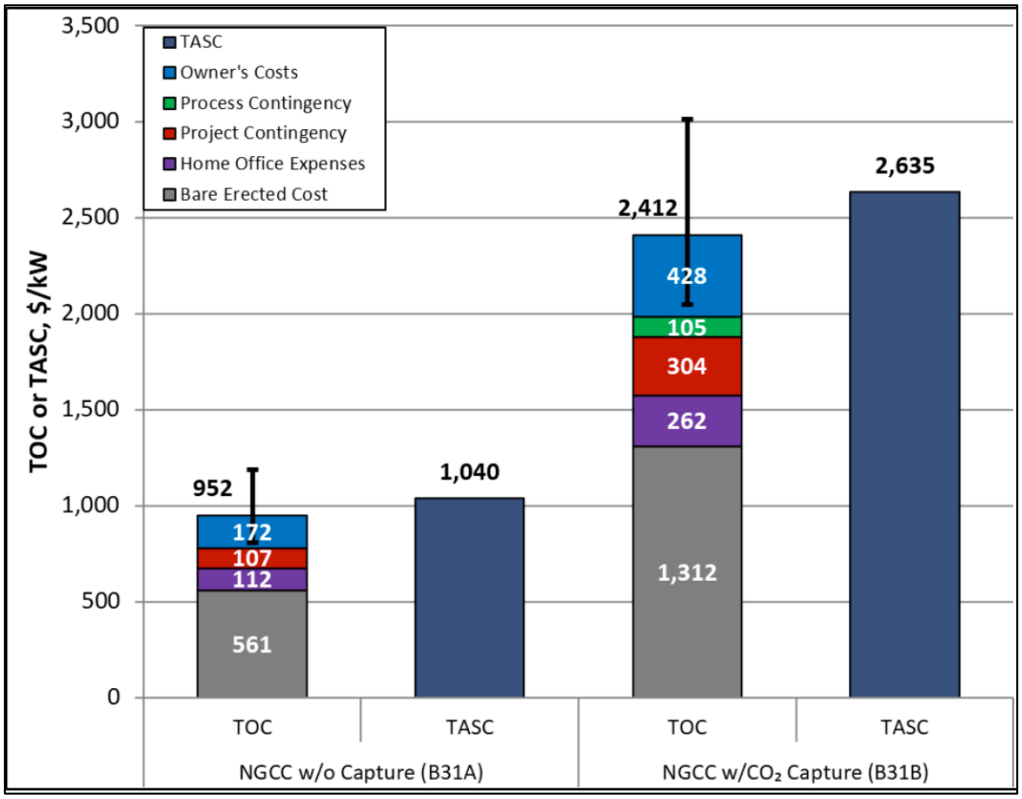

Figure 3-6. Capital Cost for DOE/NETL Reference Study: NGCC Application

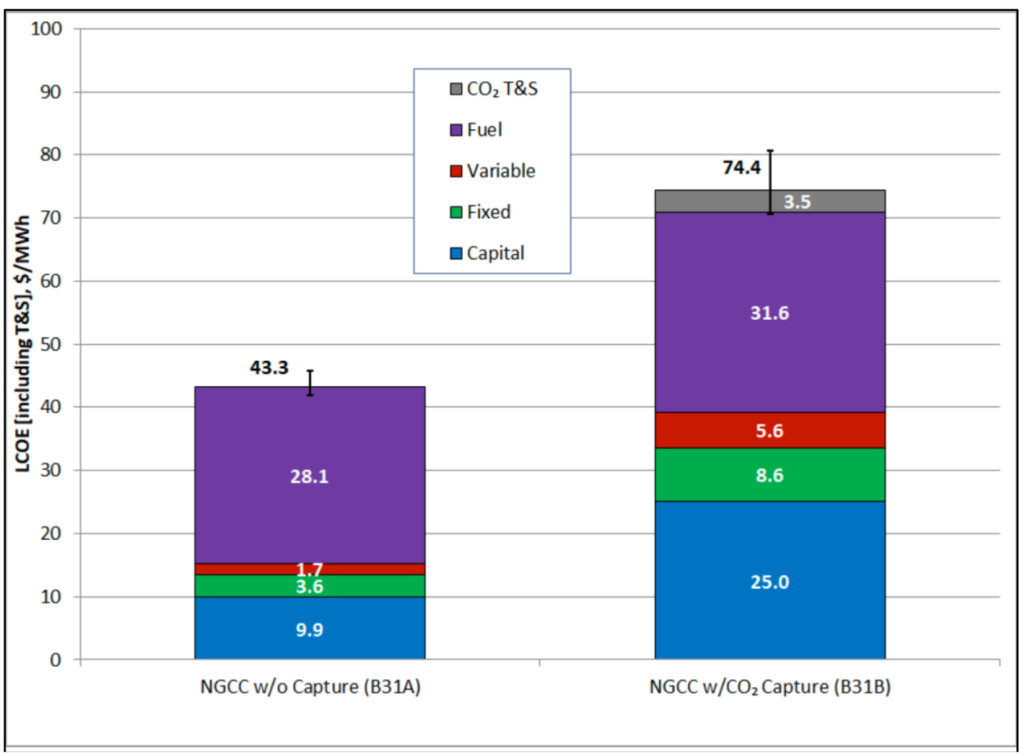

Figure 3-7. Cost Results for DOE/NETL Reference Study: Capital, LCOE

Figure 3-6 reports several cost metrics. The total cost incurred by the owner is show as the *Total As-Spent Capital* (TASC, depicted on the far right). This includes all costs, including any escalation over the construction period and financing charges. This cost is distinguished from the *Total Overnight Costs* (TOC) reported by DOE, which reflect all costs but reported for "overnight" installation.

Figure 3-7 presents the Levelized Cost of Electricity, based on 85 percent capacity factor and 30-year operating lifetime along with financing charges that reflect typical utility conditions.

Figure 3-6 shows that for a conventional amine-based CCUS process the capital cost incurred by the owner (Total As-Spent Capital) more than doubles the cost for the generating unit, adding approximately $1,595/kW. Figure 3-7 shows the Levelized Cost of Electricity (LCOE) attributable to CCUS is $74.4/MWh, exceeding the Baseline Case ($43.3/MWh without CCUS) by $31.1/MWh. The largest component of this levelized cost is the additional fuel to support the CCUS process, followed by capital.

DOE/NETL also determined the cost to avoid CO_2 on a $/tonne basis for the same design and operating conditions adopted to determine the levelized cost of electricity. DOE/NETL report the cost to avoid CO_2 of $102/tonne, including transportation and storage. If the captured CO_2 can be sold at the plant boundary for EOR and the cost for transport is adopted by the buyer, the avoided cost of $80/tonne is a "breakeven" market price for process equipment and operation.

3.6 Observations: Potential CCUS Application to NGCC

The following observations are offered for NGCC CCUS application, based on the FEED studies for the four planned projects and the DOE/NETL evaluation:

- Each of these NGCC applications – all amine–based absorption – employ either a second-generation solvent or process design with improved energy utilization that can lower both operating and capital cost. The savings will be quantified by completing FEED studies and assessing risks.

- Three sites – Elk Hills, Golden Spread, and Panda – have unique features that maximize CO_2 utilization or sequestration, due to proximity of CO_2 pipelines or an adjacent saline field for sequestration. These conditions lower incurred costs and/or provide EOR revenue that will offset project investment. A FEED study for Elk Hills was scheduled for competition December 2021.

- The hypothetical 550 M unit evaluated by DOE/NETL that is based on CCUS applications employing 2017 generic technology is currently the sole reference case with costs. DOE/NETL results imply CCUS adds approximately 150 percent to the capital cost for NGCC without CCUS. The Levelized Cost of Electricity for the CCUS-equipped unit increases by 70 percent. These costs include pipeline transport and sequestration but do not reflect Section 45Q or similar tax credits. Nor does do they reflect other financial considerations, such as a local or state CO_2 carbon market. The potential role of Section 45Q credits are addressed in Section 9.

- DOE has awarded three additional FEED studies to address advanced CCUS application to NGCC units.[63] Calpine Texas CCUS Holdings will explore adopting a modular, second-generation Cansolv CCUS process to Calpine's Deer Park NGCC power station. ION Clean Energy will evaluate CCUS application to Calpine's Delta Energy Center NGCC unit, employing ION's second-generation "ICE-21" solvent. GE Gas Power will explore CCUS application to an existing F-Class NGCC site, employing GE's "Gen 2" technology. Further information describing these recent awards was not available at the time of report release.

[63] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

4 Coal-Fired Applications and Engineering Studies

Section 4 addresses coal-fired large-scale CCUS retrofit projects in North America, either currently operating or on hold, or the subject of FEED or other engineering studies. A total of nine projects or studies are underway in North America.

The operating and on-hold projects are:

- SaskPower Boundary Dam Unit 3 (Estevan, Saskatchewan), which is presently operating.
- NRG Petra Nova project (near Houston, TX), which has placed operation "on hold" since May 1, 2020.[64]

Projects where FEED design studies are underway are:

- Minnkota Power Cooperative Milton R. Young Station (Center, ND),
- Basin Electric Dry Fork Station (Gillette, WY),
- Nebraska Public Power District Gerald Gentleman Station (Sutherland, NE),
- Enchant Energy San Juan Generating Station (Waterflow, NM),
- Prairie State Generating Company Unit 2 (Marissa, IL), and
- SaskPower Shand (Estevan, Saskatchewan).

In addition, NGCC, DOE/NETL issued a conceptual design and cost for a hypothetical reference case similar to NGCC.

Table 4-1 describes for each host site the gas volume processed, CO_2 capture technology utilized and target removal, and the fate of CO_2 captured. Where available, the length of CO_2 pipeline required and the projected CCUS capital cost are cited.

[64] See: https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html#:~:text=Given%20the%20current%20status%20of,online%20when%20economic%20conditions%20improve.

Table 4-1. Coal-Fired CCUS Applications: Comparison of Key Site Features

Station/ Unit	Capacity, MW [gross(g) or net (n)]	Flue Gas Volume (Maft^3/h)	Capture Technology	Target CO_2 Removal (%, daily rate)	CO_2 Fate	Pipeline Required	Unique Site Feature	Cost Results: Reported or Pending
SaskPower/ Boundary Dam 3	150(g) 111(n)	25.9	CanSolv amine: SO_2, CO_2	90% target. (3,200 tonnes/d)	EOR at Weyburn, Midale fields (70 km) or storage (~1.2 km)	Existing	EOR plus within 1.2 km of saline storage	$1.2B, 50% for CCUS or ~$5,405/kW. CO_2 $/tonne: 110
NRG Petra Nova W.A. Parish Unit 8	240(n)	41.4	Proprietary KM-CDR amine solvent	90% target	EOR in West Ranch, TX oil field	83 miles	Proximity to EOR options	Total $1B; $600M for CCS. CO_2 $/ton: 67
Milton R. Young/ Minnkota Power Co-op	477(g)	79.9	Econamine FG$^+$	90% target (11,000 tonnes/d)	Storage in saline reservoir	Negligible	Saline reservoir at station, adjacent coal mine	EOY 2022
Dry Fork/ Basin Electric	422(g) 385(n)	70.7	MTR Polaris membrane	70% target	Saline storage - Campbell County, WY	TBD	Saline reservoir near station	EOY 2021

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout)	Flue Gas Volume (Maft^3/h)	Capture Technology:	Target CO_2 Removal (%, mass if reported)	CO_2 Fate	Pipeline Required	Unique Site Feature	Cost Results: Reported or Pending
Nebraska Public Power District /Gerald Gentleman	CCUS module 300 MWe (total plant 700 MW gross basis)	57.8	Ion Clean Energy solvent	90% (1.9 M tonnes/y)	EOR	Not addressed		Previous: $1,310/kW. CO_2 $/tonne: 33
Enchant Energy/San Juan Units 1-4	914 (g) 601 (n)	165.5	MHI amine solvent	90%	Storage, with EOR to Permian Basin alternate	~20 miles	Nearby storage formations, Cortez pipeline to EOR	Preliminary study: $2,150/kW. CO_2 $/tonne: ~43
Prairie State Generating Company	816 (g)	123.1	MHI KM-CDR	90%	Off-site saline storage	Cost included in $10/tonne storage cost	Utilize DOE Illinois Storage Corridor	TBD
SaskPower Shand	305(g) 279 (n)	61	KM CDR Process	90%	EOR at Weyburn, Midale	~12 km pipeline to BD3 required	Utilizes existing Weyburn, Midale sites	$2,121/kW CO_2 $/tonne: 45
DOE/NETL Reference	690(g) 646(n)	153	CanSolv	90%	Off-site saline storage	Included in $10/tonne disposition cost		Capital: $840.2M, $1,539/kW CO_2 $/tonne: 55-70

4.1 Boundary Dam [65,66,67]

The Boundary Dam Unit 3 (BDU3) project fires Canadian lignite and has operated since 2014 with an early generation of the CanSolv absorption process. It is budgeted at approximately $1.2 B (USD), of which $240 M is provided by the Canadian government. Unit 3 was initially designed to provide 150 MW (gross) but would incur an auxiliary power penalty limiting net power output to 81 MW by adopting early generation process equipment. However, the use of several innovative means to maximize residual heat utilization reduced the penalty, enabling a net power output of 110 MW.

The CanSolv process employs conventional amine reagent and is designed for 90 percent CO_2 removal. Inherent to this process is capability to limit SO_2 to single-digits (ppm basis) and lower particulate matter content, both necessary to retain amine performance. The amine SO_2 removal step elevates total removal to 99 percent, with captured effluent regenerated as sulfuric acid. CO_2 is regenerated from the CO_2 capture train with steam extracted from the low-pressure turbine.

Regenerated CO_2 is compressed to 2,500 psig and transported 70 km by pipeline for EOR at the Weyburn oilfield, where it is injected 1.7 km underground. Any CO_2 not employed at Weyburn is transported 2 km for sequestration in the Deadwood saline aquifer (referred to as Aquistore).

The Boundary Dam Unit 3 project required both retrofit of process equipment and refurbishing power generation components to support 30-year operation. Power generation refurbishment focused upon a replacement of the steam turbine and the electric power generator.

The 90 percent CO_2 removal target – equivalent to removing 3,200 tonnes of CO_2 per day – was attained one year after startup. Figure 4-1 presents a histogram of CO_2 capture plant availability from early 2014 through mid-2020. Figure 4-2 presents the daily CO_2 removal rate from late 2015 through mid-2019 and shows after two years CO_2 removal of 88 percent to 93 percent was attained when planned outages did not limit duty. Figure 4-1 shows achieving CO_2 capture plant availability of 90 percent or 3,200 tonnes per day is attained in three of the six full operating years, although three of the last four were so achieved**.** It is not known if any of the “shortfalls” in CO_2 plant availability were imposed by process issues, pipeline or EOR/storage limits, or other reasons not related to CCUS operation.

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[65] Srisang, W. et. al., *Maximization of Net Output for Boundary Dam Unit 3 Carbon Dioxide Capture Demonstration Project*, 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, 21st -25th October 2018, Melbourne, Australia
[66] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, presented August 16, 2019, Pittsburgh, PA.
[67] Giannaris, S. et. al., SaskPower’s Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability, 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15, 15th -25th March 2021, Abu Dhabi, UAE. Hereafter Giannaris et. al. 2021.

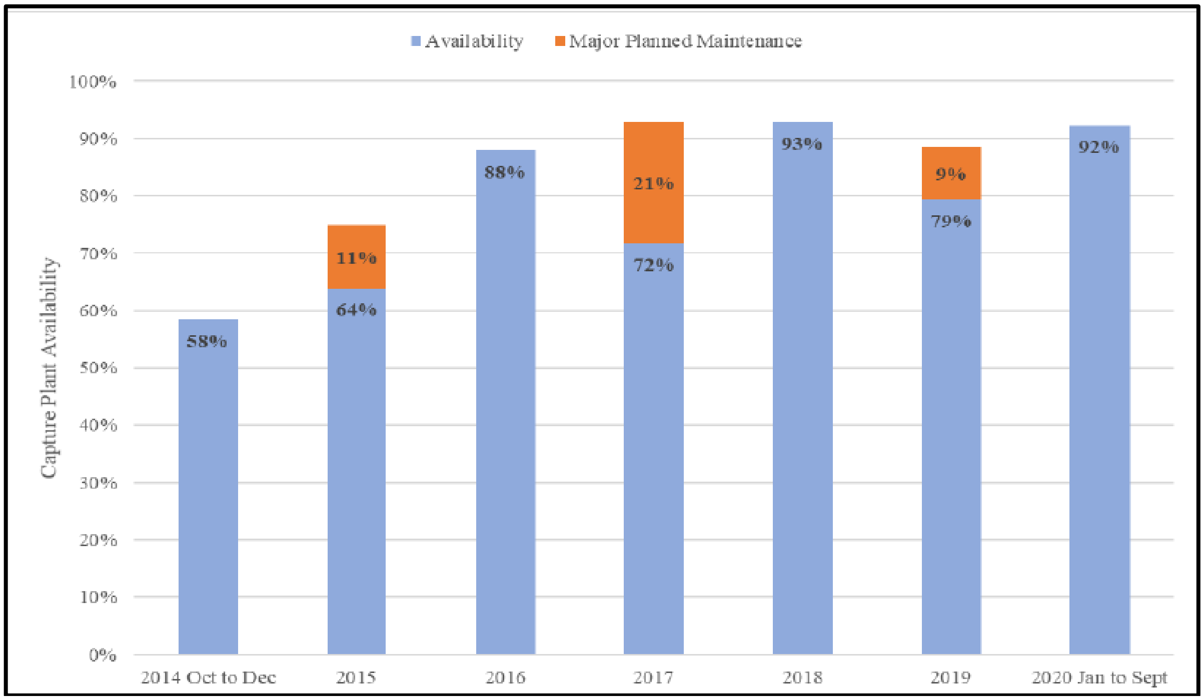

Figure 4-1. Boundary Dam Unit 3 CCS Process Availability: 2014 through Mid-2020

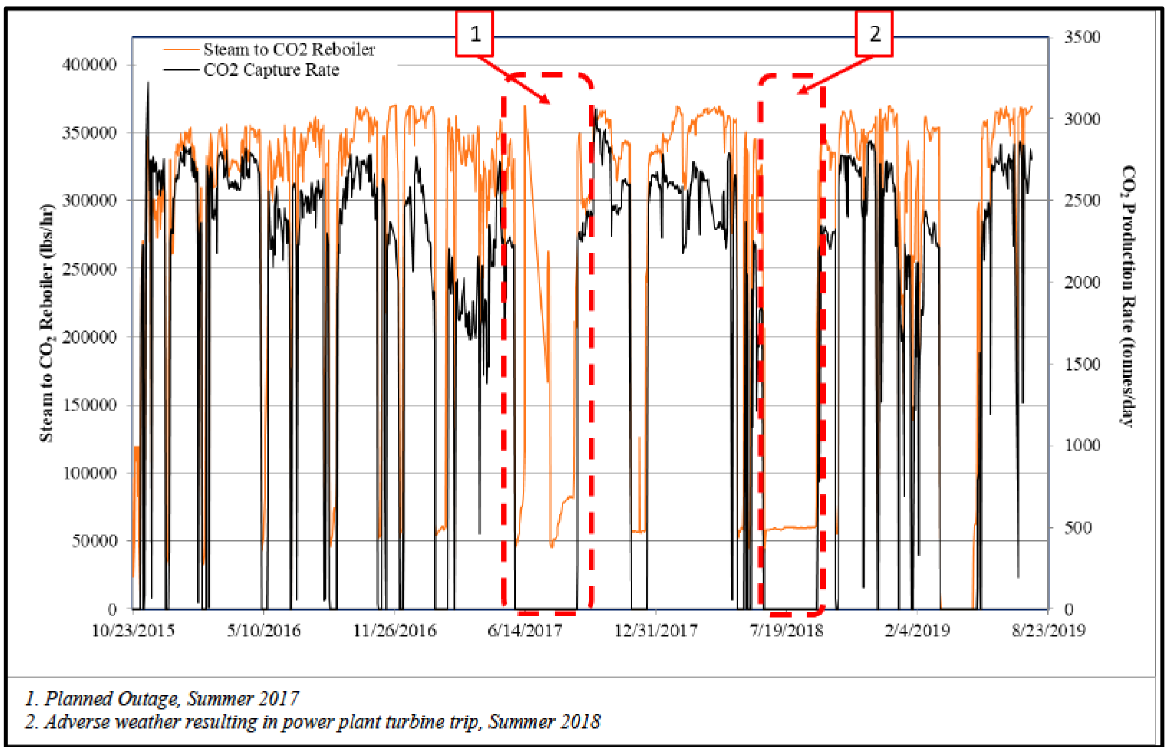

Figure 4-2. Boundary Dam Unit 3 CCS Process CO_2 Daily Removal, Reboiler Demand

SaskPower identified the reliability shortcomings in the first three years and implemented corrective measures. These include resolving compressor issues, compromise of amine performance due to fly ash contamination, fly ash fouling of de-misters, re-boiler performance, and heat exchanger shortcomings. These issues were corrected in 2015 and 2017 outages.

SaskPower reported capital cost for process equipment for this first-of-a-kind facility, including plant refurbishment, of $1.2 B (U.S). Of that. $240 M was contributed by the Canadian government.[68] SaskPower reported 50 percent of the cost is attributable to the CO_2 capture and regeneration process, 30 percent for power plant refurbishment, and 20 percent for other emissions control and other efficiency upgrades.[69] Consequently, $600 M of capital is associated with the CCUS retrofit, equivalent to $5,405/kW (net). The levelized cost per tonne of CO_2 avoided, as reported by the CCS Knowledge Center, is $105/tonne. This is based on a capacity factor of 85 percent, operating lifetime of 30 years, and a credit for CO_2 as EOR.[70]

Summary. Boundary Dam 3 is a first-of-a-kind facility "learning experience" that incurred capital cost atypical of that anticipated for future applications. It identified innovative means to reduce auxiliary power consumption from 42 percent of gross power to 28 percent. Several initial process shortcomings were turned into lessons learned to improve reliability and lower cost. The payoff is manifest in the design for the SaskPower Shand station.

4.2 NRG Petra Nova [71]

The NRG Petra Nova CCS project is- a 240 MW module retrofit to Unit 8 of the Powder River Basin (PRB) fired W.A. Parish Generating Station. It employs state-of-art SCR for NOx control, wet FGD for SO_2, and fabric filters for particulate matter. This test module operated from 2014 to mid-2020, employing the MHI Advanced Kansai Mitsubishi Carbon Recovery Process (KM-CDR) absorption process. KM-CDR is a second-generation solvent, developed by MHI and Kansai Electric Power Company and tested 25 MW pilot scale at Alabama Power's Barry Station.

The Petra Nova project was budgeted at $1 B, of which $190 M was provided by DOE. It was designed for 90 percent CO_2 removal. Typical of all coal-fired CO_2 capture technology, pre-treatment with a flue gas "quencher" to lower gas temperature, SO_2, and other trace species is required to provide solvent longevity. Flue gas exiting the quencher proceeds to an absorption tower for CO_2 removal, then regeneration in a stripper tower that maximizes utilization of low-grade heat. A small portion of the sorbent is extracted for filtering to remove contaminants and replaced with fresh sorbent.

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[68] See: https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/

[69] Giannaris et. al. 2021.

[70] *The Shand CCS Feasibility Study Public Report*, November 2018, CCS Knowledge Center. Available at See: https://ccsknowledge.com/initiatives/2nd-generation-ccs---Shand-study. Hereafter Shand 2018 Feasibility Report.

[71] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, PETRA NOVA PARISH HOLDINGS LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.

Like Boundary Dam, the optimal source of steam for sorbent regeneration is a separate source. In this case it is a retrofit GE 7FA gas turbine equipped with a HRSG. This unit provides both auxiliary power and steam for CCUS operation, while excess power is sold into the energy grid.

CO_2 upon regeneration is compressed to 1,900 psig and transported 81 miles by pipeline for EOR at the West Ranch site, requiring injection between 5,000 feet to 6,000 feet underground.

Table 4-2 presents a summary of CO_2 (short tons) planned for capture (at 85 percent capacity factor) and short tons actually captured from 2017 through 2019. The table shows that – like Boundary Dam Unit 3 – the CO_2 captured at Petra Nova increased annually. By 2019, 95 percent of the planned capture (based on an 85 percent operating factor) was achieved. The primary reason for the increase in CO_2 removal was the improved process reliability achieved each year. Factors compromising operation (corrosion, compressor, and heat exchanger performance) were identified and resolved.

Table 4-2. Petra Nova CCUS CO_2 Capture Metrics

Year	Planned CO_2 Capture (Short Tons)	Actual CO_2 Capture (Short Tons)	Percent of Planned CO_2 Capture (@85% Operating Factor)
2017	1,635,919	1,180,594	72
2018	1,392,300	1,122,050	81
2019	1,613,300	1,529,174	95

Approximately 60 percent of the $1 B project investment was directed to capital for the CO_2 capture and cogeneration facilities. The funding includes DOE grants ($190 M), financing ($325 M), and sponsor equity ($300 M). The implied CO_2 capture capital cost of $600 M translates into approximately $2,500 /kW.[72] The balance of $400 M was dedicated to the project's share of the CO_2 pipeline, additional injection wells at the West Ranch oil field, and other up-front and administrative costs. The cost to avoid CO_2 in terms of a $/ton basis is not generally disclosed in the public domain. However, several observers estimate this cost to be $60-65/ton.[73]

<u>Summary</u>. The Petra Nova project, employing absorption CO_2 capture with a second-generation solvent, exhibited continual improvement in CO_2 capture. By the third year, the project captured 95 percent of the planned value. As observed with Boundary Dam Unit 3, reliability in the initial years caused the operating factor to be less than the 85 percent target. Causes of the shortfall ultimately were identified and rectified. The second-generation amine solvent exhibits better operating characteristics (longevity, corrosion resistance). Lessons from predecessor studies lowered capital charge to an estimated $2,500/kW.

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[72] See: https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/.

[73] Technology Readiness and costs for CCS, March 2021, prepared by the CCS Institute. See Figure 16. Available at: https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/.

4.3 Minnkota Power Cooperative/Milton R. Young [74,75]

Minnkota Power Cooperative's Milton R. Young Unit 2 is the host for a FEED study of Fluor's Econamine FG Plus[SM] process. This is the same absorption process evaluated for the Elk Hills unit. This 477 MW lignite-fired unit is equipped with a wet FGD process, an electrostatic precipitator (ESP) for particulate control, and combustion NOx controls. This CO_2 capture design for coal flue gas is based on a pilot plant (70 tonnes per day) that operated from 2012 to 2015 at E. On's generating station in Wilhelmshaven, Germany.[76] The Milton R. Young station offers the ability to sequester captured CO_2 below the station footprint, thus eliminating the need for CO_2 pipeline. Figure 4-3 presents a rendering of the generating station and sequestration site. As an alternative to sequestration, the project may make the CO_2 available for purchase by EOR operators in the Williston Basin. This would require construction of approximately 100 miles of CO_2 pipeline. CO_2 sold for EOR would be subject to certain conditions regarding care, custody, and long-term storage of delivered CO_2.

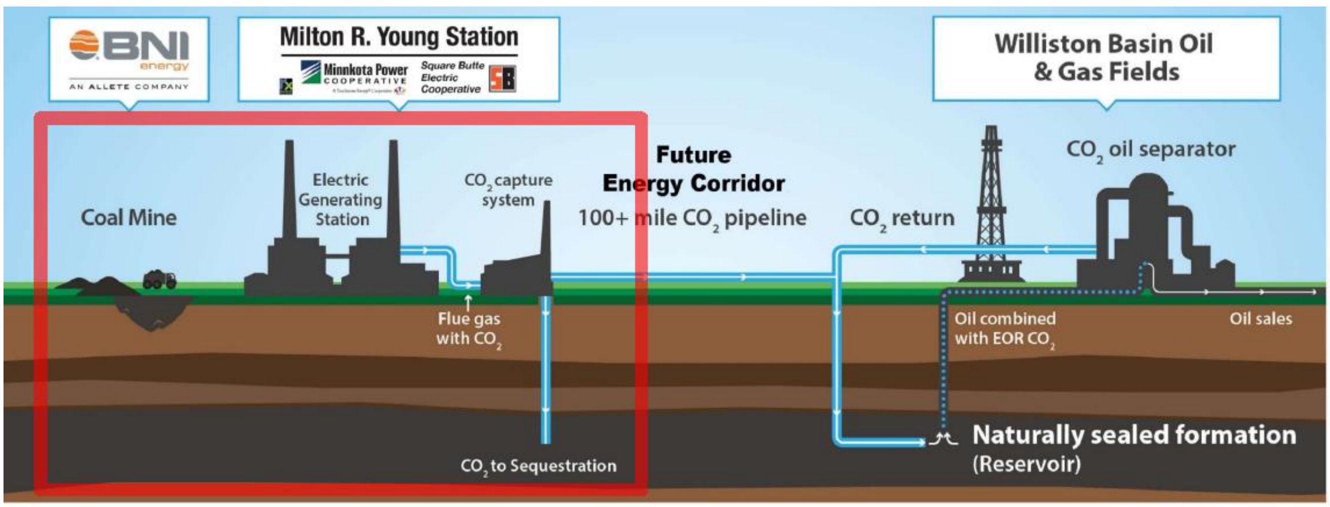

Figure 4-3. Milton R. Young Generating Station: Proximity to Sequestration Site, EOR

The Milton R. Young Unit 2 project represents a significant scale-up in process equipment size, being almost 2.5 times that of Petra Nova. The CO_2 design target of 90 percent and 11,000 tonnes-per-day removal would make this project the largest CCUS project in the world. Fluor's proprietary reagent – a formulation of primary amines evolved from prior testing – is reported to require 30 percent less steam for regeneration compared with conventional MEA.[77] Particularly challenging will be scale-up and construction of large-diameter columns and achieving good flue

[74] Pfau, G., *Front-End Engineering & Design: Project Tundra Carbon Capture System*, Project FE0031845, DOE/NETL CCUS August 2020 Review Webinar. Hereafter Pfau August 2020 Webinar.
[75] Front-End Engineering and Design: Project Tundra Carbon Capture System. Available at: https://netl.doe.gov/projects/files/FE0031845_MPCI_EFG%20FEED_tech%20sheet.pdf. Hereafter 2020 Tundra FEED Tech Sheet.
[76] Reddy, S. et. al., Fluor's Econamine FG Plus[SM] completes test program at Uniper's Wilhelmshaven coal power plant, Energy Procedia 114 (2017) 5816-5825.
[77] Ibid.

gas/liquid sorbent distribution within the packing. Fluor has constructed and fabricated similar-sized gas/liquid contact vessels in remote locations for the petrochemical industry.

Per typical practice, a pre-treatment step is utilized. The Econamine FG Plus^{SM} process employs a two-stage direct contact cooler to lower flue gas temperature and introduce sodium hydroxide reagent to further lower SO_2. It is targeting single-digit in ppm SO_2 content for optimal reagent performance. For some absorption-based projects, solvent loss – and the need for replacement – has been observed and represents a notable cost. Fluor reports to have developed a solvent maintenance program to limit sorbent loss to 0.25 kg per tonne of product CO_2.[78] The direct contact cooler also recovers condensed water from flue gas, partially offsetting make-up water requirement. The sulfur-containing effluent from the SO_2 polishing step will be managed within the plant's existing coal combustion residual complex.

The optimal use of low-grade heat, auxiliary power, and water will be explored. Means to utilize "intercooling" of solvent and compressor waste heat will be applied to lower steam consumption for regeneration by 10 to 15 percent. Absorber design to lower gas pressure drop will be explored. Auxiliary steam may be provided by a separate natural gas-fired boiler in lieu of extraction from the host unit, offering better flexibility and lower process risk. Process water captured with CO_2 will be used for cooling tower make-up water.

CO_2 will be stored in a saline formation beneath both the generating station and an adjacent lignite mine, eliminating the need for a pipeline. The project team expects that a $50/tonne Section 45Q tax credit will cover capital requirement, return on capital, and process operating costs. That would provide a return-to-tax-equity yield of almost 10 percent. Similar results would be obtained with EOR, earning market revenue from the sale of CO_2 plus a $35/tonne Section 45Q credit. The cost to avoid CO_2 emissions is expected to be $49/tonne.[79]

<u>Summary</u>. The planned Milton R. Young CCUS project would be the largest in the world on a coal-fired power plant, employing process advancements and second-generation solvents. The design explores solvents that require less energy, utilization of low-grade heat, a means to retain sorbent longevity and performance, and minimizes water consumption for flue gas pre-treatment and cooling. A key factor favoring the economics at this site is proximity of a saline reservoir for storage – beneath the station – eliminating need for an extended CO_2 pipeline. CO_2 also could be deployed for EOR, albeit requiring a 100-mile pipeline.

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[78] Ibid, page 5.
[79] 2020 Tundra FEED Tech Sheet, page 3.

4.4 Basin Electric Dry Fork Station [80,81]

Basin Electric Dry Fork Unit 1 is the host site for a FEED evaluation of the Membrane Technology and Research (MTR) CO_2 capture process. This 422 MW gross (385 MW net) PRB-fired unit located in Gillette, WY, is equipped with a dry lime fluidized bed FGD process, a fabric filter for particulate control, and combustion controls (low NOx burner with overfire air) and SCR for NOx. The process design will be based on a 20 tonne-per-day CO_2 removal pilot plant (1 MWe) that treated flue gas from a coal-fired test furnace as well as on preceding work at bench-scale (1 tonne/day) at the National Carbon Capture Center (NCCC).[82] The process design for Dry Fork Unit 1 represents significant scale-up from the most recent pilot plant.

Unit 1 gas flow will be processed with MTR's Polaris membrane CO_2 capture process, featuring low pressure drop and an optional selective recycle sweep module design. The design target of 70 percent CO_2 removal and 5,600 tonnes per day provides the least cost of avoided CO_2. MTR reports its design is distinguished by membrane composition and the use of incoming combustion air to "sweep" CO_2 from the membrane for recycle into the boiler. MTR states elevating flue gas CO_2 content lowers the cost of CO_2 removal by increasing the driving force for mass transfer.

Figure 4-4 presents a simplified schematic of the MTR capture process. Typical of most CO_2 capture processes, a pre-treatment step is used to lower flue gas temperature for effective membrane capture. MTR reports its next-generation membrane represents a considerable improvement over prior technology. It offers 10 times the ability to separate CO_2 (e.g., the permeance) of conventional membranes, thus lowering surface area and cost.

Figure 4-4 depicts MTR's selective-recycle step that purges exposed membranes and returns separated CO_2 to the boiler, lowering module cost and pressure drop. It shows flue gas entering a primary capture module that generates 55 to 60 percent CO_2 off-gas. Further processing by a second membrane elevates off-gas CO_2 content to greater than 85 percent. This enriched off-gas is treated to remove moisture, purified to 99 percent, and compressed. Higher CO_2 removal (to 90 percent) is possible with additional process steps.

The MTR membrane recovers water from flue gas for use in the plant. The Dry Fork station employs dry cooling. The FEED study will determine optimal uses for recovered water within the plant water management system.

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[80] Freeman, B. et. al., *Commercial-Scale FEED Study for MTR's Membrane CO_2 Capture Process*, Project FE0031846, DOE/NETL CCUS August 2020 Review Webinar.
[81] Commercial-Scale Front-End Engineering Design Study for Membrane Technology and Membrane Carbon Dioxide Capture Process. Available at: https://www.netl.doe.gov/projects/files/FE0031846_MTR_Polaris%20FEED_tech%20sheet.pdf.
[82] DE-FE0005795.

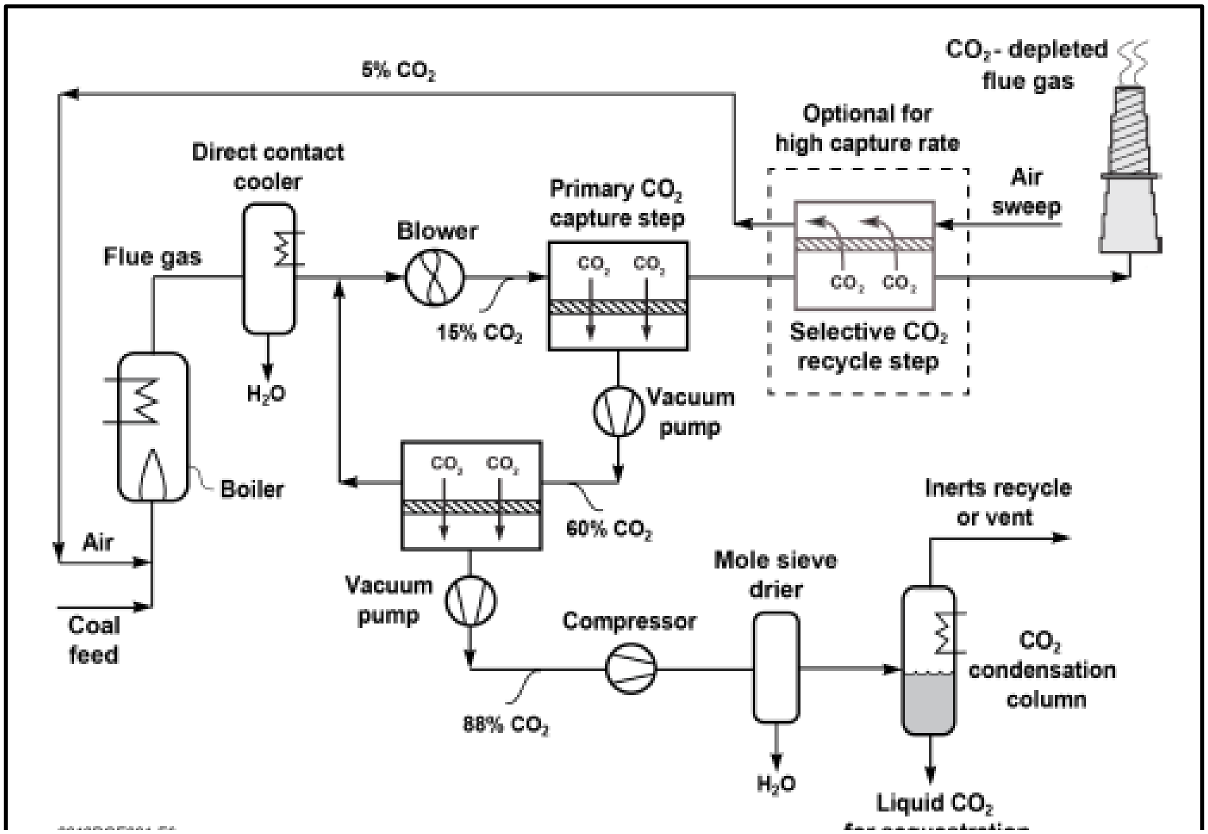

Figure 4-4. Flow Schematic: MTR Gas Separation Membrane

The FEED study results defining cost for retrofit of the MTR process to Dry Fork Unit 1 were to be reported to DOE by late 2021. A predecessor study addressing cost for MTR application to Duke Energy's East Bend Station projected a capital requirement of $1,044 M for a net unit output of 585 MW, corresponding to a unit capital cost of $2,130/kW. This predecessor study estimated the cost to avoid CO_2 to range from $75/tonne to $89/tonne.[83]

The options of CO_2 disposition will be evaluated in a separate DOE-funded activity (FE-FE0031624), as part of the Wyoming CarbonSAFE project. This work, under the management of the University of Wyoming, will consider terrestrial sequestration in Campbell County, WY, delivering a Class VI permit. Upon completion, the Campbell County site will be able to store 2.2 million tons per year (Mtpy) of CO_2.

<u>Summary</u>. The Dry Fork project employs membrane-based separation, a viable alternative to amine-reagent absorption technology. The design to be demonstrated will remove 70 percent of CO_2 to achieve the least cost capture. Design variants to achieve higher CO_2 capture are feasible. The membrane separation concept captures water from flue gas, benefiting the generating station water balance. Key to this project's success is availability of deep saline storage for modest transport distance.

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[83] *Initial Engineering Design of a Post-Combustion CO_2 Capture (PCC) System for Duke Energy's East Bend Station Using Membrane Based Technology*, Final Project Report for work performed by EPRI per DOE Agreement DE-FE0031589, Sept. 2020. Available at: https://www.osti.gov/servlets/purl/1686164.

4.5 Nebraska Public Power District/Gerald Gentleman [84,85]

The Nebraska Public Power District Gerald Gentleman Station in Sutherland, NE, is the host for a FEED evaluation of Ion Clean Energy's absorption CO_2 process. This PRB-fired station is comprised of 665 MW Unit 1 and 700 MW Unit 2. Both units are equipped with fabric filters for particulate control and low NOx burners. Compliance with SO_2 emissions is achieved with low-sulfur PRB coal in lieu of FGD. The FEED study will evaluate for Unit 2 a proprietary solvent derived from pilot plant work conducted since 2010. The most-recent pilot studies using the Ion Clean solvent were conducted in 2015. One study involved 1,116 hours of operation on a 0.5 MW test rig at the NCCC removing a total of 380 tonnes of CO_2. The other involved 2,775 hours of operation on a 12 MWe pilot plant at the Statoil Mongstad refinery treating flue gas from a natural gas-fired heat-and-power plant and a refinery. The 12 MWe pilot plant removed a total of 14,820 tonnes of CO_2 from the two sources at Statoil Mongstad.[86]

Figure 4-5 depicts the station layout, the planned CO_2 capture footprint, and a CAD projection of the capture island. A direct contact cooler lowers flue gas temperature and provides additional SO_2 removal to achieve SO_2 to single-digit ppm to extend solvent longevity.

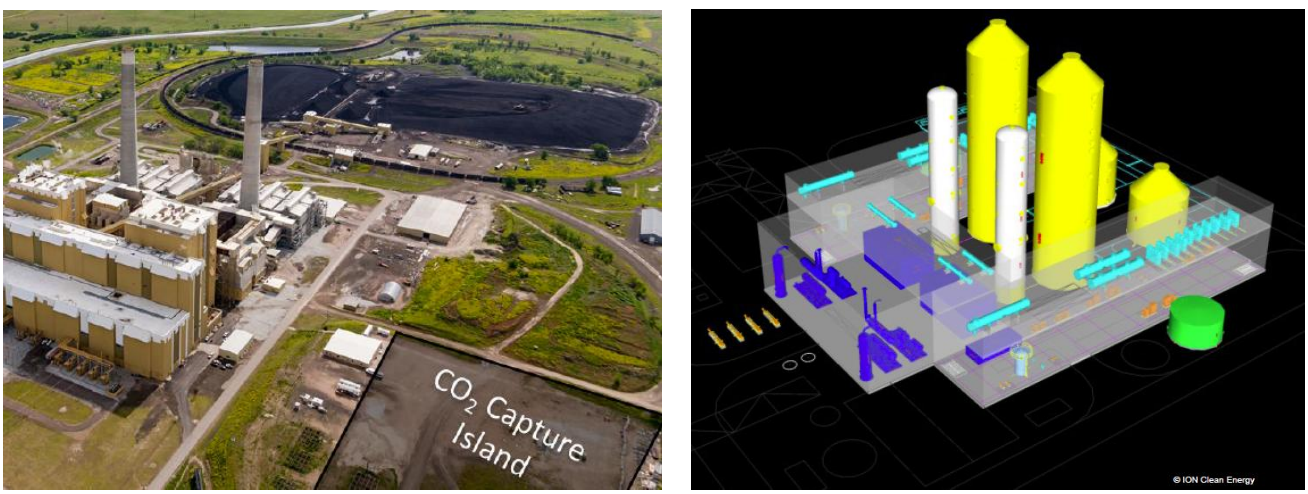

Figure 4-5. Gerald Gentleman Capture Island "Footprint" and CAD Depiction

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[84] Awtry, A. et. al., *Design and Costing of ION's CO_2 capture plant retrofitted to a 700 MW coal-fired power plant*, Project FE0031840, DOE/NETL CCUS August 2020 Review Webinar.
[85] *Commercial Carbon Capture Design and Costing: Part Two (C3DC2).* Available at: https://www.netl.doe.gov/projects/files/FE0031846_MTR_Polaris%20FEEDtech%20sheet.pdf. Hereafter Awtry DOE/NETL CCUS August 2020 Review.
[86] ION Advanced Solvent CO_2 Capture Pilot Project, Final Scientific/Technical Report, DOE-FE0013303, November 2018.

The absorber tower and stripper are solvent-based processes with several innovations implemented by Ion Clean Energy (cold-rich bypass, optimized heat exchanger for lean/rich reagent heat transfer, and a unique CO_2 compressor).

Ion Clean Energy reports its second-generation solvent features faster CO_2 absorption kinetics, higher "working capacity" and ability to absorb more CO_2, and lower heat absorption when compared with conventional amines. This contributes to a low net energy requirement of 1,090 Btu/lb CO_2. Lower corrosion rates are suggested by previous pilot plant results.

A preliminary study reports capital and operating cost are reduced because of smaller absorber columns, pumps, and heat exchangers. These benefits are attributable to lower liquid flow rates and regeneration energy because of reduced parasitic load and steam for regeneration. The preliminary cost study developed to AACE standard of a Class 3 estimate projected a capital cost of $438 M. That is equivalent to $1,460/kW and represents a reduction from the $2,454/kW as developed for the NETL/DOE reference CCUS application. The cost to avoid a tonne of CO_2 is estimated as $32.50, based on a 20-year lifetime (capacity factor not defined).[87]

The FEED study will deliver an AACE Class 2 capital cost for CO_2 removal of 90 percent and 4.3 M tonnes removed per year (at 2018-2019 capacity factors) from the 700 MW Unit 2. The process will employ water-conserving features and – unlike the strategy for other absorption applications – will employ auxiliary steam from the host boiler.

The study does not address CO_2 transport and fate. It assumes a third-party will acquire the CO_2 for EOR and incur the cost for pipeline transport.

<u>Summary</u>. Ion Clean Energy has developed a second-generation solvent for CO_2 absorption that features improved capture for lower regeneration energy, reducing both capital and operating cost. Significant scale-up is required to generalize the results from small pilot plants, a 0.5 MW equivalent on coal and a 10 MWe equivalent on natural gas and refinery gas. Experience from other projects will be available to augment the lessons from this test program.

4.6 Enchant Energy/San Juan Units 1,4[88]

Enchant Energy expects to become the owner of the San Juan Generation Station as of June 30, 2022. It is conducting a FEED study to evaluate retrofitting CCUS to Units 1 and 4. Construction is proposed to initiate prior to June 30, 2022.[89] Units 1 and 4 total 914 MW gross of capacity and fire a western bituminous coal. They are equipped with state-of-art environmental controls. These include combustion controls and SCR for NOx, fabric filters for particulate removal that are injected with halogenated activated carbon to remove Hg, and wet FGD. The station operates in zero-water discharge and will continue to do so post-CCUS.

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[87] Awtry DOE/NETL CCUS August 2020 Review. See graphic 6.

[88] Selch, J. et. al. *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station.* Project FOA-0002058, DOE/NETL CCUS August 2020 Review Webinar.

[89] Ibid. See Page 9

A preliminary study evaluating CCUS retrofit to these units was completed in 2019,[90] estimating both capital requirement and the cost of CO_2 avoided. The FEED study will evaluate the MHI absorption process and an improved version of the solvent tested at NRG's Petra Nova project.

MHI reports the three-year experience with Petra Nova led to several innovations now imbedded in the improved "KS-21" solvent. These include improved lower volatility and thermal degradation, improved resistance of oxidation, and lower heat of absorption. The process arrangement is like other absorption processes, employing a direct contact cooler to reduce gas temperature and lower SO_2 to single-digit ppm values.

The FEED study targets 95 percent CO_2 removal. This would total more than 6 M tonnes of CO_2 removed annually from the combined 914 MW generating capacity at a capacity factor of 85 percent. The design will utilize a 2 x 50 percent process arrangement for the capture island. Other aspects of this process – specifically the need to operate in zero-water discharge – will affect the design and cost basis.

The San Juan Station is favorably situated in the San Juan Basin geologic formation for direct geologic storage as well as marketing CO_2 for EOR. A pipeline of approximately 20 miles would be required to deliver compressed CO_2 to Kinder-Morgan's Cortez pipeline, which forwards CO_2 to oilfields in southeast New Mexico and the Permian Basin.

The anticipated payoff is the cumulative benefit of Section 45Q tax credits for direct geologic storage with the ability to enhance the payoff when EOR pricing is at or above $15/tonne to $20/tonne. Cumulatively, these options present a revenue stream predicated on 85 percent capacity factor and approximately 90 percent CO_2 removal that will offset much of the CCUS capital and operating cost.

Summary. The San Juan station represents a case where proximity to a suitable geologic formation and strong EOR market can enable cost-effective means to avoid CO_2 emissions. The FEED analysis will leverage experience from the NRG Petra Nova project and could identify a near-term option to retain operation of Units 1 and 4.

[90] Enchant Energy San Juan Generating Station – Units 1 & 4: CO_2 Capture Pre-Feasibility Study, Final Report, Sargent & Lundy, Project No. 13891-001, July 8, 2019.

4.7 Prairie State Generating Company[91,92]

Prairie State Generating Company is hosting a FEED study on the 816 MW (gross) Unit 2 to evaluate CCUS feasibility. The analysis will address the MHI KM-CDR process tested at NRG's Petra Nova project and to be evaluated for Enchant Energy's San Juan units, but on a high-sulfur Illinois coal.

Unit 2 features state-of-art environmental controls. These include advanced combustion controls augmented by SCR for NOx, ESPs for particulate matter control, wet FGD, and a final wet ESP particulate matter control. Mercury emissions are controlled by SCR and wet FGD "co-benefits." The features of the MHI KM-CDR process and the KS-21 sorbent have been described previously for San Juan.

Figure 4-6 presents a satellite image of the PSGS site, depicting where process equipment will be located. As of August 2021, minimal details of the study were available.

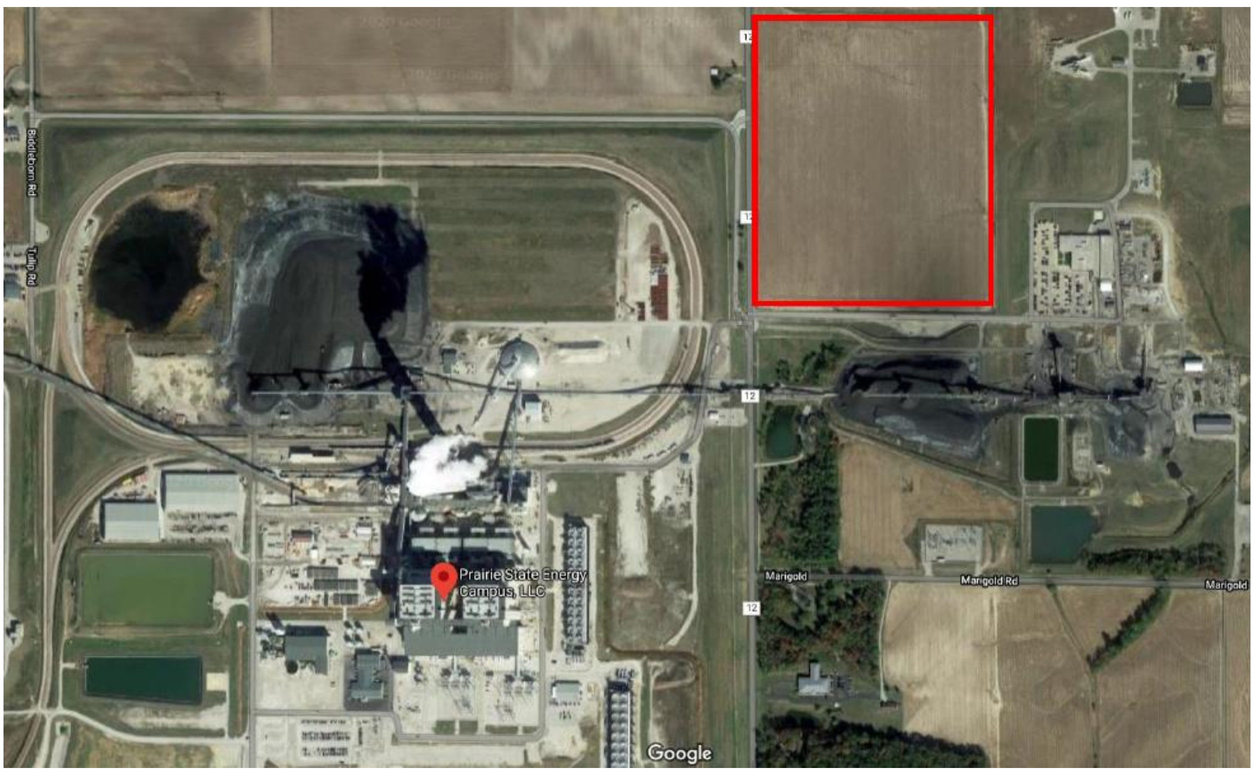

Figure 4-6. Prairie State Generating Station Unit 2 with Footprint for CO_2 Capture Island

[91] O'Brien, K. et. al., *Full-Scale FEED Study For an 816 MWe Capture Plant at the Prairie State Generating Company Using Mitsubishi Heavy Industries of America Technology*, Project FOA-0002058, DOE/NETL CCUS August 2020 Review Webinar.

[92] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, available at: https://netl.doe.gov/projects/files/FE0031841_UIL%20FEED_tech%20sheet.pdf.

The fate of the CO_2 will be determined by integrating this work with the CarbonSAFE project addressing CO_2 sequestration or sale for EOR in Illinois.

Summary. Prairie State Generating Company is developing a next-generation design of the MHI KM-CDR process, leveraging design lessons from Petra Nova. The fate of CO_2 captured will be determined working with the CarbonSAFE project in Illinois.

4.8 SaskPower Shand Unit 1 [93,94]

SaskPower Shand Unit 1 features a generating output of 305 MW gross (278.5 MW net) and is located 12 km from the Boundary Dam site. The unit fires a western bituminous coal from a nearby mine and is equipped with combustion controls for NOx and an ESP for particulate matter control. The unit initially was equipped with furnace dry limestone injection for FGD, with SO_2 removal augmented by Re-Activation of Calcium (LIFAC) system. The FGD components are de-activated due to reliability problems. Zero-water discharge is required.

A preliminary engineering study evaluating CCUS at Shand exploiting “lessons learned” from Boundary Dam Unit 3 was completed in 2019.[95] The Shand analysis evaluated application of the MHI KM-CDR absorption process tested at Petra Nova. The study included retrofit of wet limestone FGD for SO_2 compliance and to maintain solvent effectiveness. Figure 4-7 depicts the retrofit of process equipment and identifies the scope of work of the CO_2 process supplier.

The FEED study targets approximately 90 percent CO_2 removal, totaling 6,540 tonne per day, and is projected to operate at an annual capacity factor of 85 percent. The design will utilize a 2 x 50 percent equipment arrangement for the capture island.

As with all absorption processes, considerable effort is devoted to low-grade heat utilization and strategies to minimize auxiliary power and heat consumption. This includes using flue gas waste heat for steam turbine condensate preheating and condensate energy for feedwater preheating. It also includes removing a feedwater heater from service during CCUS operation to minimize the penalty of the auxiliary steam consumption. Cumulatively, these and other design features are predicted to limit parasitic load to 22.2 percent of gross output.

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[93] Shand 2018 Feasibility Report.

[94] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower’s Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.

[95] Shand 2018 Feasibility Report.

Figure 4-7. 3D Depiction of Shand Unit 1 Equipped with CCUS Process Equipment

The planned fate of CO_2 derived from Shand is like Boundary Dam Unit 3. In this case, it would be for use as EOR at the Weyburn and Midale oil fields. There also are more than 30 additional fields in the region. A common carrier "hub" approach will be evaluated to route CO_2 to one or more of these oil fields.

SaskPower reports investment cost for the total of life extension actions, incremental power output, and CCUS. This cost including all preceding actions (2024 escalation) is $986.4 M, equivalent to $2,121/kW. This capital estimate and projected operating costs infer the cost to avoid a tonne of CO_2 of approximately $45. That is based on an 85 percent capacity factor, 30-year capital recovery period, and 90 percent CO_2 removal. The largest components of this cost are capital ($22/tonne), foregone electricity revenue ($14/tonne), operations and consumables ($7/tonne), and limestone for incremental SO_2 removal ($2/tonne). SaskPower notes the cost is 62 percent less than that incurred for Boundary Dam Unit 3. These costs reflect a first-of-a-kind installation and not representative of costs anticipated after several large-scale applications. SaskPower does not offer a capital investment for CCUS separate from that including life extension and thermal performance improvements.

<ins>Summary</ins>. The Shand study exploits lessons learned from both Boundary Dam 3 and Petra Nova. The significant reduction in capital cost translates into a 62 percent reduction in levelized cost per tonne of CO_2 avoided. Capital cost for CCUS separate from life extension or thermal performance improvements is not available. This study clarifies the types of process and heat integration improvements that are feasible to lower both capital and operating cost.

4.9 DOE/NETL Reference Case [96]

The DOE/NETL reference case is a subcritical boiler generating 650 MW (net) output, based on gross generation of 776 MW. The auxiliary power demand of 126 MW is comprised of 46.6 MW for CO_2 compression, 28.7 MW from CO_2 capture and removal, and 50.8 MW attributable to conventional plant activities. The hypothetical unit is equipped with combustion controls and SCR for control of NOx, a fabric filter for particulate matter control, wet limestone FGD process, and a combination of sorbent injection and "co-benefits" for Hg control. These technologies provide state-of-art control – 98 percent SO_2 removal, 99.9+ percent particulate removal, NOx emission to less than 0.07 lbs/MBtu, and greater than 90 percent Hg control to meet the mandate of 1.2 lbs/TBtu. Figure 4-8 reproduces the block flow diagram reporting the mass and energy balance used to specify components and process equipment and determine CCUS installed cost.

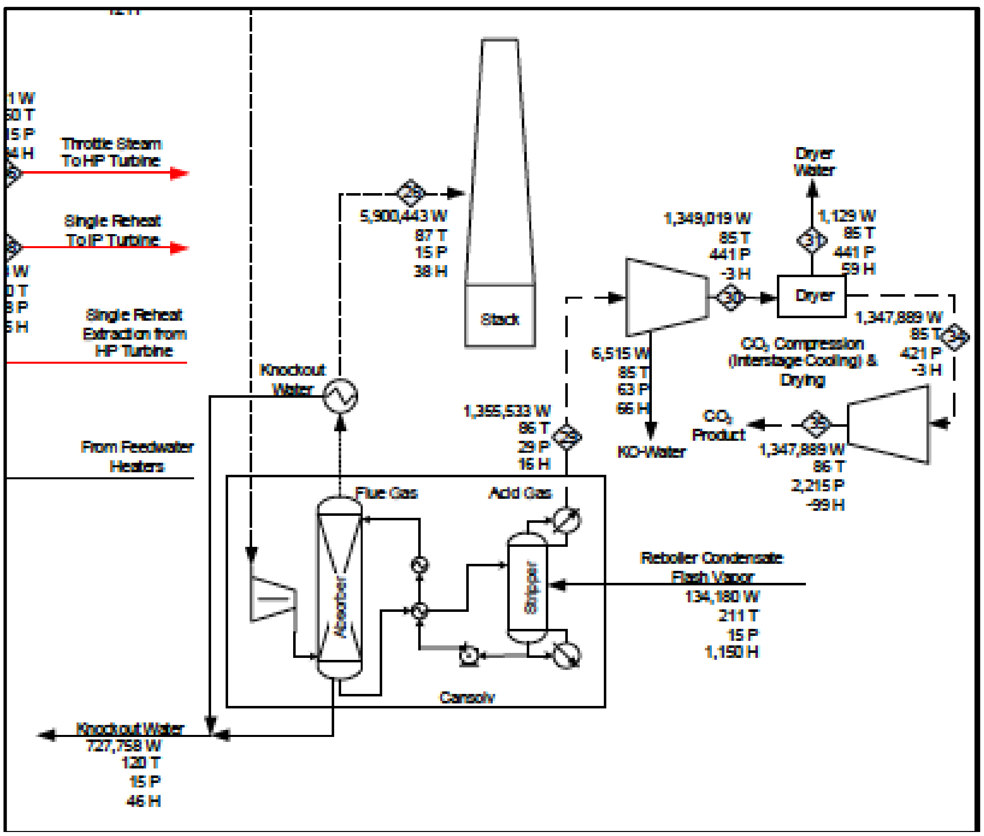

Figure 4-8. Flow Diagram: Cansolv CCUS to 650 $MW_{(n)}$ Subcritical Pulverized Coal Unit

The analysis assumes CO_2 is sequestered off-site in a saline reservoir. The pipeline, sequestration site characterization and monitoring along with construction and operation of the Class VI injection wells are included in an assumed cost of \$3.5/MWh. Figures 4-9 and 4-10 (reproduced from the DOE/NETL report) present results comparing capital and LCOE for the baseline subcritical PC unit. They are shown with and without CCUS and that equipped with CCUS. Also shown on both figures (but not discussed in this report) are analogous results for a supercritical PC unit employing a similar process design.

[96] NETL Bituminous and NGCC 2019 Reference Study.

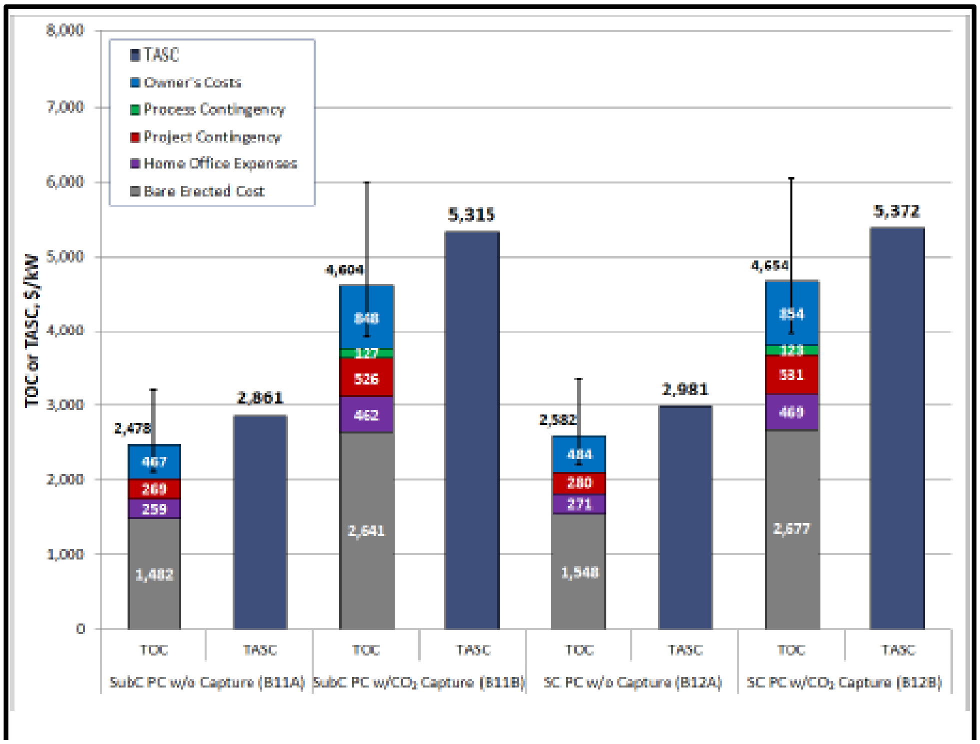

Figure 4-9. Capital Cost for DOE/NETL Reference Subcritical and Supercritical PC Study

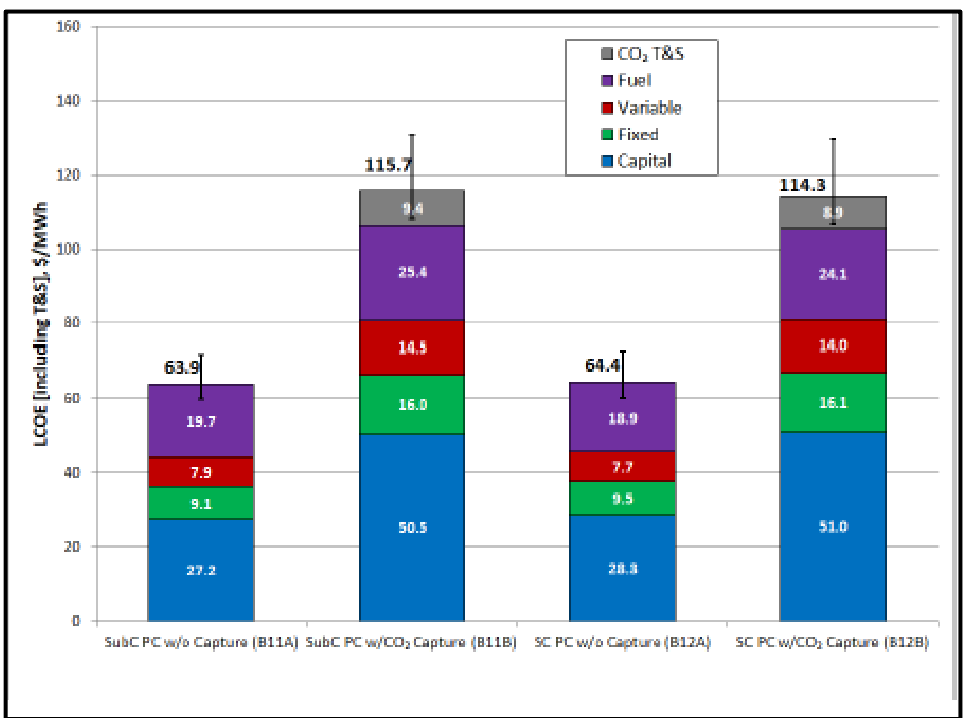

Figure 4-10. Levelized Cost for DOE/NETL Reference Subcritical, Supercritical PC Study

As defined in Section 3 for NGCC application, *Bare Erected Cost* includes process equipment, support facilities and infrastructure, and direct and indirect labor for construction. It does not include engineering and procurement and contingencies. The *Total Plant Cost* includes engineering/procurement and contingencies. The *Total Overnight Costs* reflects the Total Plant Cost but includes Owners Costs reported under the conditions of "overnight" installation. Finally, the *Total As-Spent Capital* reports all costs – including any escalation over the construction period – and financing charges. This is the key metric of evaluation.

Also presented is the Levelized Cost of Electricity. This is based on 85 percent capacity factor, 30-year operating lifetime, and financing charges that reflect typical utility conditions.

DOE/NETL's cost evaluation shows for a conventional absorption process applied to a subcritical PC boiler the capital cost (as Total As-Spent Capital) presents an 81 percent cost premium, adding approximately $2,454/kW. The LCOE reflecting the CCUS-equipped option is $115.7/MWh, exceeding the Baseline Case (without CCUS) by $51.8/MWh. The largest component of levelized cost is additional fuel to support CCUS, followed by capital.

The cost to avoid CO_2 for the conditions adopted in Figure 4-10 that determine the levelized cost of electricity is approximately $70/tonne. This includes the transportation and storage cost. If the captured CO_2 can be sold at the plant boundary for EOR, and the cost for transport is adopted by the buyer, the avoided cost of $55/tonne represents a market "breakeven" price that covers the cost of process equipment.

4.10 Observations: Potential CCUS Application to Coal

The following observations are offered for pulverized coal-fired CCUS application based on the two ongoing or completed projects and six FEED studies in progress:

- The use of absorption processes with amine-based solvents is the predominant control technology at present. Early versions of this process at Boundary Dam Unit 3 and Petra Nova employed solvents that – although effective – require significant energy for regeneration, can induce corrosion, and can be compromised by residual gas constituents. The proposed projects use improved, next-generation version of these solvents. MHI exploited Petra Nova results to improve their CDR solvent. Fluor continues to evolve the solvent for the Econamine process. Ion Clean Energy and the University of Texas at Austin each have formulated improved solvents. Further refinement of these solvents will lower both capital and operating costs.

- Alternatives to absorption processes are progressing, as demonstrated by the MTR Polaris membrane technology. The Dry Fork project will improve process understanding of this alternative, lowering costs and increasing process feasibility.

- Each of these sites – particularly Minnkota, Dry Fork, Gerald Gentleman and San Juan – benefit by proximity to oil fields or major pipelines. This promotes the prospect of EOR revenues that can offset costs without a major pipeline investment.

- Capital cost reduction is necessary to broaden CCUS applicability. For absorption processes, lower cost can be achieved with evolving solvents offering fast kinetics for CO_2 capture and lower heat for regeneration. Both capital and operating cost can be reduced.

Section 4 suggests that given reductions in capital and operating cost achievable by process improvements and favorable site features, CCUS can be a viable option. Additional cost studies and large-scale tests that improve reliability and identify means to minimize capital and operating costs are required to achieve these goals.

5 Evolving CO_2 Capture Technologies

5.1 Background

CO_2 capture technology is not static. The projects described in Sections 3 and 4 address options evolved from pilot plant tests conducted over decades. Capture technology for CO_2 will evolve, as did control technologies for SO_2, NOx, and particulate matter over the last 50 years. The continual improvement in process technology – and anticipated reduction in capital and operating cost – is a result of an ordered sequence of laboratory exploration, pilot plant tests, and large-scale projects.

Section 5 of this paper describes CO_2 capture technologies based on absorption, adsorption, membrane and cryogenic processes with prospects for large-scale application in the next five to 10 years. Section 5 also treats the evolving Allam-Fetvedt Cycle for new “greenfield” power, which applied to natural gas or renewable gas-firing is under development by NET Power.

A detailed treatment of emerging CO_2 capture technologies is beyond the scope of this discussion. Such an authoritative treatment is presented in the 2018 multi-volume review prepared by the American Petroleum Council (APC). Appendix E focuses on amine-based technologies derived from natural gas processing and Appendix F treats evolving technologies with long-term (> 10 year) payoff.[97] In addition, the DOE/NETL has published a compendium of projects funded to address evolving CO_2 capture technologies.[98] These evolving processes share the same objective of ultimately achieving efficient, low-cost CO_2 removal from fossil fuel power stations.

5.2 Development Strategy

As described in Section 2, a wide range of test facilities is employed for process development. The sequence of equipment and testing is generally categorized as the following:

- Bench-scale reactors that employ “synthetic” flue gas created to simulate certain aspects of application. The test duration for this class of experiments is short, typically hours.

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[97] Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, 2019, National Petroleum Council. Available at: https://dualchallenge.npc.org/. Hereafter NPC Report. Hereafter National Petroleum Council 2019 Report. See Appendix F, Table F-1.

[98] DOE/NETL CAPTURE PROGRAM R&D: Compendium of Carbon Capture Technology, April 2018. Hereafter DOE/NETL Carbon Capture R&D April 2018 Compendium. Available at: https://www.netl.doe.gov/sites/default/files/netl-file/Carbon-Capture-Technology-Compendium-2018.pdf.

- Small- and large-scale pilot plants that are in dedicated test facilities or within a power station and extract a "slipstream" of flue gas for testing. The flowrate of gas tested can be 10 to 100 times the size of bench- or laboratory-scale equipment, with test durations measured in days to weeks and months. Flue gas reflects authentic composition, but the limited scale can distort results due to unrepresentative mixing, gas temperature distribution, or reactor geometry (e.g., surface-to-volume ratio).

- Large-scale equipment in which gas flowrate replicates a small power plant, typically with 100 MW as a minimum.

The refinement of control technologies for FGD, NOx, particulate matter, and mercury was accomplished at federal government and electric power industry pilot plant facilities located at "host" power stations. Among the most notable examples are the EPA Shawnee Prototype Lime/Limestone Test Facility at TVA's Shawnee Generating Station, EPRI's Arapahoe Test Facility in Denver, CO, and High Sulfur Test Facility in Somerset, NY, and the Mercury Research Center at Gulf Power's Plant Crist. They have provided stable, authentic test beds from the mid-1970s through the present day. Bench-scale and pilot plant tests directed to CO_2 capture are presently being conducted at the National Carbon Capture Center (NCCC) (Wilsonville, AL). The Wyoming Integrated Test Center will also host the Membrane Technology and Research (MTR) large pilot project.

There have been about 75 participants in DOE-funded development programs. Select examples are:

- Academia: universities of Kentucky, Illinois, Notre Dame, North Dakota, Akron, and others.

- Corporate industrial facilities: GE Global Research, Siemens Energy Group, Linde, Babcock & Wilcox, URS Group, SRI International, RTI International, and others.

- U.S. national government laboratories: Argonne, Lawrence Berkeley, and Pacific Northwest.

- Specialty research entities: Ion Clean Energy, Neuman Systems, TDA Research, Inc., MTR, Inspira LLC, and others.

The NCCC in the U.S. and the Technology Center Mongstad (TCM) located adjacent to the Equinor Mongstad Refinery[99] are active in the present development programs.

The sequence of development steps is exemplified by that pursued for the "chilled ammonia" process.[100] This early CO_2 capture process, envisioned at a laboratory "bench" scale in 2006,

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[99] Technology Mogstad Center, DOE/NETL 2020.
[100] Di Federico, G., Baker Hughes – Towards Net Zero Carbon Emissions. DOE/NETL CCUS August 2020 Review Webinar.

evolved in steps to a 20 megawatts thermal (MW_{th}) pilot plant operated by American Electric Power (AEP) from 2007 to 2011. Additional tests employed a 0.25 MW_{th} pilot plant in Sweden (2012) and two 5 MW_{th} pilot plant test programs in the U.S at the Pleasant Prairie Station and in Germany on E. On's oil-fired Karlsrhue station (2009-2011). This experience, augmented by a 40 MW_{th} large pilot plant at a combined heat and power facility in Norway (2000-2010), provided the basis for a FEED study to evaluate a 235 MW test project at AEP's Mountaineer station. The results of these bench, pilot, and large-scale facilities showed the chilled ammonia process to be a technically feasible option but it required prohibitive costs in the context of 2011.[101] This cost context now is being revisited by Baker-Hughes, which has explored applications – including those to NGCC generation facilities – since 2013.

5.3 Process Categories

Section 2 overviewed four categories of CO_2 removal processes: absorption, adsorption, membranes, and cryogenic. As noted, all categories could contribute feasible CO_2 capture processes equally applicable to NGCC and coal-fired flue gas.

5.3.1 Absorption/Second Generation Reagents

The attributes of a second-generation CO_2 solvent that can lower capital and operating cost are the following: fast reaction kinetics to reduce the absorber volume, increased CO_2 carrying capacity reducing solvent required, less energy to liberate CO_2 from the solvent, and improved resistance to degradation.

Four second-generation solvents are candidates for evaluation in the projects described in Sections 3 and 4. MHI builds upon the Petra Nova experience to refine the solvent planned for Prairie State Generating Company Unit 2 (KD-21). BASF is refining the BASF OASE® blue solvent to be evaluated in the Plant Daniel Unit 4 FEED study. The piperazine solvent developed by the University of Texas at Austin is planned for testing at the Golden Spread station. And Ion Clean Energy is demonstrating its solvent at Nebraska Public Power District/Gerald Gentleman Station. The BASF OASE® blue solvent will be optimized in pilot plant tests planned for the City Water Light & Power (CWL&P) Dallman Unit 4 (Springfield, IL). This 10 MW pilot plant depicted in Figure 5-1 will explore solvent composition to improve CO_2 capture at low circulation rate and improve stability.[102]

The pilot plant features offer an innovative interstage heat exchanger to reduce steam consumption for CO_2 regeneration. A preliminary cost evaluation for a CCUS process exploiting both process and solvent improvements suggests the cost per tonne of CO_2 avoided of $41 to $44/tonne.

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[101] Tamms, K. et. al., CCS Business Case Report, December 20, 2011. Available at: www.globalccsinstitute.com/publications/aep-mountaineer-ccs-business-case-report.

[102] K.C. Obrien, Large Pilot Testing of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Coal-Fired Power Plant (FE-0031581), DOE/NETL CCUS August 2020 Review Webinar.

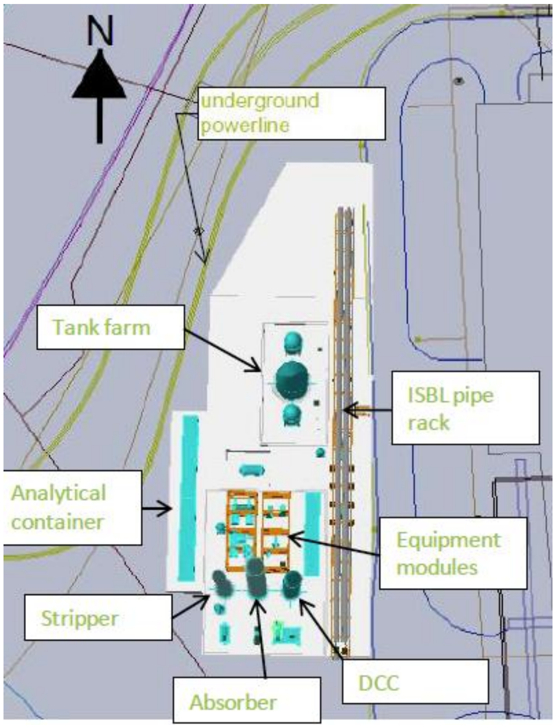

Figure 5-1. Plot Plan of CWLP Second Generation Absorbent Pilot Plant

Tests to further advance absorption solvents are underway. DOE/NETL alone is funding 25 such projects.[103] In October 2021, DOE announced an award to SRI International to improve SRI's mixed salt absorption modules to elevate regeneration efficiency for 95 percent of CO_2 from NGCC flue gas.[104] The solvents under development include non- or low-aqueous sorbents, improved amine-based compounds, and various ionic-based solvents. Select examples are:

- A Dual-Loop Solution-based process that is being explored by a team led by the University of Kentucky to lower equipment cost by 50 percent. It is targeted to NGCC flue gas with a 95 percent CO_2 capture efficiency.

- Non-aqueous based solvents by RTI International that are based on tests conducted in 2018 at the NCCC and a second (designated as GAP-1) by GE Global. Both were at the NCCC in 2016 and 2017. A multi-component, water lean solvent also is being explored by Fluor.

- Amino silicone solvents by GE Global Research and self-concentrating amines by 3H Company, LLC.

[103] National Petroleum Council 2019 Report. Appendix F, Table F-1.
[104] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

- Reversible ionic liquids by the Georgia Tech Research Corporation and ionic liquids by the University of Notre Dame.

Further discussion of absorbent process and solvent development is in Appendix F of the APC evaluation.[105]

5.3.2 Solid Adsorbents

Solid adsorbents physically bind CO_2 to the surface of a solid carrier, distinguishing them from liquid or water-based absorbents. Solid adsorbents typically require engineered material and thus entail considerable time and investment for payoff. Analogous to absorption processes, a key challenge is liberating the CO_2 from the carrier. To this end, pressure swing and temperature swing regenerations steps are being explored.

More than one dozen materials have been explored by some of the organizations involved in developing absorption processes. Several examples are:

- A monolithic amine contactor to capture the $CO_{2,}$ followed by steam-driven thermal desorption and CO_2 collection. Cormetech is developing this process with DOE funds awarded in October 2021. It includes a multi-bed cyclic process unit without the need for vacuum for desorption supporting scalability to NGCC plants.[106]

- Thermal swing adsorption process, under development at laboratory scale by a partnership between TSA Research, and Membrane Technology and Research (MTR). It employs adsorption sheets that capture CO_2 and are regenerated in a microwave heater.[107] The anticipated improvement is reduced time between adsorption and desorption cycles for CO_2 regeneration.

- Dry carbonates, in particular the reaction of sodium carbonate with CO_2 to bicarbonate by RTI International.

- Metal monolith compounds integrated with amine-grafted silica by the University of Akron.

- Polymer-supported amine compounds configured with composite hollow fibers for use in a rapid temperature swing reactor by Georgia Tech Research Corporation.

- Alumina-based sorbents in a fixed bed reactor with steam regeneration by TDA Research.

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[105] National Petroleum Council 2019 Report. Appendix F, Table F-2.
[106] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.
[107] Ibid.

- A rotary regenerative wheel featuring diamine-functional silica gel is envisioned by Inventys VeloxoTherm. A conceptual design of a 10 MW pilot plant is being developed in partnership with NRG Energy.[108]

Metal organic frameworks (MOFs) are receiving significant research interest. These specially structured crystalline compounds feature adsorption properties that can be tailored for specific applications. MOFs are being integrated with zeolite and activated carbon to maximize adsorption properties. Notably, DOE announced in October 2021 the funding of GE Research to develop an integrated system of contacting vessels and MOF sorbents to capture 95 percent of CO_2 from NGCC flue gas.[109] These compounds are being evaluated for possible commercialization through university spinoffs such as NuMat Technologies and Mosaic Materials. Svante (formerly known as Inventys) is adopting similar compounds into a rotating temperature swing adsorption process.[110]

5.3.3 Membranes

Membranes are semi-permeable materials that selectively separate CO_2 from background gases. Membranes use gas pressure as a driving force for separation. That makes them well-suited to applications where the pressure of the gas treated is relatively high but are applicable to combustion products at atmospheric pressure.

The MTR Polaris membrane to be demonstrated at Dry Fork Unit 1 evolved from tests in 2014 at the NCCC. The present project is supported by continued work to improve the MTR membrane and the contacting reactor. DOE/NETL is funding additional membrane CO_2 separation technology,[111] examples of which include:

- Low-temperature “cold” membranes seeking a factor of 10 increase in permeance compared to conventional materials are being evaluated by Air Liquide at the NCCC.

- A hollow fiber gas-liquid membrane contacting reactor directed to improve CO_2 adsorption compared to conventional packed beds is explored by the Gas Technology Institute (GTI). GTI is also developing membranes composed of graphene oxide.

- Fundamental research with long-term but potentially high payoff is being conducted in academic environments. Ohio State University is exploring a two-stage capture CO_2 process using synthetic polymers and the University at Buffalo is addressing mixed-matrix materials that are comprised of soluble metal-organic polyhedral compounds.

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[108] DOE/NETL Carbon Capture R&D April 2018 Compendium, page 372.
[109] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.
[110] DOE/NETL Carbon Capture R&D April 2018 Compendium, page 372.
[111] Ibid.

These example projects are being executed at small pilot or bench-scale and likely will require five to 10 years of refinement and large pilot test projects. However, they could significantly lower the cost of CO_2 capture.

5.3.4 Cryogenic

Cryogenic processes have been used for decades to separate CO_2 from natural gas and could provide a viable means for CO_2 removal from combustion products.

Sustainable Energy Solutions (SES) is developing a cryogenic process that employs phase change to separate CO_2 from the gas stream. The SES process has been tested at bench and small pilot scale. It requires lowering gas temperature to -140ºC, thus prompting CO_2 to "de-sublimate" or convert to solid phase. After solidifying and separation, the CO_2 is pressurized and liquefies in preparation for pipeline delivery.

This process has been tested at small pilot plant scale at a PacifiCorp power station, a cement processing plant, and a Brigham Young University facilities plant. DOE awarded SES funds in October 2021 to design and operate an engineering-scale Cryogenic Carbon Capture™ process at the Eagle Materials/Central Plains Cement Sugar Creek Cement Plant in Sugar Creek, MO. The project will seek to remove nominally 30 tonnes of CO_2 per day and demonstrate more than a 95 percent CO_2 removal rate.[112]

A second approach, called the Supersonic Inertia CO_2 Extraction System, is being pursued by Orbital ATK Inc. It is an inertial carbon extraction system, expanding flue gas through a nozzle and employing a cyclone to separate solids from the gas. This concept has been tested only at bench scale to date.

Cryogenic options – although not near-term and confronted with engineering challenges – comprise another long-term solution to separate CO_2 at low cost.

5.4 Allam-Fetvedt Power Cycle

One option exclusively applicable to new "greenfield" generation is the Allam-Fetvedt Power Cycle. The process, which some have described as a specialized Brayton cycle, employs oxy-combustion and uniquely utilizes CO_2 as the working media. The result is a power generation cycle that produces exclusively CO_2 with no other constituents.

Both coal-fired and natural gas-fired applications are being developed.

Figure 5-2 presents a simplified depiction of the Allam-Fetvedt Power cycle using natural gas, as developed by Net Power. The cycle is distinguished by utilizing high-temperature, high-pressure CO_2 in the "supercritical" state as the working medium.

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[112] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

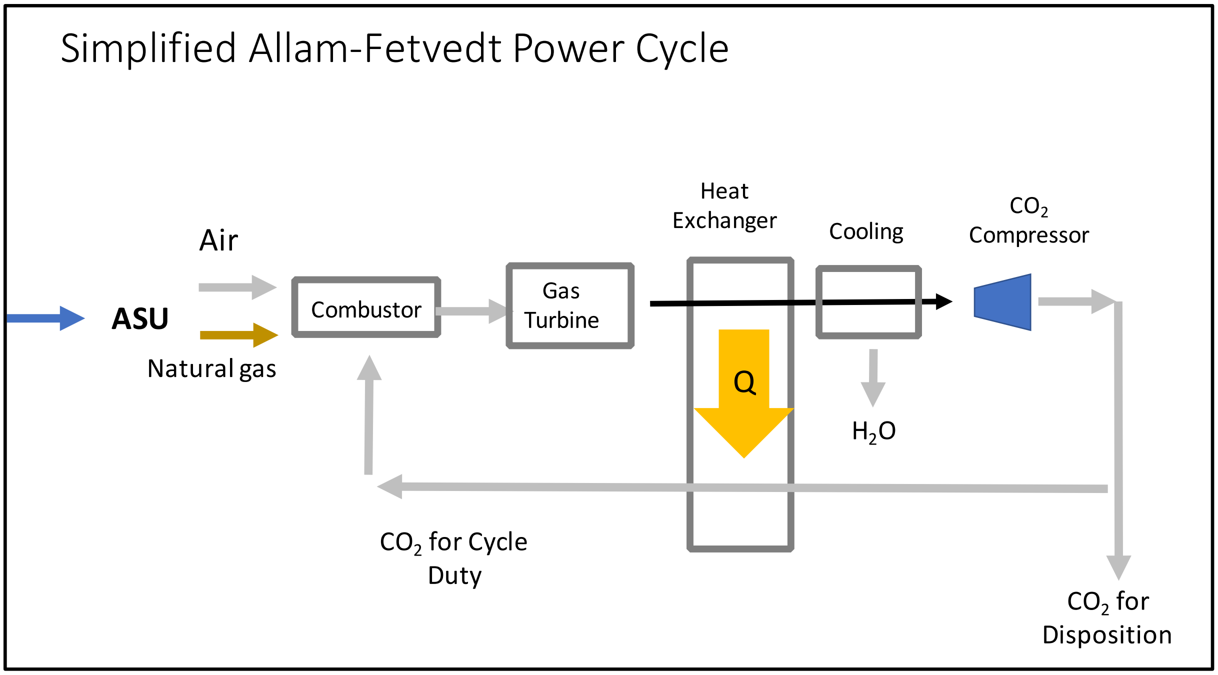

Figure 5-2. Simplified Allam-Fetvedt Cycle [113]

The cycle initiates by processing air in an air separation unit (ASU), generating pure oxygen to fire with fuel (natural gas or coal) in a combustor for which the working media is CO_2. The high-pressure, high-temperature CO_2 and water generated from the combustion process expands in a special-purpose turbine, delivering shaft work. The CO_2 effluent from the turbine enters a heat exchanger that removes or "recuperates" heat to use again in the cycle. The CO_2 and water exiting the heat exchanger are further cooled (using a cooling tower) with condensing water removed. A substantial portion of the CO_2 (approximately 8 percent) is removed to compensate for CO_2 added from natural gas combustion, which is then processed for EOR or sequestered. The remaining CO_2 is returned to the cycle, passing through the heat exchanger to acquire heat before returning to the combustor.

The Allam-Fetvedt cycle for coal-fired duty is estimated to require "overnight" capital of $3,647/kW and generate power at a net thermal efficiency cited to range from approximately 40 percent[114] to up to "the mid-to-high 40s."[115] For natural gas fuel, the thermal efficiency is claimed to approach 60 percent.[116]

To achieve these targets for thermal efficiency, turbine inlet temperature and pressures exceed that typical of commercial practice. An inlet temperature of at least 800ºC and pressure of 80 bar

[113] Figure 4-2 based on graphics deck per Espinoza 2019.
[114] Goff, A. et. al., Allam Cycle Zero Emission of Coal Power, Pre-FEED Final Report. Available at: https://netl.doe.gov/coal/tpg/coalfirst/DirectSupercriticalCO2.
[115] 300-MW Natural Gas Allam Cycle Power Plant Targeted for 2022. Power Magazine, April 15, 2019. Available at: https://www.powermag.com/300-mw-natural-gas-allam-cycle-power-plant-targeted-for-2022/.
[116] https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.

are required.[117] Consequently, a key factor in the evolution of this concept is providing an expansion turbine and ancillary components with the proper metallurgy to sustain such temperatures and pressures.

Significant federal and private funds are directed to demonstrating a natural gas-fired power station based on this concept.[118] The process developers report two generating units totaling 560 MW are planned for southwest Colorado and Illinois for operation by approximately 2025.

5.5 Evolving CO_2 Capture Technology Takeaways

- Four categories of CO_2 capture technologies are defined, each potentially contributing over the long term to low-cost CO_2 capture. Each is each equally applicable to natural gas- and coal-fired flue gas.

- The preponderance of absorption processes with amine-based solvents in this early stage of development is a consequence of experience with amine-based solvents to remove CO_2 from natural gas. It also may be because of electric power industry experience with absorption towers for FGD.

- DOE/NETL is funding approximately 75 evolving processes within the four categories to achieve the target CO_2 cost of $30/tonne. A structured development program consisting of bench-scale, pilot plant, and large-scale projects like what the electric power industry did in evolving state-of-art controls for particulate matter, SO_2, and NOx could generate lower cost and reliable CO_2 capture options.

[117] 8 Rivers Unveils 560 MW of Allam Cycle Gas-Fired Projects for Colorado, Illinois. Power Magazine, April 15, 2021. Available at: https://www.powermag.com/8-rivers-unveils-560-mw-of-allam-cycle-gas-fired-projects-for-colorado-illinois/.
[118] Ibid.

6 CO_2 Pipeline Networks

6.1 Background

Pipeline transport is the principal means by which CO_2 is and will continue to be distributed for EOR or deep saline geologic injection. There is extensive experience using high-pressure pipelines to distribute CO_2 in the U.S. dating back to the 140-mile Canyon Reef Carriers Pipeline in West Texas in 1972.[119] Since then, the cumulative length of CO_2 pipelines in the U.S. has expanded to approximately 5,500 miles.[120] Most of the pipelines provide "point-to-point" duty, connecting a single CO_2 source to a single sink. More than 90 percent of this pipeline infrastructure serves EOR. This pipeline inventory transported more than 3.5 billion cubic feet of CO_2 each day in 2019, with most source-to-sink routes employing more than one pipeline.[121]

A significant expansion of the existing pipeline network is projected to be necessary to support the projected needs for decarbonization, according to analysis by NETL,[122] the petroleum industry,[123] the Great Plains Institute (GPI),[124] and the Princeton Net-Zero America study.[125] Most notably, the GPI estimates that ultimately almost 60,000 miles of CO_2 pipeline will be required, split between "near and mid-term" and "midcentury" duty, while the Princeton Net-Zero America study projects almost 70,000 miles by 2050. The near and mid-term applications supporting both industrial and utility power generation sources would transport 281 M tonnes of CO_2 annually and require investment for capital and labor of \$30.9 B. The mid-century applications would transport 669 M tonnes of CO_2 annually and require investment of capital and labor of \$44.6 B. This additional pipeline capacity, although significant, is modest compared

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[119] CO_2 Transportation –Is it Safe and Reliable?, CLS Forum White Paper, September 2011, available at: https://www.cslforum.org/cslf/sites/default/files/documents/CSLF_inFocus_
https://www.cslforum.org/cslf/sites/default/files/documents/CSLF_inFocus_CO2Transportation.pdf.

[120] Grant, T., An Overview of the CO_2 Pipeline Infrastructure, DOE/NETL Workshop Representing Carbon Capture Utilization and Storage, College Park, Maryland, October 17-19, 2018. Hereafter Grant 2018 DOE/NETL Workshop.

[121] APC 2019 Report, Chapter 6.

[122] DOE/NETL 2015 Pipeline study.

[123] V. Kuuskraa et al, CO_2-EOR Set for Growth as CO_2 Supplies Emerge, Oil & Gas Journal, April 7, 2014.

[124] Near and mid-term applications exploit low-cost CO_2 sources in the Midwest such as ethanol facilities to deliver to Kansas, Oklahoma, and Texas. Saline injection cost is less than \$10/tonne and oil is priced at \$40/barrel. Mid-century applications heavily rely upon on Section 45Q incentives, incur saline injection costs of less than \$5/tonne, with oil priced at \$60/barrel. See Abramson, E. et. al., Transport Infrastructure for Carbon Capture and Storage, Great Plains Institute, June 2020.

[125] DOE/NETL 2015 Pipeline Infrastructure Study.

with the 535,000 miles of pipeline for natural gas and hazardous liquid transmission operating in the U.S. today.[126]

Figure 6-1 depicts the routing of major CO_2 pipelines in the U.S. and identifies locations of milestone projects that are sources or sinks for CO_2. The major regions are the Northern Rockies, Permian Basin, Mid-Continent, and Gulf Coast.

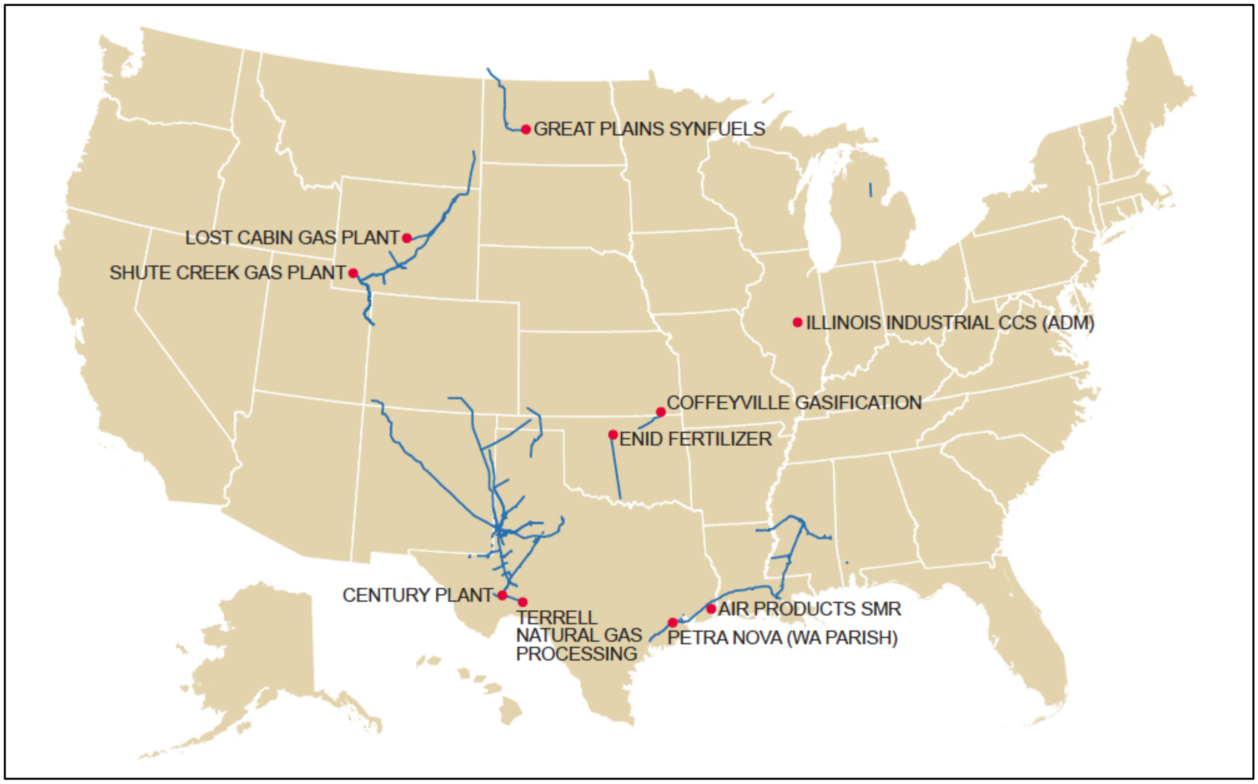

Figure 6-1. Routing of Major CO_2 Pipelines in U.S.[127]

Expanding the pipeline infrastructure will require evaluating CO_2 purity and delivery pressure, barriers to pipeline expansion, and capital cost. Each of these topics is addressed, followed by discussion of the pipeline "hub" concept.

6.2 CO_2 Delivery Pressure, Purity

The pressure and purity to which CO_2 is prepared determines the cost and design of pipeline infrastructure. CO_2 is most economically transported when the content is at least 95 percent by volume and compressed to pressure defined as the supercritical state (at least 1,070 psig and 88ºF). This results in a dense phase liquid. Combustion byproducts that contaminate the CO_2 stream should be almost completely removed. These issues are addressed subsequently.

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[126] Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, 2019, National Petroleum Council. Available at: https://dualchallenge.npc.org/. Hereafter NPC Report. Hereafter National Petroleum Council 2019 Report.
[127] Ibid. See Figure 6-2.

6.2.1 CO_2 Pressure

The high-density, supercritical phase is optimal for transport as CO_2 behaves more like a liquid than a highly compressed gas. This enables pumps to be used instead of compressors, thus lowering transport costs. The pressure to generate supercritical CO_2 requires at least 1,070 psig, although some applications employ pressure as high as 2,200 psig.[128] Consequently, the potential for delivery pressure of 2,200 psig requires pipeline wall thickness to be greater compared to that for natural gas**.** Moisture should be removed to minimize corrosion. Typical transport pressures range from 1,200 to 2,200 psig, creating the very dense phase that enables geologic injection for sequestration or EOR.

Because of their high operating pressures, CO_2 pipelines are subject to the same safety regulations as hazardous liquid pipelines rather than those applied to natural gas.[129] The association of CO_2 pipelines with the term "hazardous" can create a misperception with the public.

6.2.2 CO_2 Transport and Injection Specifications

Composition of CO_2 byproduct are those historically associated with natural gas processing, such as oxygen (O_2) and hydrogen sulfide (H_2S). In the case of CO_2, they also include other species such as methane and nitrogen. These constituents must be minimized to prevent corrosion and to not alter the properties of the condensed CO_2 that affect transport. Carbon monoxide (CO) can prompt corrosion as can water, which allows the formation of certain hydrates. Oxygen is to be minimized to meet requirements for EOR and saline injection, to avoid algae growth, and corrosion. Glycol can damage pump seals.

Table 6-1 summarizes the recommended specifications for content of CO_2 typifying various pipeline operators throughout the U.S.[130] This content is advised to support the least-cost CO_2 transport.

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[128] NPC 2019_Report. Chapter 6, Table 6-1.
[129] Title 49 of the Code of Federal Regulations, Part 195, Transportation of Hazardous Liquids by Pipeline.
[130] NPC 2019 Report. Chapter 6.

Table 6-1. Recommended Specifications for CO_2 Transport, Saline and EOR Injection

	Units	Numerical Range
CO_2	% by volume	>95
Water	ppm by volume	250-950
H_2S	ppm by weight	<10-45
Total Sulfur	ppm by weight	<10-35
Nitrogen	% by volume	<0.9 – 4
Oxygen	ppm by volume	<10
Hydrocarbons	% by volume	<4 to 5
Temperature	ºF	<90 – 120
Glycol	Gallons/Mcf	<0.3

6.3 Barriers to Pipeline Expansion

The key barriers to pipeline expansion are (a) acquiring permits and the associated topics of right-of-way access and eminent domain; (b) the role of individual state mandates; (c) the perception of sensitive habitat and cultural features; and (d) cost.

6.3.1 Permits and Right-of-Way Access

Present regulations specify the permitting and siting of CO_2 pipelines as under the purview of state authority. However, considering the magnitude of pipeline buildout required if CCUS were widely deployed, state-by-state authority may be inadequate for interstate projects. Some degree of federal control may be required to secure interstate permits, like that of interstate natural gas pipelines.

Permits cannot be acquired until right-of-way is secured. A key consideration is the potential for the project developer to invoke eminent domain, which is the right of a government entity (including state and federal governments) to acquire private property for beneficial public use. Two criteria to invoke eminent domain must be met: there must be a clear benefit for “public use,” and “just compensation” must be offered to the property owner. There are various means to determine public use and benefit. One criterion is “natural resource takings” provisions with states such as Idaho, Wyoming, and Colorado embedding such rights in the state constitution.

Proposed pipeline networks that clearly serve a public purpose – accumulating CO_2 from various sources for terrestrial sequestration or EOR – may provide a convincing case for eminent domain. Developing permits for wide-scale deployment will require significant cost and time.

6.3.2 Individual State Mandates

States can impose additional standards for intrastate transport but cannot do so for interstate transport.[131] For example, Wyoming requires specific pipeline casings and site requirements for right-of-way associated with the state highway system.[132] Texas requires CO_2 pipeline operators to employ certain corrosion-resistant materials, limit pipelines near schools, and engage in public safety education of this topic.[133] States also can establish siting authorities and mechanisms for local governments to participate, and establish "set-back" or industrial permitting requirements.[134]

The cumulative effect of these regulations is a strong safety record. DOE reports between 1986 and 2008, a total of 12 accidents across what was then a 3,500-mile pipeline network was reported.[135] No injuries or fatalities were reported from these incidents. One incident reported since this time frame was a February 2020 pipeline breach in Satartia, MS.[136] The pipeline breached transported CO_2 not processed from CCUS, but rather naturally-occurring CO_2 from the extinct volcano known as Jackson Dome. The pipeline was believed to contain hydrogen sulfide.[137]

6.3.3 Public Safety Perception

The high CO_2 pressure required for transport is the basis for regulation by the Department of Transportation (DOT) under Title 49 of the Code of Federal Regulations (Part 195, Transportation of Hazardous Liquids by Pipeline). As noted previously, association of CO_2 pipelines with "hazardous" regulations can be a barrier in acquiring permits. DOT regulations define CO_2 as a non-flammable gaseous hazardous material but not a hazardous liquid. However, some of the safety regulations applied to hazardous liquid pipelines, as defined by the Pipeline Hazardous Material and Safety Administration (PHMSA),[138] must be observed.

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[131] Righetti, T.K., Siting Carbon Dioxide Pipelines, Oil and Gas, Natural Resources and Energy Journal, Volume 3, Number 4. November 2017. Hereafter Righetti 2017.
[132] WYDOT Rules and Regulations, Utility Accommodations Section, WYO. DEP'T OF TRANSP. Available at: http://www.dot.state.wy.us/files/live/sites/wydot/files/shared /Management_ Services/utility%20accommodations%20section %20rules/utl10.pdf.
[133] TEX. ADMIN. CODE tit. 16, §§ 8.301-8.315 (2017).
[134] Righetti, 2017.
[135] Grant 2018 DOE/NETL Workshop.
[136] https://www.clarionledger.com/story/news/local/2020/02/27/yazoo-county-pipe-rupture-co-2-gas-leak-first-responders-rescues/4871726002/.
[137] See: https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f.
[138] Title 49 of the Code of Federal Regulations, Part 195, Transportation of Hazardous Liquids by Pipeline.

6.4 Capital Cost

Capital costs for pipelines vary widely. The key metric is the cost per inch-mile. This varies depending on numerous factors, primarily the compensation for right-of-way. Terrain and other geologic factors also can have a major impact. Typically, the least-cost pipelines on a cost per inch-mile basis are those built in rural areas. They usually transgress land of low-to-modest economic value and are of extensive length that results in economies-of-scale. In contrast, the highest-cost pipelines typically are relatively short and built in commercial or residential areas with intermediate to high population density.

Table 6-2 presents example costs for pipelines constructed since 2009.[139] Table 6-2 reports the cost for pipelines constructed from 2009 through 2016 in six states requiring lengths from 2 miles to over 300 miles with pipe diameters from 6 inches to 24 inches. The cost per inch-mile varies by more than a factor of three. One of the costliest projects, the Denbury Gulf Coast Pipeline and the Denbury Green Pipeline, crossed extensive wetlands, marshlands, as well as sections of Galveston Bay. Another high-cost project – at nearly $200K per mile – is among the shortest at 9 miles but required horizontal directional drilling. In contrast, the least-cost pipeline is owned by Greencore Pipeline Company. One reason for the lower cost is 33 percent of right-of-way was acquired from public lands and the remaining 67 percent from ranchland.

Several business models can be considered to fund and operate a CO_2 pipeline. One option entails the public sector, where local, state, or federal governments finance the projects. The states of Alaska, North Dakota, and Wyoming have chartered corporations to achieve this end.

Alternatively, a private entity can assume financing and operation. Duke Energy has considered such actions, possibly in joint ownership with a third party.[140] The benefits include revenue from CO_2 or sharing emissions allowances.

Both federal and state incentives for financing CO_2 pipeline infrastructure exist. Federal incentives most notably include Master Limited Partnerships (MLPs), which are commonly used for oil and gas pipelines, and Section 45Q credits. State incentives typically consist of property tax exemptions, reduced income tax, reduction in sales tax on required process equipment, and – depending on the state regulatory structure – rate recovery.

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[139] NPC 2019 Report.
[140] Grant 2018 DOE/NETL Workshop.

Table 6-2. Comparison of Pipeline Cost, Physical Features: Seven Recent Examples

Pipeline Name/ Company	Green	Greencore	Seminole	Coffeyville	Webster	Emma	TCV/ Petra Nova
State	LA/TX	WY/MT	TX	KS/OK	TX	TX	TX
Year Constructed	2009/2010	2011/2012	2012	2013	2013	2015	2016
Length (miles)	320	232	12.5	67.9	9.1	2	81
Diameter (inches)	24	20	6	8	16	6	12
Maximum Pressure (psig)	2,220	2,220	1,825	1,671	2,220	2,319	2,220
Cost per Mile ($/mile)	3,044,000	1,372,700	480,000	928,500	3,190,000	750,000	N/A
Cost per inch-mile ($/in-mile)	126,823	68,635	80,000	116,062	199,176	125,000	N/A

6.5 CO_2 Transport "Hub"

The concept of transport "hubs" where geographically clustered CO_2 sources share pipelines for geologic sequestration or EOR is a means to lower CCUS cost. In contrast to "point-to-point" transport from a dedicated CO_2 source to a dedicated sink, the hub concept aggregates CO_2 from various sources to exploit economies of scale to reduce cost.

Several hubs already exist or are evolving internationally.[141] In North America, the Alberta Carbon Trunk Line transports CO_2 from a refinery and fertilizer plant in a shared pipeline for EOR. In the United Kingdom, the Net Zero Teesside hub transports CO2 from an NGCC power station and aggregates CO_2 from sources in the emissions-intensive Humber industrial sector for sequestration offshore.

The Energy Futures Initiative conducted a conceptual study[142] addressing the feasibility of three example CCUS hubs. These hypothetical hubs are assumed to be located within the Ohio River Valley, Wyoming, and on the Texas/Louisiana Coast. Table 6-3 summarizes the estimates of total CO_2 reduction potential and potential hub sources and sinks.

Three ventures to develop pipeline hubs are being considered in the U.S.[143] Navigator Ventures is evaluating a 1,200-mile hub or "common carrier" pipeline through Nebraska, Iowa, South Dakota, Minnesota, and Illinois. This pipeline will be capable of transporting 12 million tonnes of CO_2 ($MtCO_2$) per year for storage in various Illinois sequestration sites. Summit Carbon is planning a 10 $MtCO_2$ per-year-capacity pipeline, primarily aggregating CO_2 from ethanol plants. ExxonMobil plans an extensive hub to aggregate CO_2 from the Houston Ship Channel for sequestration offshore in saline reservoirs in the Gulf of Mexico.

[141] *Building to Net Zero: A U.S. Policy Blueprint for Gigatons–Scale CO_2 Transport and Storage Infrastructure*, prepared by the Energy Futures Initiative, June 30, 2021. Available at: https://energyfuturesinitiative.org/efi-reports. See page 53.
[142] Ibid.
[143] Ibid.

Table 6-3. Conceptual CO_2 Hubs: CO_2 Reduction Potential, Sources, Sinks

Region	Potential CO_2 Reduction ($MtCO_2$)	Hub CO_2 Sources	Hub CO_2 Sink
Ohio River Valley	123	29 power generation, 19 iron and steel/aluminum, 5 chemicals manufacturing & production, 2 refineries, and 1 mineral plant	8 geologic storage sites, 855 miles of CO_2 pipelines
Wyoming	43	10 power generation, 4 refineries, 2 chemicals manufacturing and production, and 1 mineral plant	4 geologic storage sites, 443 miles of CO_2 pipelines
Texas/Louisiana Coast	171	47 chemicals manufacturing and production, 31 power generation, 25 refineries, 23 gas processing, 21 hydrogen and ammonia production, 3 iron and steel/aluminum production, and 2 paper/pulp production plants	5 geologic storage sites, 1,462 miles of CO_2 pipelines

6.6 Pipeline Takeaways

CO_2 pipeline infrastructure will require expansion by some estimates of up to a factor of 10 to support broad CCUS deployment. The following issues are to be considered:

- Experience exists in North America with CO_2 pipelines infrastructure, with a present inventory of 5,500 miles concentrated in oil-producing states and Canadian provinces. Some observers suggest an increase in pipeline capacity between four and more than ten-fold is necessary to support CCUS goals.

- CO_2 pipelines are distinguished from those for natural gas by significantly higher operating pressure, from a minimum of 1,070 psig to as high as 2,200 psig. As with natural gas pipelines, transported CO_2 meets certain specifications (see Table 6.1).

- Acquiring right-of-way, as determined by land ownership and state laws, is a challenging issue. The prospect of invoking eminent domain could be an option. Public perception of safety could be influenced by association of “hazardous” language describing regulations.

- The required capital is highly variable and depends on the length of the pipeline, the routing (and thus right-of-way), and the extent of contaminant removal. Most, if not all, pipeline enhancement actions will require some form of financial assistance.

- Although the present point-to-point arrangement of pipelines are effective for existing projects, they may not provide the least-cost transport. The “hub” arrangement that aggregates CO_2 from multiple sources for a “common carrier” for disposition at multiple sequestration or EOR sites could exploit economies of scale for financing, construction, and permitting.

7 Enhanced Oil Recovery (EOR)

The use of CO_2 for EOR is of significant and immediate interest. Six of the 11 CCUS projects described in Sections 3 and 4 cite EOR as the primary CO_2 fate. Adequate pipeline capacity already exists for most of these projects, almost all of which are at or near existing pipelines. That EOR fields can retain CO_2 is not in question. Natural gas and oil have been entrapped in such formations for millions of years. Also, EOR provides the collateral benefit of lowering life-cycle emission of CO_2 for oil extraction by up to 63 percent.[144] However, not all oil fields are amenable for EOR and detailed evaluation is required to assess feasibility.

7.1 Overview

EOR – defined as the use of CO_2 at supercritical conditions to displace oil within reservoirs – is broadly practiced in North America. A total of 1 B tonnes of CO_2 have been sequestered using EOR in the U.S. in the last 40 years. Figure 7-1 overviews the location of major oil fields evaluated as favorable.[145] For some oil fields, the factor limiting the use of CO_2 as EOR is simply CO_2 availability at a price that supports favorable oil production. For others, the physical features of the field and production history affect this feasibility.

EOR beneficially affects CCUS economics in multiple ways. They include:

- The upfront cost to deploy EOR can be less than opening a new geologic sequestration site because the geologic characteristics of the field already have been determined.
- Pipeline infrastructure may exist at or within reasonable proximity to a potential CO_2 source, minimizing new pipeline investment.
- The injection wells for EOR are less complex to permit and are less costly compared with the injection wells required for sequestration.
- The cost to secure CO_2 through EOR can be offset through revenue to increase oil production and Section 45Q tax credits. The credits start at $19/tonne in 2019 and rise to $35/tonne in 2026, and subsequently escalate with inflation.

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[144] IEA 2015 CO_2 EOR and Storage.
[145] 2015 DOE/NETL Storage Atlas. Graphic 17.

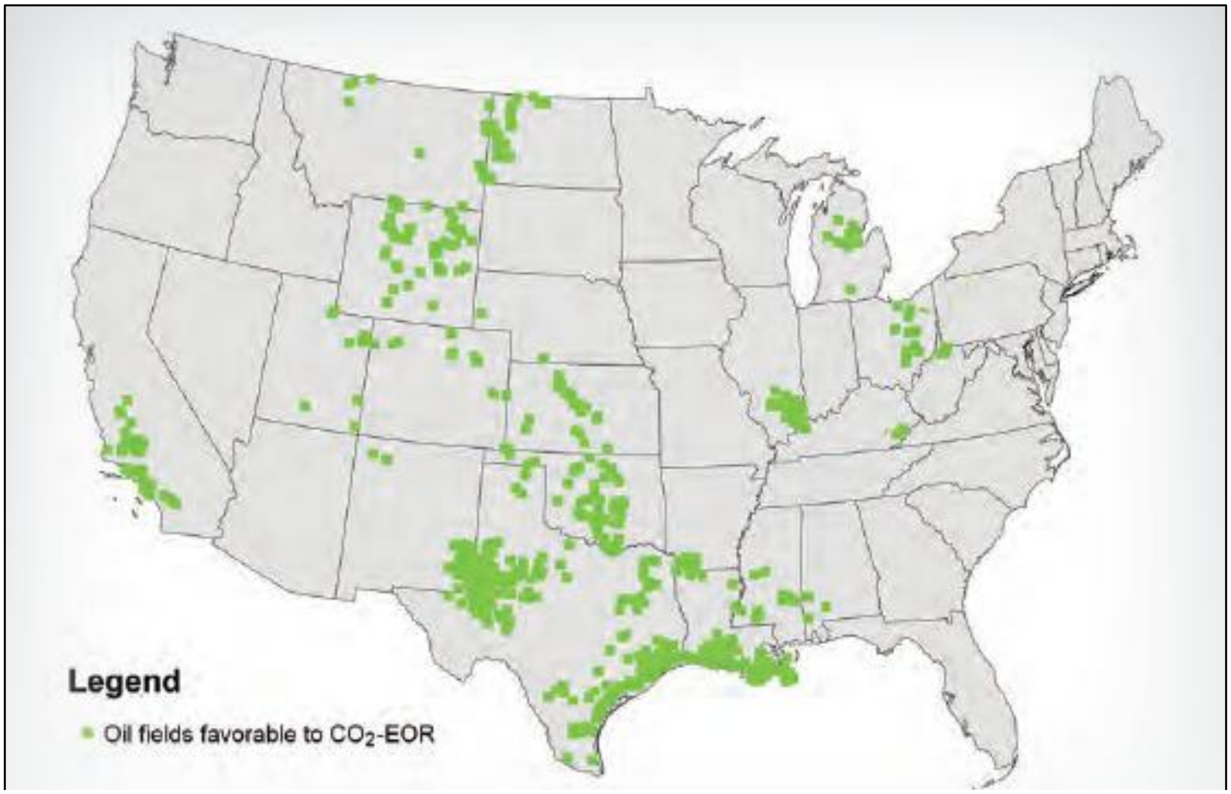

Figure 7-1. Major Oil Fields in the U.S. Identified as Favorable to EOR

There are many examples of EOR sites. Among the more prominent are the Denver Unit in the West Texas Permian Basin, Bell Creek Field in the Powder River Basin of Montana, and the Northern Nigeran Pinnacle Reef Trend in the Michigan Basin. Perhaps the largest regional collection of EOR sites is the Texas Permian Basin, which a recent DOE study described as "too numerous to count."[146]

7.2 CO_2 Storage Capacity

There are more than 150 EOR projects operating worldwide.[147] Estimates of CO_2 storage via EOR have been developed for North America and worldwide. Even the lowest estimates suggest adequate capacity to support significant CO_2 storage.

The American Petroleum Council (APC) estimates CO_2 storage capability according to several categories of EOR sinks, with the largest sinks being Onshore Conventional, the Residual Oil Zone, and Unconventional.[148] The APC reports CO_2 storage in the U.S. for two scenarios: *Present Capabilities* reflecting existing technology, and *Strong Economics/Improved Technology* reflecting a combination of state-of-art technologies and strong economic growth. The estimate for the *Present Capabilities* scenario ranges from 55 B tonnes to 119 B tonnes, with the *Strong*

[146] Balch, R., CUSP: The Carbon Utilization and Storage Partnership of the Western US, NETL Workshop on Representing Carbon Capture and Utilization, October 2018.
[147] APC Report. See Chapter 8, Table 8-1.
[148] Ibid.

Economics/Improved Technology scenario projected to provide 274 B tones to 479 B tonnes of storage.[149] Separate from the APC analysis, the DOE/NETL Storage Atlas estimates U.S. EOR storage ranges from 186 B tonnes to 232 B tonnes.[150]

7.3 EOR Economics

The economics of EOR depend on CO_2 delivery pressure, the geologic characteristics of the target formations(s), and whether the field is operated to maximize CO_2 storage or additional oil production. Pipeline transport is an additional consideration. These are elaborated as follows:

<u>CO_2 Physical Features</u>. CO_2 is most effective displacing oil when injected as a fluid that is miscible with oil, creating one homogeneous fluid. This is accomplished by injecting CO_2 at supercritical pressure, above 1070 psig.[151] Not all EOR fields can sustain such pressure. Some fields may be limited by the geologic characteristics of the caprock that seal the oil or natural gas in the target reservoir and be required to operate at lower pressures.

<u>EOR Objective</u>. EOR economics are affected by the objective of the site. It can be either to maximize oil production while using minimal CO_2, or maximizing CO_2 secured in exchange for additional oil produced. Additional CO_2 can be injected into a target formation above and beyond what may be needed for maximizing oil recovery.[152]

EOR in the U.S. has historically been used to maximize oil production, with securing CO_2 as incidental. Most EOR operations employ this scenario, termed *EOR Light* by the IEA.[153] It utilizes and thus "stores" 0.3 tonnes of CO_2 per bbl of oil produced. The incremental oil produced using this scenario increases by 6.5 percent over the original inventory. IEA also studied an *Advanced EOR* scenario, increasing both CO_2 secured, and oil recovered. The CO_2 secured increased to 0.6 tonnes per bbl of oil recovered, and oil production increased by 13 percent. A *Maximum EOR* scenario further increased CO_2 secured to 0.9 tonnes of CO_2 per bbl oil, increasing oil production by 13 percent.

Some stakeholders have asked how an increase in EOR affects the global CO_2 budget. That is, does promoting EOR compromise benefits provided by CCUS? To the contrary, the IEA estimate that EOR avoids CO_2 that would otherwise be generated during "conventional" oil extraction – providing a 63 percent reduction.[154]

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[149] Ibid.
[150] 2015 DOE/NETL Storage Atlas.
[151] Injected CO_2 in supercritical (e.g., liquid) state is miscible with oil and reduces the viscosity, enabling displacement from the pores. The required pressure in the reservoir is typically about 75 bar (for light crude oil) at temperatures of about 70ºC.
[152] The market price for CO_2 is generally 1 to 2 percent of the price of oil, as cost per mcf of CO_2. See Grant, T.C., An Overview of CO_2 Pipeline Infrastructure, NETL Workshop on Representing Carbon Capture and Utilization, October 2018.
[153] IEA 2015 CO_2 EOR and Storage.
[154] Ibid.

CO_2 Separation Processes. Although CO_2 is trapped within the reservoir as oil is displaced, a portion of injected CO_2 is returned to the surface with the "produced" oil and gas. The CO_2 that returns must be separated from the oil and gas and re-injected to achieve a true closed-loop system so all CO_2 is retained within the reservoir. The cost for process equipment to separate, measure, recycle and return CO_2 affects EOR feasibility.

Pipeline Transportation Corridor. One factor that can favorably affect EOR economics is the use of a transport corridor, or "hub" as described in Section 6. The "hub" strategy enables multiple EOR sites to acquire CO_2 from multiple sources, each sharing the cost for common elements of the pipeline. It is anticipated to cost less than conventional point-to-point transport, where a single CO_2 source and oil field bear the entire pipeline investment. This arrangement already exists in the Permian Basin. This "hub" pipeline complex also serves the Weyburn field in Canada.

7.4 EOR Injection Well Requirements

The U.S. Environmental Protection Agency (EPA) regulates the injection of CO_2 into underground oil and natural gas reservoirs under the provisions of the Safe Drinking Water Act (SDWA). EPA, or alternatively states in many cases, permit underground injection of CO_2 for EOR through the Underground Injection Control (UIC) Program. The UIC Program is responsible for assuring that the injection of CO_2 and other fluids into underground formations does not compromise groundwater quality and ensures the injected material is retained in target injection zones. There are six classifications of underground injection wells, enumerated as Class I through VI. The injection wells for EOR are required by EPA to abide by Class II design criteria.[155] The Class II well requirements address well design and an evaluation of the potential for injected CO_2 to migrate to the surface. A permit demonstrating how the well will satisfy the requirements of the program must be obtained prior to initiating injection of CO_2 for purposes of EOR.

Although the UIC Program is a federal regulation, states have the option of assuming responsibility for implementation. Thirty-four states have adopted at least some portion of the responsibility. The permitting of Class II wells for EOR is well established. EPA estimates there are over 180,000 Class II injection wells in the U.S. and as much as 80 percent of those wells are used for EOR.

7.5 EOR Supporting CCUS Projects

As noted previously, two of the four NGCC and four of the eight coal-fired projects or FEED studies in North America seek to utilize EOR. Successful implementation of the projects relies on revenue that can be generated from the implementation of the EOR component of the project. These sites either are currently operating or are well characterized and expect to be operating soon. The sites are discussed in order of longevity (those operating for the most time) as follows:

[155] The federal requirements for Class II wells are found at 40 CFR Parts 144 – 148 or at 42 USC 1421, 1422, 1423, 1425, 1426, 1431, 1442, and 1443.

Weyburn. The Weyburn (and nearby Midale) oil fields in the southeastern portion of Canada's Saskatchewan province have deployed EOR since 2000. Weyburn is the primary EOR site for CO_2 captured from Boundary Dam Unit 3 and is considered the prime repository for the proposed Shand CCUS application. EOR activities initiated in 2000 are predicted to extend the active "life" of these fields by 15 to 20 years. Further, it is estimated that 18,000 bls of the daily 28,000 bls produced are considered incremental and attributable to EOR. As of July 2018, 38 M tonnes of CO_2 have been stored within the Weyburn oil field. Expanding to a nearly adjacent field offers the potential for storage of an additional 230 M tonnes.[156]

West Ranch. The West Ranch oil field in Jackson County, TX, is the repository for CO_2 from the NRG Petra Nova project. It is accessed via an 81-mile pipeline. For a three-year duration from 2016 through 2019, more than 3.5M tons of CO_2 have been injected at West Ranch. A CO_2 accounting program was implemented in March 2017 to provide information on injection and movement of CO_2 among the fields that comprise the West Ranch site. Results show 99.08 percent of CO_2 injected was sequestered, meeting the DOE 99 percent target.[157]

As of January 2020, DOE reported Petra Nova captured more than 3.9 million short tons of CO_2 and that EOR has produced an additional 4.2 million barrels of oil using EOR since project inception in 2016.[158] This actual production rate is less than some observers say was planned[159] but the reasons why – either operational or lack of supply – are unknown.

Elk Hills. The Elk Hills oil field in Kern County, CA, has operated since 1911 and is the sole repository for CO_2 proposed to be captured from the Elk Hills NGCC station located within the oil field. Elk Hills has yet to deploy EOR and is evaluating injection well designs and acquiring Class II permits. The Elk Hills Station reports participating in the project will lower lifecycle CO_2 emission from oil extraction by 40 to 50 percent.[160]

Permian Basin. Numerous oil fields employ EOR in the Permian Basis. More than 70 such applications were noted in 2013[161] with additional projects since recorded. Of interest is the Kinder Morgan Cortez pipeline that is proposed to deliver CO_2 from the San Juan CCUS project to the Permian Basin. The Cortez pipeline extends 123 miles to transport CO_2 from the McElmo Dome to six oil fields: Goldsmith, Katz Unit, SACROC, Tall Cotton, Yates, and Sharon Ridge.[162] The Cortez pipeline passes within 21 miles of the San Juan Generating Station and should possess adequate capacity to accommodate additional CO_2 from the project.

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[156] Shand CCS Feasibility study.

[157] Petra Nova/Parish March 2020 report.

[158] See: https://www.energy.gov/fe/articles/happy-third-operating-anniversary-petra-nova.

[159] Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign, August 2020, Institute for Energy Economics and Financial analysis. Available at: https://ieefa.org/wp-content/uploads/2020/08/Petra-Nova-Mothballing-Post-Mortem_August-2020.pdf.

[160] Bhown 2020.

[161] The Status of CO_2 EOR in Texas: CO_2 for EOR as CCUS: A Collaborative Symposium on CO_2 EOR, Rice University, November 19, 2013. Melzer Consulting.

[162] See: https://www.kindermorgan.com/Operations/CO2/Index#tabs-enhanced_oil_recovery.

The other EOR fields that serve the large-scale tests and FEED studies includes the Salt Creek oil field in Kent County, TX, that is a potential repository for CO_2 from the Golden Spread Mustang Station. The Salt Creek field and has employed CO_2 injection since 1994.[163]

7.6 EOR Takeaways

- EOR can provide a reliable means to sequester CO_2. This practice is routine in the petroleum industry and candidate oil fields are already geologically characterized. However, candidate oil fields must exhibit certain physical characteristics and present conditions in which CO_2 and oil are miscible at high pressure to be successful.

- CO_2 injection wells for EOR are designed to meet the requirements of EPA Class II wells. This provides for safe CO_2 injection while the well designs are less complex than Class VI well designs required for sequestration.

- The DOE/NETL estimated the present CO_2 storage capacity ranges from 186 B tonnes to 232 B tonnes. The petroleum industry projects that improved injection methodologies would elevate storage to 247 B tonnes to 479 B tonnes.

- The ability to utilize EOR can be enhanced, and the cost can be lowered with CO_2 pipeline "hubs" or transportation corridors. Existing examples include the Permian Basin and the Weyburn Field.

- The revenue for CO_2 to increase oil production, combined with Section 45Q tax credits, can effectively offset the cost of CCUS. Section 9 presents an example for a specific hypothetical case.

[163] See: https://www.ogj.com/home/article/17212186/mobil-starts-up-west-texas-co2-recovery-project.

8 Sequestration

There are numerous and broadly distributed options for CO_2 sequestration via geologic storage across North America. Estimates of CO_2 storage capacity via sequestration vary widely but the available capacity exceeds that for EOR. The storage capacity within deep saline reservoirs offers by far the largest opportunity, with estimates ranging from 2,618 B tonnes to potentially 21,978 B tonnes of CO_2.[164] Similarly, the estimated cost for CO_2 storage is highly variable depending on the geologic characteristics of the formation. For example, one planned site in the Southeastern U.S. projects a sequestration cost of $3/tonne.[165] On the other hand, a national evaluation projects a range from $8/tonne to$18/tonne,[166] depending on the formation.

8.1 Overview

Geologic storage of CO_2 is defined as the high-pressure injection into underground rock formations that – because of their inherent properties – encase CO_2 and prevent migration to the surface. The ideal repository for CO_2 requires several features: significant injectivity, significant storage capacity, and a geologic "seal" or impermeable caprock to permanently retain the injected CO_2 in the reservoir.

The best candidate formations feature high porosity and interconnected pathways to disperse CO_2 throughout the formation. Ideal subsurface formations are found at depths of a mile or more below the surface and contain ample pore space that is typically filled with saline. The saline is readily displaced by injected CO_2. CO_2 is most effectively stored when injected in the liquid state, requiring supercritical pressures. Injection depths of at least 1 km (~0.56 mile) are generally required for injected CO_2 to remain in a supercritical, liquid state.

Candidate storage formations must feature an impermeable caprock overlying the target formation to prevent migration of injected CO_2 to the surface. These caprock formations become of increasing importance with the life of the sequestration site as CO_2 injection displaces saline water, increasing the reservoir pressure. The ideal formation features alternating layers of low- and high-permeability rock. This allows the high-pressure saline and injected CO_2 to expand but remain contained below the impermeable rock layers.

[164] 2015 DOE/NETL Storage Atlas.

[165] Riestenberg, D. et. al., *Establishing an Early Carbon Dioxide Storage Complex in Kemper County*, Mississippi: Project ECO2S, DOE/NETL Carbon Capture Front End Engineering Design Studies and CarbonSAFE 2020 Integrated Review Webinar, August-17-19 2020. Hereafter Riestenberg 2020 Review Webinar.

[166] Rubin, E. S., Davidson, J. E., and Herzog, H. J. (2015). "The Costs of CO_2 Capture and Storage," *International Journal of Greenhouse Gas Control*, http://dx.doi.org/10.1016/j.ijggc.2015.05.018.

That reservoirs with these physical features can permanently retain CO_2 is not in question. Such formations have entrapped natural gas, oil, and CO_2 for millions of years. Notably, the Pisgah Anticline located near the Jackson Dome in Mississippi has entrapped CO_2 for 65 million years.

8.2 CO_2 Storage Capacity

Saline formations offer the largest potential for CO_2 storage. NETL estimates a minimum of 2,379 B tonnes of CO_2 to as high as 21,633 B tonnes can be stored.[167] These estimates reflect initial potential capacity and do not account for factors that could limit storage as CO_2 is injected, such as elevated reservoir pressures attributable to injection in adjacent formations.[168]

There are forms of geologic storage other than saline reservoirs, including unmineable coal seams, depleted natural gas reservoirs, depleted oil reservoirs, and sedimentary basins. These should not be ignored as each could offer sequestration near a CO_2 source. But in North America most of the storage capacity exists as saline reservoirs.

Since the mid-1990s numerous CO_2 storage projects worldwide have been completed or are underway. The earliest exercises were in Norway, at the Sleipner (1Mtpa since 1996) and Snohvit projects (0.8 Mtpa since 2008). In the U.S., the Fri pilot plant (1.6 kilotonnes) operated from 2004 to 2009. During approximately the same time frame, the Salah project (1 Mtpa 2004-2011) operated in Algeria. These and other efforts established the technical basis for initiatives in North America that have been completed or are underway or planned. Examples in the U.S. include the Illinois Basin-Decatur project (1 Mtpa 2011-2014), the follow-on Illinois Industrial project (1 Mtpa since 2017), and the Citronelle test site at Plant Barry (~115 kt 2012-2014). In Canada, the Aquistore (110 Kt 2015-2017) and Quest (1 Mtpa since 2015) projects are operating.

These projects support the sequestration of CO_2 from five NGCC and coal fired CCUS projects.

8.3 Sequestration Economics

The economics of sequestration depend on geologic characteristics that affect CO_2 "injectivity" (how easily CO_2 and water migrate from the injection site to the reservoir), the capacity of the field, and the anticipated monitoring and closure activities.

The cost of sequestration in saline reservoirs is determined by factors previously cited (the porosity and permeability of the reservoir rock, and the presence of impermeable caprock). Also important is the arrangement. Ideally, there are alternating layers of porous and impermeable material. The depth below the surface of a secure formation is also a factor, as this determines the depth and design of injection wells. EPA classifies geologic sequestration wells under the UIC Program as Class VI wells. Class VI injection wells require extensive engineering and site

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[167] NETL Carbon Storage Atlas.

[168] Baik, E. et al. (2018). "Geospatial analysis of near-term potential for carbon-negative bioenergy in the United States." *Proceedings of the National Academy of Sciences*, 115(13), 3290-3295.

analysis. For any potential sequestration site, the number of these wells, their separation, and the penetration depth can significantly contribute to sequestration cost.

NETL has developed a model to estimate the cost for CO_2 sequestration in geologic formations by factoring in the attributes of the site, the design of injection wells, and mass of CO_2 injected.[169] The model predicts sequestration cost in saline reservoirs – exclusive of pipeline capital and operating costs – to range from $1/tonne to $18/tonne. The model predicts a narrower range of $8/tonne to $13/tonne when exercised to reflect conditions relevant to most U.S. application.[170]

8.4 Class VI Well Requirements

As described for EOR, the Safe Drinking Water Act's UIC Program is responsible for assuring that injection of materials into subsurface terrestrial formations does not compromise groundwater quality and does not escape to the surface. EPA issued Class VI well permitting rules for CO_2 injection sites that affect all aspects of sequestration site design and operation. The Class VI well rules require extensive site characterization and define overall permit content. This includes requirements for well construction and operation, groundwater testing, monitoring, recordkeeping, reporting, remedial response, emergency response, and the sealing and post-closure management of wells. The operator of the storage facility must demonstrate financial assurance for continued duty, even if the operator were to become financially insolvent. As noted in the discussion for EOR, 34 states have elected to adopt at least some portions of EPA's UIC program. However, to date only Wyoming and North Dakota have applied for and been granted primacy for Class VI permitting requirements. Acquiring Class VI permits can be a rate-limiting step in securing a sequestration site. Improving the evaluation and approval process is desired to shorten this time span. EPA listed on its website two active Class VI wells for geologic sequestration and one pending permit application, as of August 9, 2021.

8.5 Proposed Sequestration Sites

The sequestration sites supporting the CCUS projects described in Sections 3 and 4 are being evaluated in detail or have operated for years. Several examples are presented as follows:

San Juan Basin.[171] The feasibility of saline storage in northwest New Mexico is being evaluated for the proposed San Juan Generating Station CCUS project. The results of this study will define the CO_2 injection design and Class VI well permit application to sequester the estimated 6 M tonnes/y of CO_2 generated.

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[169] *FE/NETL CO_2 Saline Storage Cost Model: Model Description and Baseline Results*, July 18, 2014, DOE/NETL-2014/1659.

[170] Rubin 2015. See Table 13.

[171] Ampomah, W., *San Juan Basin CarbonSAFE Phase III: Ensuring Safe Subsurface Storage of CO_2 in Saline Reservoirs*, DOE/NETL Carbon Capture Front End Engineering Design Studies and CarbonSAFE 2020 Integrated Review Webinar, August-17-19 2020.

The San Juan Basin exhibits good characteristics for CO_2 sequestration. It has multiple sandstone zones with good permeability and porosity interspersed with layers of low permeability material (overlying shales and carbonates) that provide a seal. Three specific reservoirs with these "stacked" characteristics appear most suitable, the Salt Wash, Bluff, and Entrada reservoirs. Further, these three reservoirs are relatively close (~5 miles) to the Kinder Morgan Cortez CO_2 pipeline. CO_2 can be delivered from the San Juan Generating Station to any of the three reservoirs by a dedicated point-to-point pipeline of approximately 25 miles or a 20-mile pipeline that utilizes portions of the Cortez pipeline. This evaluation will consider the impact of approximately 2,500 existing oil and gas exploration and production wells within 10 miles of the proposed sequestration site. Means to cap or otherwise eliminate their role in CO_2 migration will be addressed.

This project is targeted to submit final injection well design and permit application in mid-2022, anticipating approval in mid-2023.

<u>Kemper County</u>.[172] A CO_2 storage complex to provide sequestration for up to three generating stations is designed for Kemper County, MS. Three reservoirs are contained within the 30,000-acre Kemper County facility: Massive Sand/Dantzler, Washita-Fredericksburg, and Paluxy. Each reservoir features subsurface sandstone layers at greater than 1,300 feet, exhibiting good porosity and permeability. Interspersed between the sandstone are layers of mud rock and chalk, which due to low permeability act as a seal. The mean value of the estimated storage capacity for all three reservoirs is 1,200 G tonnes of CO_2. Southern Company reports the permits for these Class VI wells are in-hand,[173] qualifying the site as storage-ready.

Three generating stations are candidate sources for CO_2. They are:

- Kemper County Energy Facility, requiring a 5-mile pipeline and generating 0.87 M tonnes/y of CO_2,
- Plant Miller, requiring a 150-mile pipeline and generating 18.8 M tonnes/y of CO_2, and
- Plant Daniel, requiring a 180-mile pipeline and generating 3 M tonnes/y of CO_2.

The estimated cost for CO_2 storage at Kemper County is lower than that deduced using the DOE/NETL model.[174] A capital requirement of \$60.6 M is necessary to develop capability to store 3 M tonnes. Annual operating cost is estimated at \$2 M for a 12-year period, while post-injection annual operating and closure cost of \$1.3 M is estimated for a 10-year period. These costs comprise a net present value of about \$30 M, equating to less than \$3/tonne of CO_2 stored.

<u>Wyoming CarbonSAFE Storage Complex</u>.[175] The feasibility of a multi-use site providing either sequestration or EOR is being evaluated in Campbell County, WY, to support the Dry Fork CCUS project. This storage site targets a capability of 2.2 M tonnes annually at three locations

[172] Riestenberg 2020 Review Webinar.
[173] Ibid. Graphic 14.
[174] Rubin 2015. See Table 13.
[175] McLaughlin, J. et. al., *Wyoming CarbonSAFE: Accelerating CCUS Commercialization and Deployment at Dry Fork Power Station and the Wyoming Integrated Test Center*, DOE/NETL Carbon Capture Front End Engineering Design Studies and CarbonSAFE 2020 Integrated Review Webinar, August-17-19 2020.

within the storage complex. Exploratory test wells have been drilled to almost 10,000 feet, providing samples from candidate reservoirs and seal layers. Preliminary estimates project almost 54 M tonnes of CO_2 can be injected within two reservoirs, the Lower Sundance and Upper Minnelusa. In addition to EOR options at this site, the nearby Greencore CO_2 pipeline enables transport to EOR options.

Present work is further exploring the relationship between CO_2 injectivity, pressure response to injection, and geologic formation heterogeneity. The Class VI well designs and permit applications are to be filed and approval process managed. Completion is targeted by 2022.

Project Tundra.[176] This study evaluates the feasibility of sequestration using two storage sites near Center, ND, adjacent to the Milton R. Young Generating Station. The feasibility of deploying EOR in the nearby Williston Basin oil and gas fields also is considered. The results of this study – planned for mid-2022 – will be used to prepare an injection design and Class VI well permit application to store approximately 3.1 M tonnes/y of CO_2 as generated by the MYGS.

This project is targeted to submit final injection well design and permit application in mid-2022, anticipating approval in mid-2023.

8.6 Region-Wide Initiatives

Several initiatives are underway to explore regional infrastructure connecting CO_2 sources to a variety of sites. These activities are conducted under the auspices of the DOE CarbonSAFE initiatives, multi-phase efforts to develop sites for CO_2 storage available for the 2025 timeframe.

These are summarized as follows:

Integrated Midcontinent Stacked Carbon Storage.[177] This activity is evaluating the feasibility of a regional storage hub employing CO_2 sources in eastern and central Nebraska for transport southwest via a common CO_2 pipeline corridor to Red Willow County, NE. The storage site in central Kansas is comprised of alternating layers of deep saline formations, oil-bearing reservoirs, and shale formations. The CO_2 sources within this region include several ethanol plants totaling more than 5 M tonnes CO_2 as well as various electric generating units. Four of the electric generating units and one local refinery in total emit 20 M tonnes of CO_2 annually. Both saline sequestration and EOR can be carried out within this region. Specific sequestration sites evaluated are Madrid in Perkins County, NE, and the Patterson-Heinz-Hartfield site in Kearny County, KS. EOR is an option at the Sleepy Hollow Field in Red Willow County, NE. The study is evaluating pipeline routes that serve the collective needs. Cumulatively, these sites could store 578 Mt of CO_2 while the 17 oil fields could produce 182 MM bbl of oil, potentially generating $30.9 B in revenue.

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[176] Peck, W., *North Dakota CarbonSAFE Phase III: Site Characterization and Permitting*, Project DE-FE0031889, DOE/NETL Carbon Capture Front End Engineering Design Studies and CarbonSAFE 2020 Integrated Review Webinar, August-17-19 2020.

[177] Walker, J., *Integrated Midcontinent Stacked Carbon Storage Hub*, DOE NETL Carbon Capture Front End Engineering Design Studies and Carbon Safe 2020 Integrated Review Webinar, August 17-19, 2020.

__Illinois Storage Corridor__.[178] The project will secure permits for CO_2 sequestration sites at two locations in Illinois, serving the Prairie State Generating Station and One Earth ethanol production facility. Key actions are acquiring 2D and 3D seismic data, drilling and testing two characterization wells, modeling injection performance, preparing the design for Class VI injectors, submitting applications, and securing approval for CO_2 injection wells at both sites.

These sequestration sites will target storing 450,000 tonnes/y of CO_2 from the One Earth LLC ethanol facility, and up to 6 M tonnes/y from the Prairie State Station. Both sites are rural with adequate land for sequestration.

This work is targeted to securing permits by mid-2023.

__Carbon Utilization and Storage Partnership__. This activity is evaluating existing data that describe potential sequestration sites in 13 states: – Arizona, California, Colorado, Idaho, Kansas, New Mexico, Nevada, Montana, Oklahoma, Oregon, Texas, Utah, and Washington. The focus is on evaluating existing data and using these in analytical models to evaluate CCUS potential. Oil and gas basins, sequestration in saline, and basalt are considered. Regional hubs can be identified that provide cost effective sequestration.

8.7 Sequestration Takeaways

- Estimated capacity for CO_2 sequestration in North America ranges from a minimum of 2,618 billion tonnes to 21,987 billion tonnes. Injection into deep saline reservoirs offers the largest capacity and is the most prominent but not the only option.

- The cost for CO_2 sequestration, as projected by NETL, will vary over a wide range from $1/tonne to $18/tonne, depending on site-specific conditions. For many applications NETL's cost estimate is $8/tonne to $12/tonne. In the case of the proposed Kemper County Facility – which has its design completed and permits reportedly acquired – the cost is projected to be approximately $3/tonne, reflecting the lower end of the cost range projected by the NETL.

- The evaluation of sites and development of a specific injection well design requires extensive data and modeling to assure low risk. Injection well designs require permits approved pursuant to EPA Class VI well regulations and include requirements for well construction and operation, groundwater testing, monitoring recordkeeping and reporting, remedial response, emergency response, sealing of wells, and post-closure management.

- Like EOR, the availability of sequestration can be enhanced and the aggregate cost lowered by a concerted effort to permit and construct CO_2 pipeline "hubs" or transportation corridors that serve an array of sequestration sites.

[178] Whittaker, S., *Illinois Storage Corridor*, DOE NETL Carbon Capture Front End Engineering Design Studies and Carbon Safe 2020 Integrated Review Webinar, August 17-19, 2020.

9 Installed Process Cost

9.1 Background

The most-widely referenced CCUS cost index is the cost to avoid a tonne of CO_2, as discussed in previous sections. This cost metric is the basis for most cost reimbursement mechanisms, such as Section 45Q credits, and is key to CO_2 emission trading schemes.

The cost to avoid a tonne of CO_2 is influenced by numerous factors, most notably unit generating capacity, capacity factor, facility lifetime, and capital requirement. Consequently, discussion of the $/tonne metric without these factors provides an incomplete description of cost. Section 9 thus addresses capital costs ($/kW, per net basis) and these factors.

Incurred costs for the CCUS project at SaskPower's Boundary Dam Unit 3 are fully reported[179] and those for NRG's Petra Nova project are partially reported.[180] These cost data reflect "first-of-a-kind" projects and are not representative of future applications (e.g., the "nth" design). The latter "nth designs" can benefit from long-term operating experience, larger generating capacity and improved economies of scale, and standardization of equipment design. Further, as the case for early-1980s FGD equipment, the modularization of design – i.e., applying three identical absorber vessels capable of treating 200 MW gas flow to a 600 MW unit – can contribute to cost savings. These and other factors are expected to lower CCUS capital cost.

Cost results for units other than Boundary Dam Unit 3 and Petra Nova are limited. SaskPower used experience from Boundary Dam Unit 3 to project costs for Shand. Costs for NPPD/Gerald Gentleman are developed to AACE Class 3 criteria and, thus, are approximate. Final FEED study reports for most projects were to be submitted to the DOE in late 2021, and publicly available in 2022.

[179] Giannaris et. al. 2021.
[180] Petra Nova 2020 Final Report.

9.2 Cost Evaluation

Figure 9-1 (a replicate of Figure 1-1) compares the metrics of avoided cost per tonne and capital requirement as presently available for five pulverized coal applications. Also shown are the NETL reference cases for pulverized coal and NGCC.

The results in Figure 9-1 present avoided cost per tonne on the left vertical axis and capital requirement on the right vertical axis. They are displayed in terms of increasing net generating capacity (e.g., accounting for auxiliary power consumed by the CCUS system). The planned lifetime of the facility (which determines capital recovery factor, and the annual costs incurred) and assumed capacity factor are reported in Figure 9-1. The design CO_2 removal (percent basis) for each project is 90 percent or more for all but one unit, the membrane process at Dry Fork.

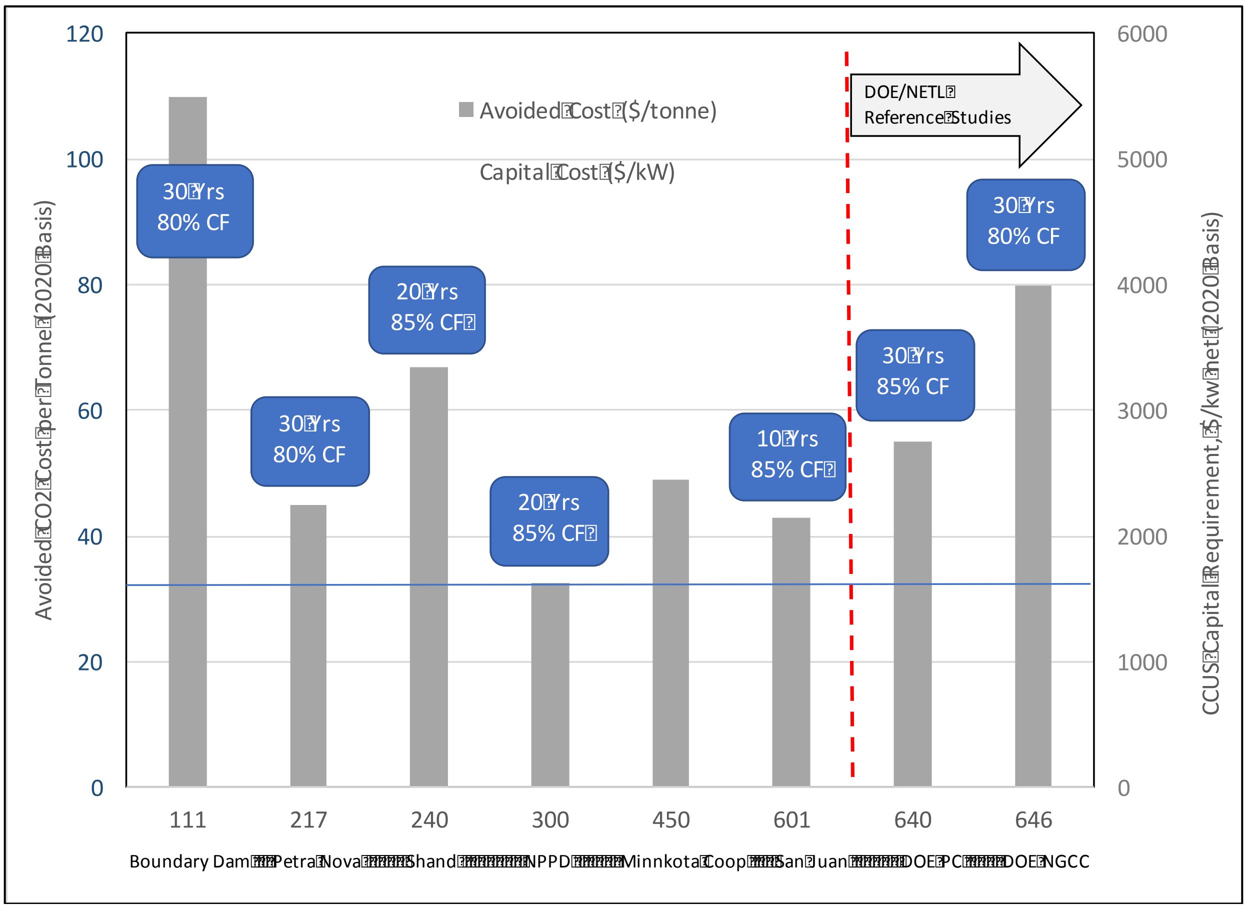

Figure 9-1. Capital Cost, Avoided CO_2 Cost per Facility Lifetime, Capacity Factor

Unless noted, costs in Figure 9-1 represent CO_2 produced at the fence line and do not consider transmission and storage, nor any credits for tax treatment.

9.2.1 NGCC

The four NGCC projects described in Section 3 (Golden Spread, Panda Sherman, Elk Hills, and Daniel Unit 4) were all scheduled to deliver cost estimates to DOE for internal review by late 2021 with data publicly available by the close of 1Q 2022.[181] The sole NGCC cost basis is the DOE/NETL 2019 study presently being updated.[182] As presented in Section 3, application of the 2017-vintage Cansolv process requires $1,600/kW for a site comprised of two F-Class gas turbines and HRSGs configured in a 2 x 2 x 1 arrangement. This process avoids CO_2 for $80/tonne based on an 85 percent capacity factor and 30-year plant lifetime.

9.2.2 Pulverized Coal

Figure 9-1 shows CCUS capital cost per net generating capacity decreases with increasing generating capacity. This trend in Figure 9-1 could also be affected by project timing. The largest capacity projects are the ones most recently proposed and with the least opportunity for detailed study.

For example:

- SaskPower Boundary Dam Unit 3 reports the highest capital requirement and cost per tonne, as these costs are a consequence of the first of-a-kind application (startup in 2014) and smallest generating capacity (111 MW net).

- The proposed design and cost for SaskPower Shand – based on Boundary Dam experience – projects 65 percent lower capital requirement and similarly lower avoided CO_2 cost. The latter mostly is attributable to improved utilization of low-grade heat. The avoided cost of $45/tonne is calculated for a 30-year facility lifetime and 85 percent capacity factor.

- The NRG Petra Nova project initiated operation in 2016, three years after Boundary Dam Unit 3 started, and with more than twice the generating capacity. Petra Nova represents a 60 percent reduction in capital cost compared to Boundary Dam Unit 3, recognizing the latter as a first-of-a-kind incurred cost. The cost to avoid CO_2 per tonne is not publicly released for Petra Nova, but the implied (per discussion in Section 4) cost as $67/tonne and represents about a one-third reduction from Boundary Dam Unit 3.

Subsequent projects do not enjoy the same experience base. For example:

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[181] As noted previously, the DOE in October of 201 awarded three additional FEED studies for NGCC application. No further information about these projects or the anticipated completion dates are available at the time of this writing.

[182] For Golden Spread an “example” cost of $300 M is presented as a placeholder to derive an example payback calculation, but there is no justification or basis for this value. See Rochelle DOE/NETL CCUS August 2020 Review Webinar.

- The NPPD/Gerald Gentleman project cost is a preliminary Class 3 AACE estimate. A preliminary capital cost of $1,420/kW is reported and a cost to avoid CO_2 of $32.50/tonne. A capital recovery period of 20 years is employed in the analysis, but the capacity factor is not identified. A more detailed FEED cost study – developed to a "Class 2" AACE basis – was to be available in late 2021. Process design is based on a 12 MWe pilot plant rather than full-scale experience, thus scale-up risk must be considered.

- The Minnkota Power Cooperative Milton R. Young project, which extends application of the Fluor Econamine process to lignite coal, requires scale-up from the 10 MW Wilhelmshaven pilot plant.[183] The scale-up to this 450 MW net unit will benefit from Fluor's extensive experience in building acid gas scrubbing units for the petrochemical industry at approximately the same scale. A full suite of preliminary cost data has not been released, although an avoided cost estimate of $49/tonne is predicted.

- A FEED study addressing the Enchant Energy LLC San Juan Generating Station was to be completed by the end of 2021. This study utilizes a refined version of the MHI KM-CDR reagent based on experience at Petra Nova. A predecessor cost study for application of Fluor's Econamine process at this site estimated capital requirement of $2,150/kW and cost to avoid CO_2 of $42/tonne, based on an 85 percent capacity factor.[184]

- The NETL in 2018 estimated CCUS capital of $2,454/kW and $55/tonne to avoid CO_2 (based on an 85 percent capacity factor and 30-year plant lifetime for a 650net power output, 2017-vintage Cansolv process. Opportunities to lower this cost are sought through refinements of the Cansolv process, variants of MEA absorption, and other alternatives addressed for coal-fired retrofit.

9.3 Financial Incentives

9.3.1 Description of Credits

Several means are available to partially defray CCUS cost depending on project location. Domestic U.S. projects can qualify for federal incentives through Sections 45Q and 48A tax credits. The Elk Hills project defrays cost through three mechanisms - IRS 45Q tax credits, the California LCFS, and the California Cap-and-Trade program.

<u>Section 45Q</u>. This tax credit was initially authorized by the Bipartisan Budget Act of 2018 in February 2018. These 2018-era tax incentive provisions were further enabled by the 115th U.S. Congress FUTURE Act (S 1353) and the Carbon Capture Act (HR 3761).

Section 45Q incentives are available for power stations (and industrial facilities) based on the performance of CCUS equipment. Qualifying criteria include the installation date and utilization, and a minimum threshold of CO_2 tonnes removed. The owner of the power station or CCUS

[183] Reddy 2017 Econamine Update.

[184] The process lifetime for San Juan is not described; the study employs a capital recovery factor of 0.1243.

process is designated as the recipient of the tax credits but these can be transferred to parties involved in the storage or utilization of captured CO_2. Absent the ability to transfer these credits, the Section 45Q incentives would have little to no effect on owners with little to no tax liability, either because they are exempt from tax or have reduced tax liabilities for other reasons. To qualify for these credits, construction must initiate prior to January 1, 2024. Credit can be claimed for up to 12 years starting on the initial service date. [185] These criteria – specifically the qualifying threshold of CO_2 capture, the construction start date, and the term over which credits can be collected – should be modified to assure support for broad CCUS. The Carbon Free Technology Initiative advises extending the qualifying threshold for construction through 2035, allowing the credits to be claimed for 20 years, and – as an option – an electricity production tax credit for NGCC application be adopted.[186] Additionally, the Growing Renewable Energy and Efficiency Now Act of 2021, H.R. 848, and the Clean Energy for America Act, S. 1289, would convert the Section 45Q credit into a refundable direct payment tax credit. This allows owners to receive the full Section 45Q credits without the need of transferring credits to project partners.

Table 9-1 presents an example schedule for tax credits for both geologic storage and EOR. It starts in the first year of authorization of the predecessor (2018) legislation and runs through the year 2026, with subsequent values determined by inflation.[187] The credits initiate at $28/tonne for geologic sequestration and $17/tonne for EOR in the "kick-off" year of 2018. These tax incentives increase to $50 and $45, respectively, in 2026. Beyond that period they are adjusted for inflation. The specific impact of how these credits reduce the cost to avoid CO_2 ($/tonne) depends on the details of project financing and cannot be generalized.

Table 9-1. Schedule for 45Q Tax Credits: Sequestration, EOR

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2026+
Geologic Storage	28	31	34	36	39	42	45	47	50	Per inflation
EOR	17	19	22	24	26	28	31	33	35	

The credits as defined in Table 9-1 are available for 12 years following project initiation with the final two years established by inflation index.

<u>Section 48A</u>. In 2008, Congress extended the Energy Tax Incentives Act (ETIA) to provide an investment tax credit of 30 percent of eligible equipment to upgrade coal-fuel power plants to meet a prescribed thermal efficiency standard, and capture and store at least 65 percent of CO_2 emissions. While a coal-fired plant with CCUS cannot meet the thermal efficiency standard typical of a NGCC facility, achieving 90 percent CO_2 capture could potentially meet the criteria for CO_2 tonnes removed. The Section 48A tax credit currently contains $2.55 billion for qualifying coal projects. As of 2015, the IRS had allocated only $508 M of these tax credits. As an example, Section 48A tax credits could provide $130 million (undiscounted) for installing CO_2 capture at a 400 MW NGCC facility. For a regulated electric company subject to traditional

[185] Esposito, R.A., Electrical Utility Perspectives on CO_2 Geologic Storage and 45Q Tax Credits, A&WMA Mega Virtual Symposium, November 17-18, 2020. Hereafter Esposito 2020.
[186] See: https://www.carbonfreetech.org/Documents/CFTI%20Carbon%20Capture%20--%20Summary%20Paper.pdf.
[187] Ibid. Graphic 15.

cost-of-service accounting, the benefits of the tax credit need to be recognized over the life of the asset. Assuming a discount rate of 7 percent, the present value of the Section 48A investment tax credit (recognized over 30 years) is $57 M. This credit can be a complementary incentive to the Section 45Q incentive.[188] However, because the credit is not transferable nor available as a direct payment tax credit, it provides no incentive to owners with little to no tax liability.

Applicability to CCUS could be limited without changes to qualifying criteria for these credits, initially adopted to support thermal efficiency improvements in coal-fired generating units. The Energy Futures Initiative opines that CCUS-equipped units will be limited in accessing funds without update of applicability criteria.[189]

<u>California Low Carbon Fuels Standard (LCFS).</u> The LCFS is intended to reduce the carbon intensity (CI) of transportation fuels used in California, targeting a reduction of 20 percent by 2030 from a 2010 baseline. A refinery or ethanol fuel process owner employing CCUS to reduce the carbon intensity of transportation fuels in California can derive a tradeable credit. Applying CCUS to production of gasoline can reduce the life-cycle carbon intensity, measured by the well-to-wheel CO_2 equivalent metric (CO_2e/MJ). For example, CCUS can reduce carbon intensity as described by this metric for gasoline from 92 gms CO_2e/MJ to 63 gms CO_2e/MJ.[190] The reduction in carbon credits – valued in 2Q 2021 at approximately $170/tonne to $190/tonne – can be sold into the LCFS market.

The use of CCUS at Elk Hills is projected to reduce "… in half the lifecycle greenhouse gas emissions of the oil produced …,"[191] thus earning carbon intensity credits. Projects located outside of CA that deploy CCUS in an analogous manner can earn credits apportioned by the amount of fuel that is sold in CA.

<u>California Cap-and-Trade</u>. This program for California-based owners proscribes a declining "cap" on major sources of GHG emissions. Approximately 80 percent of the State's GHG emissions are covered in this program. Almost half are contributed by electricity providers or distributors. The CARB creates allowances equal to one metric tonne of CO_2e, based on the 100-year global warming potential. Allowances assigned each year are reduced to lower the cap. The floor price for allowances is increased each year to generate a consistent carbon price to encourage actions to reduce emissions.

The Elk Hills project can employ CO_2 credits derived from CCUS to augment LCFS and Section 45Q CO_2 credits.

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[188] Esposito 2021.

[189] *Building to Net Zero: A U.S. Policy Blueprint for Gigatons–Scale CO_2 Transport and Storage Infrastructure*, prepared by the Energy Futures Initiative, June 30, 2021. Available at https://energyfuturesinitiative.org/efi-reports. See page 53.

[190] The well-to-wheel reduction in carbon intensity with CCUS is calculated per the CA-GREET and GTAP models. Once quantifying the credits earned, the project owner is required to surrenders 8-16.4% to CARB to create a "buffer" account, with the remainder eligible for sale the LCFS Credit Clearance Market. See https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf.

[191] See: https://crc.com/images/documents/publications/CRC_CarbonCaptureStorage_Infographic_2020.pdf.

9.3.2 Impact on Cost

Section 45Q tax credits can significantly offset CCUS cost. Table 9-2 reports one example cited in the literature[192] describing the cost offset, and the previously described extension would further compensate most CCUS cost. Additionally, converting the credit into a refundable direct payment tax credit would ensure that all owners would be able to benefit directly and without incentive discounting that occurs in most tax credit transfer transactions.

Table 9-2. Section 45Q Tax Credit to CCUS: NG/CC, Pulverized Coal Application

Reference Unit	Required Capital Cost ($M)	Section 45Q: 12 Years		Section 45Q Extended	
		Annual Revenue ($M)	NPV ($M)	Extension (Yrs)	NPV ($M)
NGCC: 400 MW (net)	500-510	40	340	8 (Total 20)	460
Pulverized Coal: 400 MW (net)	1,200- 1,300	130	1,100	6 (Total 18)	1,300

NGCC. The NGCC example in Table 9-2 (400 MW net) requires capital cost like that projected by DOE/NETL for a similar unit of approximately $1,550/kW. The CCUS capital requirement is approximately $500 M to 510 M, exclusive of transport and sequestration. Transport and sequestration costs in the DOE/NETL studies are not projected as a capital cost but assumed equivalent to $3.50/MWh. An average annual revenue from Section 45Q credits of $40 M translates into a net present value of $340 M, offsetting 66 percent of the $510 M capital required. This offset can be increased to 90 percent of the required capital ($460 M of $510 M) by extending the credits for an additional eight years.

Pulverized Coal. The pulverized coal example shown (400 MW net) requires capital cost similar to that projected by NETL for a similar unit of approximately $2,454/kW. The CCUS capital requirement is approximately $1,200 M to $1,300 M, exclusive of transportation and sequestration. An average value of annual revenue from Section 45Q credits of $130 M translates into a net present value of $1,100 M, offsetting 85 percent of the $1,300 M capital charge. This offset can be increased to 100 percent of required capital by utilizing the same Section 45Q structure but extending the credits for an additional six years.

For both these NGCC and pulverized coal examples, additional capital can be required if a dedicated CO_2 pipeline is necessary. The average cost for the pipelines described in Table 5-2 – excluding the highest and least cost as outliers – is approximately $100 M.

The value of the offsets will vary with each unit, site, and operating conditions. Minnkota Power Cooperative has stated for the CCUS project at the Milton R. Young Generating Station that Section 45Q tax credits "finance the project without increasing member electricity rates."[193]

[192] Esposito 2020.
[193] Pfau, August 2020 Webinar.

The value of both Section 48A and CA LCFS are highly dependent on specific characteristics of a project and cannot be generalized.

9.4 Installed Cost Takeaways

- CCUS capital requirements in terms of $/kW (net) basis decrease significantly with increasing unit generating capacity (per Figure 9-1). Improvements in both absorption process design and solvents – the latter featuring higher CO_2 absorption capacity and faster kinetics – will contribute to minimizing equipment size and residence time.

- Application to large generating capacity units will exploit economies of scale and lower capital cost. Conventional engineering economics suggests equipment of this class be described by scaling to the 1/3 power, meaning doubling the size of the process increases cost not by a factor of two but 1.6.

- Further advancements in solvents – as observed for the Fluor Econamine and MHI KM-CDR with successive applications, and as proposed by Ion Clean Energy and the University of Texas at Austin with Honeywell/UOP – improve CO_2 carrying capacity and absorption kinetics, contributing to lower energy penalty to capture CO_2.

- One example alternative CO_2 capture process – membrane separation as developed by MTR – is represented in the FEED projects for which detailed costs will be determined. The membrane process exchanges the regeneration energy penalty for a gas pressure drop penalty, but presents alternate means to reduce cost via improved membrane design.

Experience gained from evolution of FGD emission controls over the last four decades is informative as we consider how costs for CCUS will evolve. Process simplification and scale-up lowered the cost of equipment for wet conventional FGD over several decades. The earliest FGD design employed multiple small reactors filled with packed beds for enhanced mass transfer and incurred operating problems due to an incomplete understanding of process chemistry. The latest state-of-art FGD designs benefit from improved understanding of process chemistry and performance enhancing additives. That enables simplified "open spray" towers that process as much as 800 MW to 1000 MW.[194] Consequently, process equipment cost decreased considerably and reliability improved.

DOE has established a cost target of $30/tonne. Achieving this goal is a possibility if the projected reductions in cost and increase in CO_2 capture performance can be attained. Continued and expanded funding of large-scale projects and seeking alternative technologies as described in the Section 5 *Evolving CO_2 Capture Processes* is critical to maximizing the possibility of success.

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[194] See: https://www.power-eng.com/news/looking-for-a-good-scrubbing-todayrsquos-fgd-technology/#gref.

Attachment B

United States Senate
WASHINGTON, DC 20510

June 30, 2023

The Honorable Willie L. Phillips
Chairman

The Honorable James Danly
Commissioner

The Honorable Allison Clements
Commissioner

The Honorable Mark C. Christie
Commissioner

Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Dear Chairman Phillips and Commissioners:

Last month, the Environmental Protection Agency ("EPA") published a proposal that would regulate greenhouse gases from our nation's fossil-fueled power plants in the *Federal Register* ("Proposed Clean Power Plan 2.0.")[1] The proposal presents unjustifiable claims about the future availability of technologies – including carbon capture, clean hydrogen, and the related infrastructure – used to power our electric grids. In light of recent testimony before Congress and the projected impact of the Proposed Clean Power Plan 2.0, we ask you to convene as soon as possible a series of technical conferences to assess the potential impact of the proposed rule on electric reliability. It is important that you act promptly as the EPA has already denied reasonable requests for a 60-day extension of the comment deadline;[2] EPA granted only a 15-day extension, and the comment deadline is now August 8, 2023.[3]

As each of you has readily acknowledged, Congress directly charged the Federal Energy Regulatory Commission ("FERC" or "the Commission") in the Federal Power Act with protecting electric reliability through mandatory reliability standards. More generally, Congress looks to the Commission to safeguard the quality of the nation's interstate electric and natural gas service.

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[1] *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33240 (May 23, 2023).

[2] *See*, *e.g.*, *ISO/RTO Council's Request for Extension of Comment Period*, EPA, EPA-HQ-OAR-2023-0072, filed June 8, 2023 (requesting 60-day extension of comment period).

[3] Extension of Comment Period for Clean Power Plan 2.0, 39 Fed. Reg. 39390 (June 16, 2023), https://www.govinfo.gov/content/pkg/FR-2023-06-16/pdf/2023-12834.pdf.

The Senate Committee on Energy and Natural Resources recently held two hearings that demonstrated the unprecedented and growing risks to electric reliability in the Unites States. In the first hearing, Chairman Phillips and Commissioners Danly and Christie outlined these risks. [4]

Commissioner Danly warned of "an impending, but avoidable, reliability crisis" caused by "public policies that are otherwise designed to promote the deployment of non-dispatchable wind and solar assets or to drive fossil-fuel generators out of business as quickly as possible." [5] Commissioner Christie explicitly warned about a "looming reliability crisis" if "the far too rapid subtraction of dispatchable resources, especially coal and gas" continues unabated.[6] Chairman Phillips said during the hearing that he is "extremely concerned when it comes to the pace of retirements that we are seeing of generators that we need for reliability on our system." He went on to say that "NERC and grid operators have warned about this . . . this is something that we have to keep a careful eye on."[7] As the Chairman explained, "[FERC is] resource neutral but [FERC is] not reliability neutral."[8]

In the second hearing,[9] the Chief Executive Officers of the North American Electric Reliability Corporation ("NERC"),[10] the Regional Transmission Organization PJM,[11] and one of America's largest electric cooperatives[12] also warned about increasing risks to the stability of the electric grids in the United States. When asked if they agreed with Commissioner Danly and Commissioner Christie's warning that the United States is heading for a reliability crisis, ***each said "I do***." These witnesses expressed the critical, consistent concern that the premature retirement of dispatchable generation is frequently driven by government actions, including rulemakings from the EPA. The Proposed Clean Power Plan 2.0[13] appears to pose a significant threat to the remaining dispatchable fleet when the nation can afford it least. ***All three witnesses*** also agreed that FERC and NERC should have input on rulemakings that may impact electric reliability.

When developing the original Clean Power Plan finalized in 2015, [14] the Obama administration itself stated that "comments from state, regional and federal reliability entities, power companies and others, as well as consultation with the Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC), helped inform a number of changes made in [the] final rule to

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[4] Full Committee Hearing to Conduct Oversight of FERC, May 4, 2023.
[5] Hearing Testimony from FERC Leadership including: 1. The Honorable Willie L. Phillips, Chairman, 2. The Honorable James Danly, Commissioner, 3. The Honorable Allison Clements, Commissioner, 4. The Honorable Mark C. Christie, Commissioner.
[6] *Id.*
[7] Full Committee Hearing to Conduct Oversight of FERC, May 4, 2023.
[8] *Id.*
[9] Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts, June 1, 2023.
[10] Testimony of James B. Robb, President and CEO, NERC. Robb Testimony.
[11] Testimony of Manu Asthana, President and CEO, PJM Interconnection. Asthana Testimony.
[12] Testimony of David J. Tudor, Chief Executive Officer, Associated Electric Cooperative Inc., Tudor Testimony.
[13] The Clean Power Plan 2.0 Proposed Rule includes five separate proposed actions. *See* 88 Fed. Reg. 33240 (May 23, 2023).
[14] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64874 (Oct. 23, 2015), https://www.govinfo.gov/content/pkg/FR-2015-10-23/pdf/2015-22842.pdf (hereinafter "Clean Power Plan").

address reliability"[15] At that time, EPA acknowledged that its consultations with FERC were "particularly important in shaping some provisions in these final guidelines."[16]

In 2014 and 2015, the Commission "held four technical conferences to discuss implications of compliance approaches to the rule for electric reliability."[17] These included "one national and three regional technical conferences on the proposed rule in which the EPA participated and at which the issue of reliability was raised by numerous participants."[18] All conferences were attended both by EPA leadership and staff, with "EPA leadership [speaking] at all of them."[19]

The already-strong pressure for premature retirements of electric generating units coupled with the rising risks to electric reliability require you to convene representatives of entities subject to your jurisdiction and other interested parties in order to develop a record on the potential impact of the Clean Power Plan 2.0. Without such a record, FERC's consultations with EPA are likely to be ineffective. EPA clearly lacks the expertise to project accurately the impact of its rulemaking on electric reliability without deeply informed and engaged participation from FERC and those subject to its jurisdiction that are charged with the obligation to generate and deliver electricity in order to meet continuous demand for electric service.

We ask that the Commission hold a series of technical conferences to analyze the impact of the Proposed Clean Power Plan 2.0 on electric reliability. Additionally, we request that any analysis or documents FERC and NERC provide to the EPA on the impact to electric reliability be shared with the Senate Committee on Energy and Natural Resources and the Senate Committee on Environment and Public Works.

Sincerely,

John Barrasso

John Barrasso, M.D.
Ranking Member
Committee on Energy and Natural Resources

Shelley Moore Capito

Shelley Moore Capito
Ranking Member
Committee on Environment and
Public Works

CC: The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency

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[15] *Id.* at 64874.
[16] *Id*. at 64672-64673.
[17] *Id.* at 64707. Each of the four technical conferences were entitled "Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure; Notice of Technical Conferences." These four conferences included: 1. National Overview, 79 Fed. Reg. 77001-77002 (Dec. 23, 2014), 2. Western Region, 80 Fed. Reg. 6073 (Feb. 4, 2015), 3. Eastern Region, 80 Fed. Reg. 9715 (Feb. 24, 2015), and 4. Central Region, 80 Fed. Reg. 12472 (Mar. 9, 2015).
[18] 80 Fed. Reg. at 64874.
[19] *Id.* at 64707.

Attachment C

Technical Comments on the

Carbon Capture Utilization and Sequestration Aspects of the Proposed

New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule

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August 7, 2023

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1 Summary

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. EPA bases the proposed GHG rule on many unverified assumptions, but the most egregious is that carbon capture utilization and storage (CCUS) is a demonstrated technology and qualifies as best system of emission reduction (BSER). EPA (improperly) designates CCUS as BSER, then extrapolates CCUS cost metrics to a wide variety of generating units. That EPA uses questionable means to generalize CCUS cost is of concern, but such concern is secondary to the unsubstantiated claim – and flaw in EPA's proposal - that CCUS is BSER. Consequently, all CCUS-related cost and performance predictions fail.

This critical observation, supplemented with several others, is further described as follows:

The CCUS Utility experience base is inadequate.

There is a single CCUS process operating in North America relevant to utility power generation—Sask Power Boundary Dam Unit 3. This unit has operated since 2014, and over eight years of refinement exhibits increased reliability– which although improved can still be compromised by failure of specialty, hard-to-acquire components that cannot be readily "spared" on-site.

A second CCUS operating unit relevant to utility power application – the Petra Nova "slipstream" project at the W.A. Parish station - operated for three years before termination in March of 2020. As further discussed in Section 3, both demonstrations were significantly co-funded by federal (and for Sask Power Boundary Dam) the local (provincial) governments.

This collective large-scale CCUS experience – comprised of two units with one operating for an abbreviated period – does not reflect the variety of conditions for CCUS application to the U.S. generating fleet. Of particular note is that small-scale pilot plant tests for two proposed demonstrations – conducted in 2015 (Minnkota Power Milton R. Young) and presently ongoing (Basin Electric Dry Fork) and are necessary to address remaining risk. The lean CCUS experience is in sharp contrast to real-world lessons accumulated in the early- and mid-70s with first-generation flue gas desulfurization (FGD) technology, in which 20 generating units were equipped with FGD and operated (some for five years) prior to a federal mandate to limit sulfur dioxide (SO_2) emissions.

Industrial CCUS applications are inadequate to reflect utility power generation.

EPA cites numerous industrial applications that due to scale, effluent gas treated, atypical CO_2 content and process conditions, limited removal of CO_2, or intermittent operation, are of peripheral import to coal-fired utility application. Consequently, experience with industrial applications has no impact on qualifying CCUS as utility-scale BSER.

Engineering "FEED" studies – regardless of the detail – do not deliver real-world operating experience, and are not a substitute for "lessons learned" from authentic operation.

EPA, lacking relevant CCUS experience, cites up to 15 engineering (Front-End Engineering Design, or FEED) studies as a basis for BSER. EPA's premise is invalid for two reasons. First, FEED studies do not address "final" design – the latter exercise a separate step, prior to equipment procurement. Second, and more important, FEED studies are exclusively paper and digital exercises that do not include the critical follow-through of building, operating, and documenting experience that almost without exception leads to revised design.

This view is shared by two contractors that supported EPA in this rulemaking. Sargent & Lundy Engineers (S&L) and Bechtel National Corporation state CCUS FEED studies leave risks that are not addressed. Specifically, EPA sponsored S&L to develop model CCUS cost calculations referenced in the Technical Support Documents, which state CCUS is an evolving technology. Bechtel, prime contractor for the FEED study addressing CCUS retrofit to the Panda/Sherman natural gas/combined cycle (NGCC) generating unit, state the present level of CCUS experience is inadequate; they recommend – prior to full-sale application at Panda/Sherman – a large capacity pilot plant test be conducted.

The CCUS cost basis – both capital requirement and the levelized cost per ton ($/ton) to avoid CO2 - is highly uncertain, and will remain so without additional large-scale demonstrations.

EPA attempts to compensate for the lack of experience by featuring paper and digital calculations, derived from unverified FEED studies, to determine the cost to avoid CO_2 ($/tonne).[1] The shortcomings for coal and NGCC applications differ, and are described separately.

<u>Coal Applications</u>. First, EPA – although citing FEED studies as a basis for BSER – ignore them as a source of capital cost for actual sites. Alternatively, EPA uses capital costs for a hypothetical unit, as determined by the National Energy Technology Laboratory (NETL) of the Department of Energy (DOE). A more authentic cost would be derived from the "average" of the six FEED studies – that even with uncertainty is "grounded" by actual site specifics. The difference in cost is not small - EPA's selected hypothetical unit capital cost is approximately 30% less than the average of the six FEED studies.

Conversely, EPA, when seeking estimates of cost to avoid CO_2 ($/tonne basis), changes course and features the FEED studies ignored for capital cost. EPA highlights FEED study results - along with several from international studies – to showcase that cost to avoid a tonne of CO_2 ($/tonne) cluster near the research and development (R&D) target of $40/tonne. As previously described, FEED results are paper and digital exercises, describing facilities never built or tested.

[1] All references to avoided cost are cited in terms of cost per metric tons ($/tonne).

Further, key factors that drive the levelized cost result – capacity factor and remaining unit lifetime – are not presented. EPA's reporting of these costs is not transparent.

NGCC Applications. Similar to the case for coal duty, EPA ignores FEED studies as a source for CCUS capital. EPA again defers to an NETL study of a hypothetical unit for capital cost – but not really, as EPA "discounts" the capital inferred. Specifically, EPA determines CCUS capital cost per net power output – the conventional metric - by normalizing the CCUS cost by net power *generated prior to CCUS*. This unusual combination – normalizing CCUS cost by net power *prior to retrofit* – is unprecedented, and ignores the loss of 33 MW consumed by CCUS. No explanation is offered for what is effectively a discount.

In summary – for both coal-fired and NGCC application – CCUS costs remains highly uncertain.

EPA's projected schedule for CCUS deployment – from concept evaluation to injection of CO_2 for sequestration or enhanced oil recovery – is unrealistic and compressed even compared to optimistic projects.

EPA ignores schedules to retrofit CCUS issued by two sources: the contractor S&L whom they engaged for this purpose, and the Global CCS Institute. S&L developed for EPA a CCUS retrofit schedule describing 6.25-7 years as necessary, and concede this applies to a partial scope of duties by ignoring CO_2 transportation (e.g. pipeline construction and permitting) and terrestrial sequestration (e.g. site development and permitting). The Global CCS Institute cites almost nine years as necessary, but "pass" on realistic permitting challenges – by noting their schedule assumes "…. there is no significant community opposition" to the project. Experience in the U.S. particularly the Midwest – belies this assumption.

EPA assumes the responsibility of completing the schedule. EPA adds activities to S&L's scope but compress the schedule by about two years. The resulting five-year schedule – slightly more than half of the 8.25 years advised by the Global CCS Institute - allocates one half-year to for CO_2 "transport and storage" feasibility and two years for CO_2 sequestration "site characterization and permitting." These estimates are contrary to plentiful evidence such timeframes are not credible. Section 5 describes how acquiring a CO_2 pipeline permit – such as the proposed Navigator project in Iowa - appears to require 3.5 years and only if no other roadblocks emerge prior to end-of-year 2024. Section 6 summarizes detailed schedules developed for the FEED studies and show under ideal conditions – a "head-start" for sequestration site development and no barriers to CO2 pipelines – eight years are required. Some projects will require possibly 12 years.

These studies suggest not only that the five-year time frame is unrealistic, with 10 years or more required for many projects.

CCUS does not qualify as BSER.

EPA is to select BSER after considering if a technology is "adequately demonstrated", "commercially available," and can be deployed for a cost that is "reasonable", all while representing the best balance of economic, environmental, and energy considerations. Two utility demonstrations – both with significant government cofunding – do not comprise an adequate demonstration. Process equipment for CCUS can be purchased – but without meaningful guarantees from process supplier, the technology is not fully commercially available. Costs, projected mostly from paper and digital FEED studies, are highly uncertain.

CCUS is distinguished from all precedent environmental controls in that a significant fraction of power produced that would be directed to the grid – 20-30% for coal- and 10% for NGCC-application – is consumed by the process. This collection of conditions does not qualify CCUS as BSER in the present state of development.

2 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. New Source Performance Standards (NSPS) for stationary combustion turbines and coal-fired generating units to limit emissions of CO_2 are proposed, as well such limits for existing fossil fuel generating units fired by coal, or gas turbines operating in simple or combined cycle duty.

Of the elements of EPA's proposed regulation, there is one critical premise – the role EPA assigns to carbon capture utilization and storage (CCUS). EPA submits that CCUS – in the present state-of-art technology –is commercially proven and feasible for utility application to both coal-fired and natural gas combined cycle (NGCC) generating units. EPA projects via its Integrated Planning Model (IPM) that 39 coal-fired power plants – totaling almost 14 gigawatts (GW) of capacity – will adopt CCUS by 2030.[2] The premise of EPA's modeling results in arbitrarily determining that CCUS is the best system of emissions reduction (BSER).

This report addresses the technology status of CCUS in terms of designation as BSER. The operating experience to underpin future applications of CCUS technology is reviewed, considering commercial-scale duty, laboratory tests, and the paper or digital design studies funded by the National Energy Technology Laboratory (NETL) and others.

This report is comprised of seven sections and two appendices. Section 3 addresses the shortcomings with industrial experience and Front-End Engineering and Design (FEED) studies, the features of emerging technology, and the limited experience with two units equipped with CCUS. Section 4 reviews EPA's evaluation of CCUS cost, addressing capital required and the levelized cost to avoid CO_2 on a dollar per metric tonne basis ($/tonne), including the impact of tax benefits accrued through the Inflation Reduction Act (IRA). Section 5 highlights one aspect of CCUS EPA does not address in detail – the task of securing CO_2 pipelines for delivery to sites for sequestration or use for enhanced oil recovery (EOR). Section 6 addresses EPA's assumption that a five-year deployment schedule is realistic. Section 7 projects on a continental map of North America the locations of EPA projected CCUS applications, showing the relationship to existing and proposed CO_2 pipeline routing and potential geological sequestration or EOR sites. Select backup material is presented in Appendices A and B.

[2] U.S. EPA, *Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket* (EPA_HQ_OAR_2023_0072), July 7, 2023. Hereafter EPA 2023 Integrated Baseline Analysis.

3 CCUS EXPERIENCE RELEVANT TO BSER

The EPA has designated CCUS as BSER based on the following rationale:

The technology has been studied, examined, and tested for decades and it has reached a point in its development where it is adequately demonstrated and commercially available.[3]

The additional economic incentives are important for establishing that the cost of CCS is reasonable, and an appropriate BSER.[4]

Section 3 reviews the technical basis of CCUS, focusing on relevant utility power generation experience, considering the definition of technology as adequately demonstrated and commercially available, and the incurred cost.

It should be noted EPA does not propose criteria by which to gauge CCUS in terms of the metrics "adequately demonstrated", "commercially available", and a cost that is "reasonable", and "appropriate." Nor does EPA address the decision to select a technology with the "best" balance of economic, environmental, and energy considerations.

3.1 Criteria for "Adequately Demonstrated"

A technology is considered "demonstrated" when there is (a) adequate experience that reflects projected operating duty, (b) confidence that operation is reliable over extended periods of time, and (c) the technology suppliers can *offer meaningful guarantees,* more than equipment and engineering services for sale. EPA in several instances distorts the meaning of the term "demonstrated". Most notable are (a) application at industrial or small-scale processes, and (b) the significance of engineering studies, the latter without corroborating results. These are described as follows:

3.1.1 Industrial Applications

EPA submit that industrial application of CCUS – particularly for cases that "report" 90% CO_2 capture – contribute to demonstrating CCUS for utility applications.

Industrial applications significantly differ from utility-scale power generation. Utility applications are distinguished by continual 24 x 7 duty, operation at high reliability, and processing flue gas with CO_2 content that differs from utility power generation – the latter typically 3-4% CO_2 for NGCC application and 11-13% CO_2 content for coal-fired application. Almost all non-utility applications treat product gases with higher CO_2 concentrations – such as

[3] Greenhouse Gas Mitigation Measures for Steam Generating Units – Technical Support Document. Docket EPA-HQ-OAR-2023-0072. Page 35. Hereafter Steam EGU TSD.
[4] Ibid.

chemical and ethanol production, and processing of hydrogen and ammonia, by up to a factor of 10. These high concentrations of CO_2 elevate the "driving force" for mass transfer and adsorption, which combined with a smaller scale and shorter physical distance over which to effect mixing and CO_2 absorption present different challenges than for power generation.

EPA's industrial "reference applications" are not relevant to utility duty. Specifically, EPA claims CCUS viability is "*.... further corroborated by CO2 capture projects assisted by grants, loan guarantees, and Federal tax credits for "clean coal technology" authorized by the EPAct05. 80 FR 64541–42 (October 23, 2015)."*[5] EPA cite a compilation of 72 CCUS projects – demonstration tests, pilot plant test, CO_2 storage, and transport activities – as relevant supporting their assessment, per Excel file "Attachment_1",[6] of which only two treat the entirety of gas flow generated. These two facilities – the Searles Valley Minerals caustic soda plant and the Quest methane reformer – do not represent large-scale utility duty, nor is there evidence that CO_2 removal matched that proposed by EPA for 24x7 duty. Other sites referenced by EPA are the "slip stream" category of process testing for which CCUS reliability does not limit that of the host unit.[7] Two "slip-steam" tests cited in the "Attachment 1" reference file are discussed – the Bellingham Energy Center for NGCC duty, and the Petra Nova demonstration (discussed in Section 3.3).

The sites reported to process the entirety of product gas – Searles Valley Mineral and Quest – are further described as follows:

<u>Searles Valley Minerals.</u> Public information suggests CO_2 capture is either intermittent or derives CO_2 removal well below 90%. The Searles site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[8] The CO_2 removal capability is cited as 800 tons per day[9] which suggests relaxed duty. Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one "daytime" shift). These performance metrics are not adequate to qualify CCS as demonstrated technology.

<u>Quest.</u> The effluent from this methane reforming process does not reflect combustion products, as CO_2 content is elevated compared to utility application. Experience with CO_2 removal at highly elevated content – although contributing to general CCUS knowledge – is not a basis to designate CCUS as BSER for utility application.

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[5] Steam EGU TSD. Page 22.

[6] EPA-HQ-OAR-2023-0072-0061_attachment_1.

[7] Three additional facilities are listed as operating CO2 capture, but as a "slipstream'. (AES Warrior Run, AES Shady Point, and Bellingham Energy Center). The slipstream process arrangement – a useful means for research and development - does not link the reliability of the host process to the CO_2 capture technology – and thus cannot represent conditions for 24x7 utility power generation demonstration.

[8] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.

[9] Elmoudir, W. et. al., *HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA*, Energy Procedia 63 (2): 6156-6165, December 2014.

Bellingham Energy Center. This NGCC unit is host to a 40 MW slip-stream employing a first-generation amine-based process (that evolved as the Flour Econoamine process). There is no data available to describe these results – a DOE "fact sheet" reports the unit operated from 1991 through 2005, with CO_2 removal of "85-95%".[10] It is not known if operation was continual versus intermittent, pending market demand for commercial grade CO_2. If periods of 85-95% CO_2 removal are interspersed with lower targets, this experience does not support BSER for utility application.

In summary, experience with industrial CCUS applications, although contributing to CCUS technology evolution, does not qualify CCUS as demonstrated for utility duty.

3.1.2 Engineering FEED Studies

EPA claims studies of CCS feasibility for utility duty – "Front End Engineered Design" or FEED studies – contribute to designating the technology as "demonstrated".

Three phases of analysis are typically employed to develop a CO_2 capture design. The first step defines the overall features of the design, using general site information, and "budgetary" cost quotations. This "pre-FEED" study presents a feasibility "yes/no" test.

The second step – the FEED study – is intended to (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the largest components to the site. At present, there are 13 such complete FEED studies (listed in Section 5) addressing coal-fired and NGCC generators.

The third phase is detailed engineering which specifies equipment physical attributes, layout, and an operating plan in detail to develop a request for proposal and solicit a supplier "firm" designs and cost. This detailed engineering step has been completed only for the Sask Power Boundary Dam 3 and the Petra Nova projects. For developed technology, this third phase should solicit performance and/or reliability guarantee from equipment suppliers.

EPA cite four FEED studies for coal and three for NGCC,[11] with seven more planned described in Attachment _1.[12] EPA rightfully identifies these FEED studies as "…projects in the early stages of assessing the merits of retrofitting coal steam EGUs with CCS technology", with potential for "…the application of CCS to existing gas facilities".[13]

[10] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.
[11] Steam EGU TSD. P. 23.
[12] EPA-HQ-OAR-2023-0072-0061_attachment_1.
[13] Steam EGU TSD. P. 23.

As will be shown for several projects, there remain significant "post-FEED" details in design and specifications for procurement. Most importantly, FEED studies as paper and digital exercises are absent the critically important "learning by doing" – the frequently quoted guidance from the Global CCS Institute as necessary to evolve CCUS.[14]

Four FEED studies are cited in the Steam EGU TSD for coal-fired duty: Basin Electric Dry Fork, Prairie State Generating Station, the Milton R. Young Station of Minnkota Power, and Nebraska Public Power District's Gerald Gentleman Station. Each of these studies is complete and project CCUS capital cost, and with assumptions of unit lifetime and capacity factor project an implied cost to avoid CO_2 ($/tonne). Capital cost results from these projects – in addition to analogous studies addressing Enchant Energy San Juan and Sask Power's Shand station – are addressed in Section 4.

Four newly launched studies have not progressed to delivering cost estimates. These are Cleco Brame Energy Center Madison Unit 3 (pet coke/bit coal) (Lena, LA); Duke Energy's Edwardsport integrated gasification combined cycle (IGCC) facility (Edwardsport, IN); Four Corners Station (located on the Navajo Nation in AZ); and CWL&P Dallman Unit 4 (Springfield, IL).

FEED studies are important - but on their own – are inadequate to qualify a technology as commercial. In at least two instances, FEED study authors advised additional pilot plant testing.

Basin Electric Dry Fork Coal-Fired. A 2020 FEED study by S&L evaluated MTR's membrane CO_2 capture technology for application to the Basin Electric Dry Fork station, and had advised the next phase of activities a 10 MW "large" pilot plant test,[15] evolving to a "slip stream" configuration for "partial capture conditions" at 400 MW capacity. This advisement offered in 2020 is testament to the evolving nature of CCUS technology.

NGCC Combined Cycle. A FEED study conducted by Bechtel National examined retrofit of a generic monoethanolamine (MEA) process to the 758 MW Panda Sherman Power Project. The principal investigators noted: *"At the time of this FEED study, no full-scale NGCC power plants with PCC was built anywhere in the world; even pilot studies using NGCC flue gas conditions were limited. This leads to a lack of data for process simulation model validation under conditions of interest for commercial NGCC+PCC plants…."*.[16]

[14] Technology Readiness and Cost for CCS, Global CCS Institute, March 2021. Available at https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/.
[15] Freeman, B. et. al., Commercial-Scale FEED Study for MTR's Membrane CO2 Capture Process, presentation to the Carbon Capture Front End Engineering Design Studies and CarbonSafe 2020 Integrated Review Webinar, August 17-19, 2020. P. 23.
[16] Elliot, W.R. et. al., *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines),* Final Scientific/Technical Report, DE-FE0031848, March, 2022. P. 2. Hereafter Panda Sherman 2022 Final Report.

The principal investigator then concludes: *"A pilot testing program is therefore proposed to resolve most of these design uncertainties, generally duplicating all process elements of the full-scale PCC unit apart from CO2 product compression."*[17]

This is S&L's second advisement that CCUS is emerging technology – in addition to recommending a pilot plant test at Dry Fork prior to commercial demonstration, S&L describe the technology as "emerging" in an explanatory note issued with the proposed CCUS schedule.[18]

FEED Studies are critical to project development for CCS as this technology is an emerging technology with very limited full-scale / commercial installations.

In summary, FEED studies develop the arrangement of process equipment and preliminary cost for CCUS. These conceptual exercises are inadequate to qualify CCUS as BSER.

3.2 Stages of Emerging Technology

Commercially available technologies are characterized by operating experience that enables process suppliers to provide meaningful performance guarantees.

As noted by S&L, CCS is considered an "emerging technology"[19] which typically evolve in several stages. Early projects are based on limited experience and the role of process suppliers evolved during this period. It must be emphasized there is stark contrast between a supplier offering "for sale" an engineered design and fabricated hardware, in contrast to providing meaningful process guarantees. This subsection further addresses these topics.

3.2.1 First, Nth-of-a-Kind

Any new process – or application of an evolving process to conditions outside present-day experience – is considered the "first" of a "kind" (FOAK). Such FOAK designs are characterized by uncertainty in terms of equipment arrangement, process conditions (reaction chemistry, flow field, temperature), and operating duty, and the risk to achieve environmental control performance and reliability.

FOAK designs can address risk and uncertainty but only by large scale testing and operation for extended periods. Projects subsequent to FOAK are described as the "Nth-of-a-Kind" (NOAK), in which additional (the nth) application addresses evolving conditions. There is no clear delineation between the number of FOAK applications necessary to evolve to NOAK.

Power industry technologies are not considered "demonstrated" until adequate "NOAK" applications operate for sufficient time, defining and resolving uncertainties. There is no broadly recognized threshold for the number of acceptable NOAK projects to be completed prior to

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[17] Ibid.
[18] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.
[19] Ibid.

commercial maturity. The DOE acknowledges this uncertainty with regard to CCUS, in noting NOAK designs can include equipment that "…. are not fully mature (e.g. plants with IGCC and any plant with CO_2 capture…", and will incur costs higher than reflected within their most recent analysis.[20]

The fact that CCUS is a FOAK or NOAK is evidenced by the demonstrations at the Basin Electric Dry Fork and Minnkota Power Milton R. Young station. As described in Section 6, the site-specific process design for these sites relies heavily on pilot plant tests – either completed (in 2015) or presently underway – at the site. The uncertainties which remain are best addressed at pilot scale which is proof CCUS technology is not mature.

The uncertainty of FOAK designs is also recognized in the Princeton "Net-Zero" study.[21] The analysis suggests five FOAK designs must be built and operated for – in their opinion – sufficient time for costs to "settle"; but with broader implications for mitigating risk.

3.2.2 Commercially Availability

EPA implies CCUS processes are commercially available when suppliers offer to sell the necessary process equipment and engineering services. However, a supplier offering to design, procure and install such hardware does not constitute commercial availability. The missing requirement is meaningful guarantees of process performance, backed with remedial action if goals for emissions removal or reliability are not attained.

Neither Sask Power or Petra Nova process hardware were reported as awarded performance guarantees. That absence of commercial guarantees is the reason both projects were significantly co-funded by federal and local governmental entities, with additional funds defraying risk inherent to a FOAK concept.

3.3 North American Utility Scale Processes

At present, there is one operating CCUS unit in North America from which to assess commercial feasibility – Sask Power Boundary Dam Unit 3. A second CCUS-equipped unit – Petra Nova – operated for 3 years (terminating in March 2020). Both of these demonstrations provide significant experience – but on their own does not establish CCUS as demonstrated and commercially available.

A summary of these two projects is presented in this subsection.

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[20] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL – 2023/4320, October 14, 2022. Hereafter 2020 Baseline CCUS Costs. P.50
[21] The Princeton Net-Zero Project - *Potential Pathways, Infrastructure, and Impacts.* Available at https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200

3.3.1 Sask Power Boundary Dam 3

Overview. Sask Power has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv CO_2 process. Inherent to the Cansolv process is a SO_2 removal step – controlling SO_2 to less than 10 parts per million (ppm) – that combined with improved particulate matter control protects the amine sorbent from degradation.

This activity was significantly co-funded by the Canadian and Saskatchewan provincial governments. The capital budget is approximately $1.2 B (USD), of which $240 M is provided by the Canadian and provincial government. The retrofit of CCUS was contemporaneous with refurbishing the steam turbine and the electric power generator to support 30-year operation.

CO_2 Disposition. CO_2 is compressed to 2,500 pounds per square inch gauge (psig) and transported 70 kilometers (km) by pipeline to the Weyburn oilfield for EOR, where it is injected 1.7 km underground. CO_2 not employed for EOR is transported 2 km for sequestration in the Deadwood saline aquifer (referred to as Aquistore).

As the Steam EGU TSD notes, a key issue is protecting the amine sorbent from decay with exposure to trace metals and SO_2. Several issues not unique to CCUS process equipment have compromised reliability. EPA note CCUS reliability was compromised in 2Q 2021 due to a failed CO_2 compressor but dismiss this as not inherent to CCUS reliability. However, Sask Power cites these large, special purpose components as rare, and due to limited inventory are not immediately accessible. The cost to maintain "spares" on site is prohibitive. To assure high reliability, additional capital cost should be allocated to provide access to spare equipment; alternatively, enhanced operation and maintenance (O&M) should be planned and include downtime for "preventive" maintenance.

Observations are offered for Sask Power Boundary Dam 3 in three categories: reliability, cost of CO_2 capture ($/tonne), and implementation schedule.

Reliability. The availability of the Boundary Dam 3 CCUS facility is publicly reported in the Sask Power's CCUS Blog.[22] This latter source reports the reliability separately of the host boiler and CCUS process since Q1 2021. Figure 3-1 presents two quarterly reports that describe reliability continuously from Q1 2020 through Q1 2023 (available as of July 24, 2023). The top portion of each chart reports Boundary Dam Unit 3 availability (white background) and the lower portion of each chart reports CCS facility availability (gray background).

Considering CCS facility alone, Figure 3-1 shows the average of availability from Q2 2021 through Q1 2023 is 64.5% over this period. The loss of the compressor is a major contributor to this shortfall and a factor to be encountered in commercial duty.

[22] https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q1-2023.

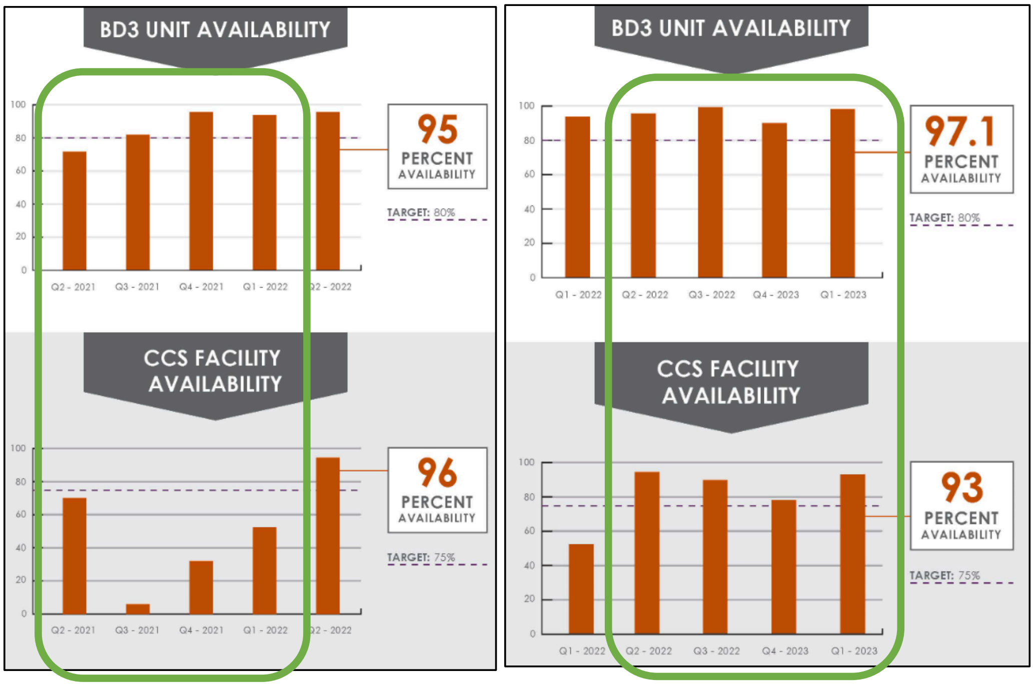

Figure 3-1. Reliability of Boundary Dam Unit 3, CCS Process: Q1 2021 to Q1 2023

Cost. As a FOAK retrofit, Boundary Dam 3 cost although not representative is informative. As previously described, capital cost (including plant refurbishment was of $1.2 B (U.S, 2014-dollar basis),[23] with the Canadian government contributing $240 M.[24]

Sask Power report 50 percent of the cost is attributable to the CO_2 capture and regeneration process, 30 percent for power plant refurbishment, and 20 percent for other emissions control and other efficiency upgrades.[25] Consequently, $600 M of capital is accounted for CCUS, equivalent to $5,405/kW $_{\text{(net, w/CCUS)}}$.

The levelized cost to avoid one tonne of CO_2, as reported by the CCS Knowledge Center, is $105. This cost estimate is based on a capacity factor of 85 percent, lifetime of 30 years, and a credit for CO_2 as EOR.[26] It should be noted CCUS availability since 1Q 2021 has prevented this cost of $105/tonne from being achieved.

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[23] https://financialpost.com/commodities/energy/jim-prentice-to-wind-down-carbon-capture-fund-in-alberta-new-projects-on-hold?. Canadian dollar values at 0.86 USD in 2014.
[24] See: https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.
[25] Giannaris et. al. 2021.
[26] *The Shand CCS Feasibility Study Public Report*, November 2018, CCS Knowledge Center. Available at https://ccsknowledge.com/initiatives/2nd-generation-ccs---Shand-study. Hereafter Shand 2018 Feasibility Report.

Schedule. Sask Power does not report schedule details from concept inception to delivering CO_2 for EOR, but reports the project took six years from "…commitment to completion".[27] Given the proximity to both an existing oil field (Weyburn) and saline reservoir (~10 mile) the actions to acquire permits – not reported by Sask Power – are likely atypical for most of the U.S. domestic fleet.

Sask Power's schedule may be relevant only for units situated in oil producing regions. Considering the cost subsidy, the reliability issues, and the incurred cost of CO_2 control, Boundary Dam 3 experience does not represent CCUS as "adequately demonstrated" or "commercially available."

3.3.2 Petra Nova

Overview. NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. This process employed the second-generation KM-CDR solvent developed by MHI and Kansai Electric Power Company, previously tested at 25 MW scale at Alabama Power Company's Barry Station.

The Petra Nova demonstration, significantly co-funded by the U.S. DOE, required capital of approximately $1 B. The CCUS process is not applied to the entirety of Unit 3 flue gas, but rather a 240 MW-equivalent slipstream, thus not affecting host unit reliability. Petra Nova's CCUS process hardware is unique – a 78 MW gas turbine (GE 7FA) was installed with a heat recovery steam generator (HRSG), the latter the source for CCUS auxiliary steam. The power generated by the gas turbine not consumed by the CCUS process (reported as 35 MW) is sold to the energy grid.[28]

CO_2 Disposition. CO_2 upon regeneration is compressed to 1,900 psig and transported 81 miles by pipeline for EOR at the West Ranch site, requiring injection between 5,000 feet to 6,000 feet underground. Unlike Boundary Dam Unit 3, there is no alternative means of CO_2 disposition.

Similar to Boundary Dam Unit 3, numerous operating issues were encountered with ancillary components. Heat exchangers processing reagent denoted as cool lean (without CO_2) and hot rich (with CO_2) were prone to leaks, while the gas quencher accumulated deposits that restricted performance. Some issues are attributed to penetration of SO_2 entering the capture process. These components are necessary for CCUS, and their failure should not be dismissed as incidental. In the third operating year, additional factors such as tube corrosion in the solvent reclaimer were encountered that – similar to Sask Power – can compromise CO_2 compressor performance.

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[27] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.

[28] W.A. Parish Post-Combustion CO_2 Capture and Sequestration: Demonstration Project DOE Award Number DE-FE0003311 Final Scientific/Technical Report, Report DOE-PNPH-03311, March 31, 2020. Hereafter Petra Nova 2020 Final Report.

Observations are offered for the Petra Nova project in three categories: Reliability, cost of CO_2 capture ($/), and implementation schedule.

Reliability. CCS reliability increased each year. Considering both the CO_2 capture system and the source of auxiliary steam, in the last operating year (2019) 49 days were fully or partially lost. Although an improvement from the 108 observed in 2017, the CCUS process was still not available for 13.4% of operating time in the third and best year.

Cost. Petra Nova reports a $1B capital cost with approximately 60% expended for the CO_2 capture equipment, gas turbine, and the HRSG – the latter to provide auxiliary steam. The remaining approximately 40% of the cost was dedicated to administrative matters, the share of the CO_2 pipeline, and improvements to the oil field to enable higher CO_2 injection for EOR. Funding sources were a DOE grant of $190 M, financing of $250 M, and equity offered by the sponsors. One trade journal noted Petra Nova financing conditions were unique: "Like other early CCS demonstration projects, Petra Nova's financial viability relied on a rare alignment of incentives, including a DOE grant, cheap credit from Japan, and part-ownership of an oilfield, which probably has limited relevance for future CCS plans under the new fiscal policy."[29]

The project sponsors are not forthcoming with actual incurred cost per tonne ($/tonne). The final report to DOE[30] does not address this cost metric. The EPA in the Steam EGU TSD cite a cost of $65/tonne, as referenced to the Global CCS Institute,[31] whom in turn cite a Petra Nova Technical Report from a period (July 2014 through December 2016) prior to unit operation.[32] Consequently, the $65/tonne is a pre-operational estimate, no different than a FEED evaluation, for which basic parameters of unit lifetime and capacity factor are not shared. Also, project economics should account for the incremental revenue derived from the 35 MW delivered by the gas turbine (acquired under the CCUS budget) to the grid. (This revenue could lower CCUS levelized cost, but no details are provided.

Schedule. Petra Nova required a 6-year schedule for their activities, with work initiating in early 2011 to enable an air permit to be filed in September 2011,[33] although details are absent in the public schedule.[34] Petra Nova is unique as the Texas Gulf Coast provides an ideal location for CCUS given existing pipeline corridors and proximity of oilfields that can readily accept significant CO_2 injection.

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[29] https://www.nsenergybusiness.com/features/petra-nova-carbon-capture-project/#.
[30] Petra Nova 2020 Final Report.
[31] Technology Readiness and Costs of CCS, March 2021, the Global CCS Institute. See page 35.
[32] W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report/Final Public Design Report, Award No. DE-FE0003311, for July 01, 2014 to December 31, 2016. See page 30.
[33] Ibid. P. 13.
[34] *Petra Nova Carbon Capture*, presented to the Carbon Capture, Utilization and Storage, and Oil and Gas Technologies Integrated Annual Review Meeting, August, 2019. Graphic 3. Available at: https://netl.doe.gov/sites/default/files/netl-file/Anthony-Petra-Nova-Pittsburgh-Final.pdf.

The Petra Nova project schedule may be relevant only for units situated in oil producing locales. Considering the cost subsidy required, and complicated by reluctance to release the final costs, the Petra Nova project – although contributing to CCUS technology development - does not qualify CCUS as BSER.

4 REVIEW OF EPA's PROJECTION OF CCUS COST

4.1 Overview

Section 4 critiques EPA's cost evaluation of CCUS. As noted in Section 3, there are only two verified capital cost reports for CCUS –Sask Power Boundary Dam Unit 3 and Petra Nova. EPA's proposed trajectory of CCUS evolution more optimistic compared to that observed for flue gas desulfurization (FGD) technology, in which multiple demonstration tests (many <100 MW) operated for up to 5 years prior to federal legislation mandating FGD deployment. Further, EPA is inconsistent in their selection of references – after lauding FEED studies that EPA submits demonstrate the technology as commercial – EPA ignores these results when seeking capital cost. Finally, EPA does not consider the risk to reliability presented by CCUS, that compromises CO_2 removed and tax benefits accrued through the IRA.

These are further described as follows.

4.2 Inadequate Experience for Cost Basis

There is little verified experience with CCUS to base EPA's estimate of cost. In contrast, FGD evolved through approximately 20 commercial-scale processes that provided significant experience at utility conditions, prior to federal legislation mandating their use.

Figure 4-1 presents for FGD technology the installation date and flue gas equivalent generating capacity treated for installations through mid-1978. It should be noted that 20 FGD installations were installed and operating prior to the 1977 Clean Air Act Amendments - with at least 10 operating for up to five years.[35] This experience served as the basis to mandate the use of FGD.[36]

Figure 4-1 shows that – prior to 1977 and drafting of the Clean Air Act Amendments in that year – FGD technology evolved in a logical manner. The first three years (through 1975) saw 10 installations, of which all but three were of 150 MW of capacity or less. Notably, three installations that exceeded 400 MW in capacity were an early design variant – the "combined particulate/SO_2" process – which incurred either reliability or SO_2 removal challenges. These combined particulate/SO_2 processes – almost without exception – required refurbishment or replacement with "conventional" limestone FGD technology.

[35] Shattuck, D. et. al., *A History of Flue Gas Desulfurization (FGD) – The Early Years*. Available at https://www.science.gov/topicpages/g/gas+desulphurization+fgd.
[36] Aldy, J. E. et. al., *Looking Back at Fifty Years of the Clean Air Act*, Resources for the Future Report 20-01 October 2020, Revised December 2020. Available at: https://media.rff.org/documents/WP_20-01_rev._Looking_Back_at_Fifty_Years_of_the_Clean_Air_Act_hmvW55y.pdf.

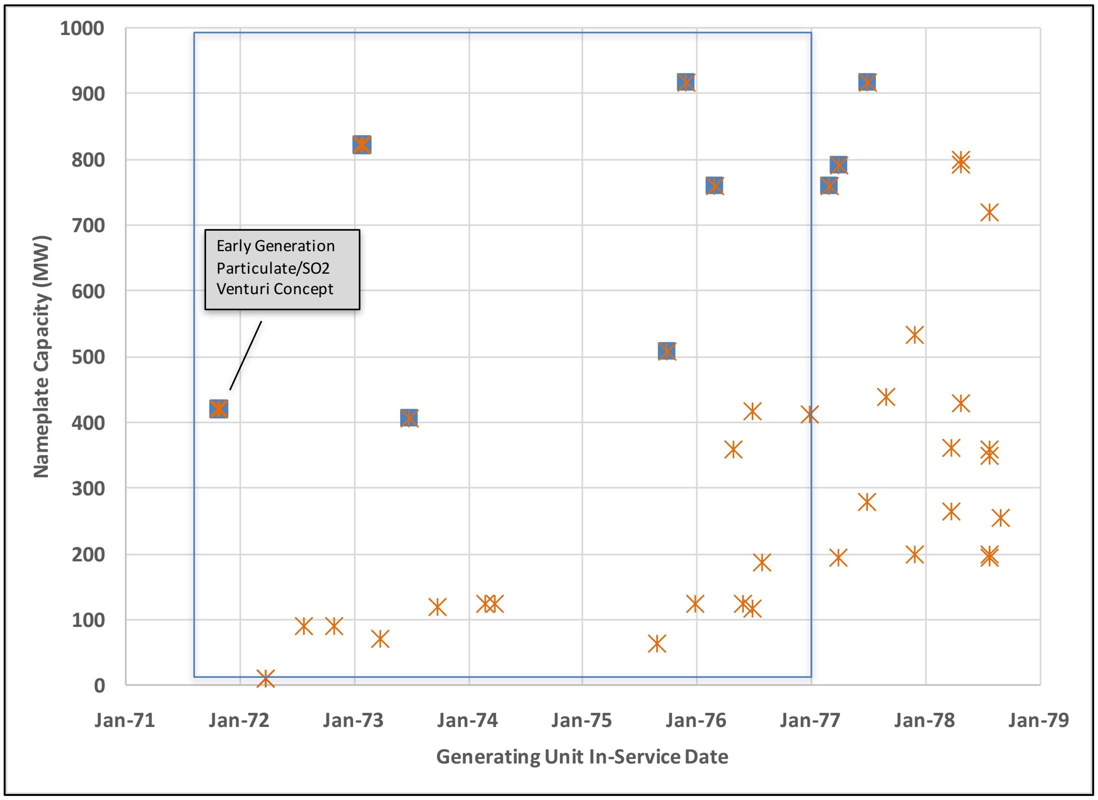

Figure 4-1. Evolution of Wet FGD Technology: The First Decade

In summary, compared to the status of FGD technology at the time of federal legislation mandating use, CCUS at present is characterized by inadequate experience, affecting cost and reliability. Consequently, CCUS experience is inadequate to base federal regulation for CO_2 removal at the scope and timescale as proposed.

4.3 FEED Study Capital Cost

EPA, after lauding FEED studies to justify CCUS as BSER, ignores FEED results when seeking a realistic capital cost for use in their analysis of avoided CO_2 cost ($/tonne). FEED studies provide a better estimate of CCUS capital cost then EPA's use of a hypothetical "model" plant.

As described in Section 3, FEED studies are the second step of a three-phase process to develop engineering details for a CCUS design. Even with six FEED results "in-hand", EPA uses an S&L "model" to generate CCUS capital cost for a "hypothetical" unit, reporting results in Table 7 of the Steam EGU TSD. Of note are three S&L's disclaimers in the source document describing the limits in the use of the model to generate costs.[37] These address scope, site factors, and the lack of a cost "benchmark" – as described as follows:

[37] IPM Model – Updates to Cost and Performance for APC Technologies: CO_2 Reduction Retrofit Cost Development Methodology, Final Report, Project 13527-002, March, 2023. Hereafter S&L 2023 CO_2 IPM.

Scope:

Transportation, storage, and monitoring (TS&M) of the captured CO_2 are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

Site Factors:

The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions.

Cost "Benchmark" or Validation:

Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions.[38]

These disclaimers are clear – scope is not complete and terminates with CO_2 at the fence line; site factors are ignored; and results are not validated with experience. Consequently, cost estimates for CCUS capital and the levelized cost to avoid CO_2 ($/tonne) are at-risk. An alternative approach is to use FEED site specific results and adopt the average capital cost.

4.3.1 Coal-Fired Applications

Figure 4-2 presents CCUS capital cost *per net generating capacity after CCUS* for the two demonstrations and the six FEED studies for coal-fired generating units. Capital cost is reported for Sask Power Boundary Dam 3,[39] Sask Power Shand,[40] Petra Nova,[41] Basin Electric Dry Fork,[42] Minnkota Milton R. Young,[43] Enchant Energy San Juan,[44] Nebraska Public Power

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[38] S&L 2023 CO_2 IPM at p. 1.

[39] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.

[40] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.

[41] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, Petra Nova Parish Holdings LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.

[42] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane CO_2 Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.

[43] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.

[44] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.

District Gerald Gentleman,[45] and Prairie State.[46] Figure 4-2 also reports capital cost for one of the hypothetical unit evaluated by NETL: 640 MW (net) with a 10,000 Btu/kwh gross heat rate.[47]

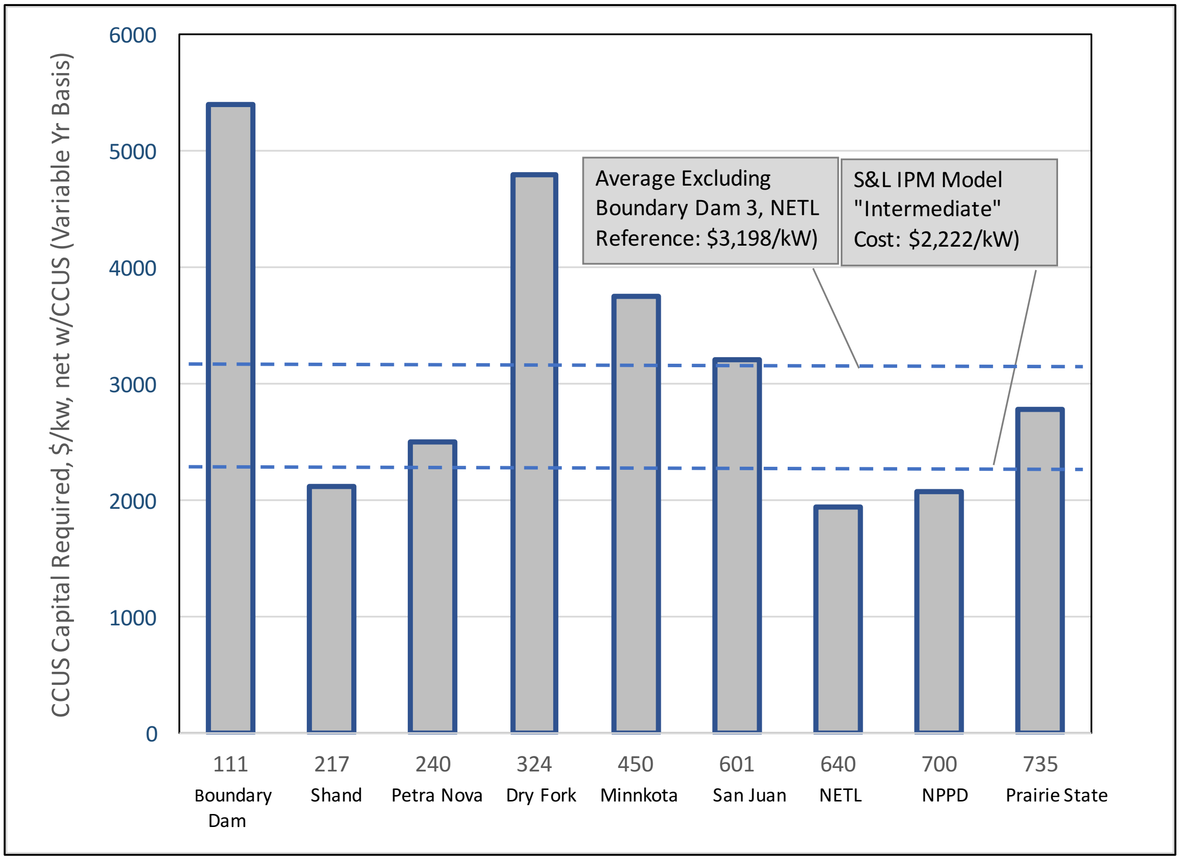

Figure 4-2. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 4-2 displays the capital cost from one of EPA's "reference" units (Table 4 of the Steam EGU TSD) used to calculate levelized cost to avoid CO_2 ($/tonne). This calculation, using the S&L IPM model, is conducted for a 400 MW plant with a 10,000 Btu/kWh heat rate, approximating the average conditions of generating capacity and heat rate of units in Figure 4-2. The CCUS capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$ for this reference unit is superimposed on the figure as a reference point for Figure 4-2 results.

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[45] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.

[46] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.

[47] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

Data in Figure 4-2 vary widely by site. Capital cost *per net generating capacity after CCUS* determined by the FEED studies for all but two units exceeds the \$2,222/kW $_{\text{(net, with CCUS)}}$ derived using the S&L IPM procedure for the reference 400 MW unit. The average capital cost from these FEED studies and demonstration tests – excluding the highest and lowest values – provides a more authentic estimate of CCUS capital cost.

Excluding both the highest (Boundary Dam) and lowest (NPPD) costs reported in Figure 4-2, the average capital cost of units in Figure 4-2 is \$3,198/kW $_{\text{(net, with CCUS);}}$ a 44% increase to S&L's reference unit. These FEED study results, even though not "benchmarked" to actual data, are transparent and can be reviewed – unlike costs generated by the S&L IPM model, which include "proprietary data".[48]

It is important to recognize capital cost data in Figure 4-2 reflects only CO_2 capture, compression, and preparation for transport from the fence line – but not for transport to the sequestration or EOR site, injection, and plume monitoring.

Sites requiring minimal pipeline length still incur significant costs for the sequestration step. Two example sites for which information is available are the Minnkota Power and Petra Nova projects.

<u>Minnkota Power's Milton R. Young Station</u>. This site requires only 0.5 mile of pipeline for CO_2 transport to the sequestration site. However, additional facilities are required for substations for CO_2 metering and pumps, monitoring for seismic activity, and plume migration. The injection of CO_2 requires four wells drilled – three for injection and one for subsurface monitoring – to as deep as 10,000 feet. Environmental monitoring instrumentation as required for Underground Injection Control (UIC) Class VI wells is included to assure successful sequestration, as well as financial assurance in accordance with the regulatory requirements of UIC Class VI wells. These ancillary support facilities and provisions are estimated to require an additional \$100M – or, \$289/kW $_{\text{(net, after CCUS)}}$.

<u>Petra Nova</u>. Section 3.3.2 reports of the \$1B for all activities, \$600 M was devoted to CO_2 capture at the plant site with the remaining \$400 million dedicated to, among other needs, the CO_2 transport and upgrade of the West Ranch site. This includes the cost for the 81-mile CO_2 pipeline and for upgrading the oilfield wells to accept more CO_2 for EOR. As a transparent accounting of projects costs has not been released, it is not known how much of the \$400 M is dedicated to these activities.

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[48] S&L 2023 CO_2 IPM, page 3. "Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor."

4.3.2 NGCC Applications

Figure 4-3 presents capital cost estimated by FEED studies of NGCC assets that have been reported in the public domain. These FEED studies address the Panda Sherman,[49] Golden Spread Mustang,[50] Daniel 4,[51] and Elk Hills[52] generating units.

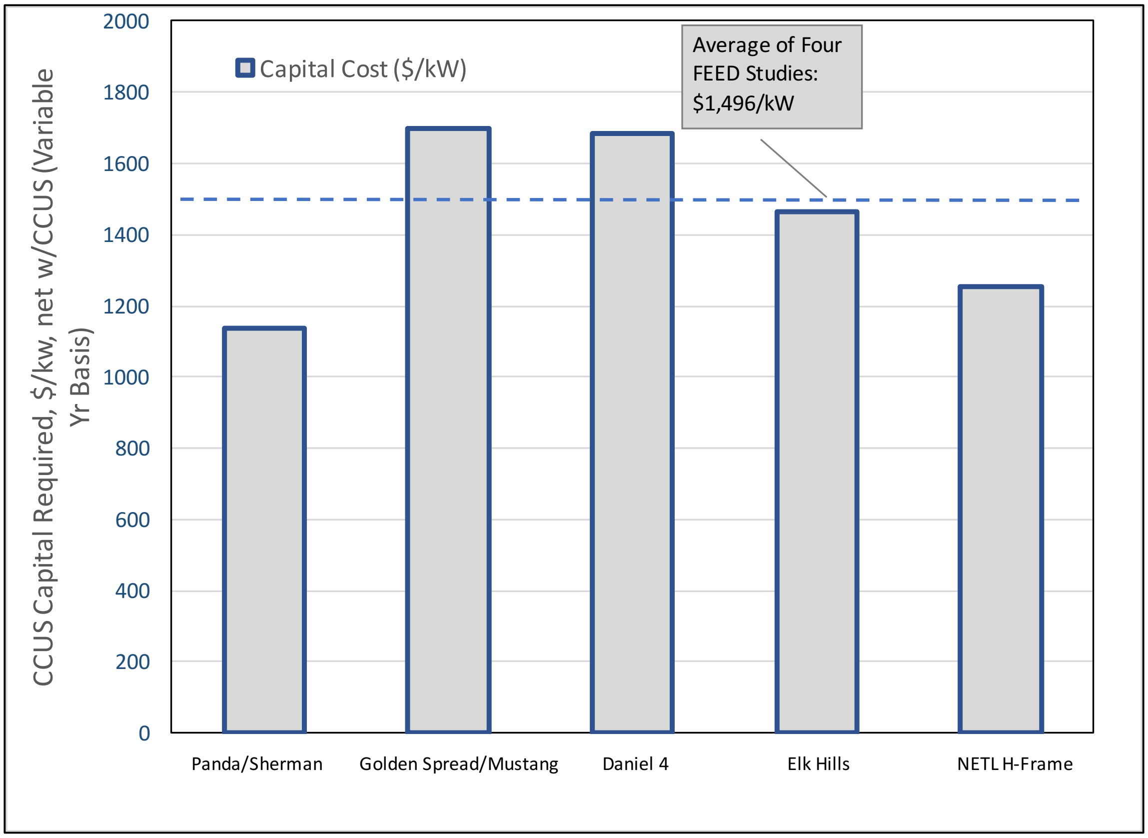

Figure 4-3. CCUS Capital Cost as Reported for NGCC FEED Studies

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[49] Panda Sherman 2022 Final Report.

[50] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study, DE-FE0031844, 2022 Carbon Management Research Project Review, August 17, 2022.

[51] Lunsford, L., et. al., *Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant,* Final Scientific/Technical Report, per DE FE0031847, September 30, 2022. Hereafter 2022 Daniel FEED Report.

[52] *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant*, Agreement DE-FE0031842, for US DOE/NETL, January 2022. Hereafter 2022 Elk Hills FEED Report.

Figure 4-3 also includes CCUS capital for retrofit to hypothetical NGCC units, as evaluated by NETL.[53] The NETL study estimates capital cost F-Frame and H-Frame gas turbine designations. The H-Frame result is shown in Figure 4-3 for CCUS capital cost, reported as $/kW $_{\text{(net, with CCUS)}}$.

Capital costs reported in Figure 4-3 vary widely by site, driven by, among other factors, the steam source for CCUS. For example, CCUS capital cost projected for Panda Sherman ($1,135/$/kW $_{\text{(net, with CCUS)}}$ is the lowest as the existing HRSG provides steam CCUS duty – but at the cost of a capacity penalty. Conversely, the highest capital cost (~$1,700/$/kW $_{\text{(net, with CCUS)}}$) is estimated for two units (Mustang, Daniel 4) as project scope includes auxiliary boilers to provide steam, preserving generating capacity.

The average of the four FEED studies – albeit representing different concepts to provide CCUS steam –is $1,496/$/kW $_{\text{(net, with CCUS)}}$. This value represents a 20% premium to the cost developed by NETL.

4.4 Inadequate Basis for Levelized $/Tonne Calculation

EPA employs different methodologies to calculate the levelized cost to avoid CO_2 ($/tonne), including the impact of the IRA, for coal-fired and NGCC generating units. For coal, EPA's calculations are recorded in the docket[54] but NGCC calculations are inadequately explained or referenced.

EPA's calculation methodology is reviewed in this section to document shortcomings. However, as stated previously, CCUS is not BSER and cost are not confidently defined; thus, EPA's calculations are speculative and do not reflect present state-of-art in the proposed rulemaking docket.

4.4.1 Coal-fired Application

EPA calculations presented in Table 8 of the Steam EGU TSD, which defined levelized cost per (short) ton including the benefits of the IRA, are invalid for numerous reasons. First, as noted in Section 4.3.1., the capital cost used by EPA for this calculation is derived from the S&L IPM model, for "hypothetical" sites. As noted in Section 4.3.1, this source does not provide capital cost "referenced" to a specific site, nor based on fully transparent data. The example 400 MW unit with a 10,000 Btu/kWh heat rate is assigned a cost of $2,222/$/kW $_{\text{(net, with CCUS)}}$ 31% less than capital from FEED studies ($3,198/$/kW $_{\text{(net, with CCUS)}}$).

Second, calculations are based on the optimistic premise that the CCUS process will operate at 100% availability, thus always be available to accrue tax benefits and defray operating cost. As the bulk of CCUS costs are capital, incurred whether the unit is operating or not, periods of

[53] *Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3*, DOE/NETL-2023/3848, May 31, 2023. Hereafter 2023 NGCC CCUS Retrofit.
[54] EPA-HQ-OAR-2023_0072-0061_attachment_3.

restricted duty will limit CO_2 delivered and tax benefits. A compromise in availability directly affects the calculated cost to avoid CO_2.

Table 4-1 compares the levelized cost per tonne ($/tonne) for EPA's optimistic case, and two sensitivity cases that explore the role of CCUS capital cost and process availability.[55] Table 4-1 presents EPA's results as calculated using Tables 8 and 9 Steam EGU assumptions, the "intermediate" capital cost ($2,222/kW $_{\text{(net, with CCUS)}}$, and perfect availability (100%). The costs are presented for 50% and 70% capacity factor, and include the benefit of the IRA.[56] Also shown are results to sensitivity analysis.

Table 4-1. Sensitivity Results: Role of Capital Cost, CCUS Reliability of Projected CO2 $/tonne

Capacity Factor (%)	EPA Assumption			FEED Study Average		
	Capital Cost ($/kW)	CCS Reliability	$/Tonne	Capital Cost ($/kW)	CCS Reliability	$/Tonne
50	2,222	100%	15	3,198	100	49
50	2,222	90	23	3,198	90	53
70	2,222	100	-9	3,198	100	15
70	2,222	90	-2	3,198	90	23

The sensitivity of the levelized cost (including IRA benefits) to avoided CO_2 ($/tonne) to changes in CCUS capital and reliability are described as follows:

<u>EPA Capital, Compromised CCUS Availability.</u> This case retains EPA's optimistic capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$, but recognizes that – as witnessed at Sask Power and Petra Nova - CCS availability is typically less than 100%. Results for the two capacity factors are as follows:

- Perfect (100%) Availability. Estimated $/tonne cost is reported as $15 at 50% and -$9 at 70% capacity factor.
- Compromised (90%) Availability. Estimated $/tonne costs elevates to $23 at 50% and - $2 at 70% capacity factor.

<u>FEED Study Capital, Compromised CCUS Availability</u>. Applying the average of FEED study capital of $3,198/kW $_{\text{(net, with CCUS)}}$ for 100% and 90% CCUS reliability derives the following:

- Perfect (100%) Availability. Estimated $/tonne costs elevates to $49 for at 50% and $15 at 70% capacity factor.

[55] It should be noted the author could not corroborate why Table 8 of the Steam EGU TSD specifies the variable O&M cost used in the calculation is $5/MWh, compared to $23/MWh reported by the S&L IPM source document for what appears to be comparable conditions. For the purpose of this report, calculations adopt EPA's $5/MWh to assure a valid comparison. However, the difference is noted and should be further explored.

[56] The "negative" costs presented in Table 4-1 for two cases reflect EPA's projection that CO_2 removal and sequestration will comprise a profitable venture.

- Compromised (90%) Availability. Estimated $/tonne costs elevates to $53 for at 50% and $23 at 70% capacity factor.

It should be noted that –without the IRA subsidy – the cost to avoid CO_2 per tonne for some cases is a factor of 10 higher compared to 100% CCUS reliability. For capital cost of $3,198/kW $_{\text{(net, with CCUS)}}$, the levelized cost to avoid CO_2 at 50% capacity factor is $127 and at 70% capacity factor is $93.

4.4.2 NGCC Application

As noted for coal-fired duty, CCUS for NGCC duty is not BSER. Both S&L and Bechtel have opined there is negligible experience with CCUS on NGCC conditions. EPA project CCUS capital cost for NGCC using an unconventional metric that biases costs low and extrapolate costs to a wide range of applications using both NGCC and coal-derived basis. These results are flawed, as described as follows.

Capital Cost. EPA projects CCUS capital cost using an incorrect metric. Table 7 of the Combustion Turbine TSD reports capital, fixed O&M, and variable O&M costs for hypothetical NGCC units employing the F-Frame and H-Frame technologies, as derived by NETL for "greenfield" application. Table 7 presents capital cost per net generating capacity (a) replicated from the NETL study[57] and (b) inferred by EPA.

The implied capital for CCUS depends on whether NETL's "conventional" method is chosen, or EPA's inexplicable variant. NETL's conventional method – taking the difference in capital cost with and without CCUS – implies a capital cost of $1,199/kW $_{\text{(net, with CCUS)}}$ for F-Frame and of $1,055/kW $_{\text{(net, with CCUS)}}$ for the H-Frame applications

EPA inexplicably changes the capital cost metric. The capital cost EPA attributes to CCUS in Table 7 –$949/kW for the F-Frame and $823/kW for the H-Frame – is lower than inferred from NETL's methodology, as EPA normalizes the inferred CCUS cost by net generating capacity prior to CCUS retrofit.[58] This approach is flawed as it does not account for 33 MW of net power consumed due to the CCUS process.

Extrapolation to Different Applications. EPA's Combustion Turbine GHG TSD employs a series of extrapolations to infer CCUS capital, fixed operating, and variable operating cost for a variety of combustion turbine applications.

EPA (a) misuses the power law relationships describing the change in equipment cost with generating capacity, and (b) fails to recognize the difference in CCUS process conditions

[57] 2022 Bituminous/NGCC CCUS Retrofit. Exhibit 9-5 at 710.
[58] Personal Communication, Lisa Thompson to Liz Williamson, July 25, 2023. *The $949/kW cost in Table 7 is calculated by dividing the absolute difference in the costs of the combined cycle EGU with CCS and without CCS divided by the net output of the combined cycle EGU without CCS. In this case, 688 million divided by 727,000 kW (rounded).*

between coal-fired vs NGCC duty. As a consequence, EPA projects CCUS cost for NGCC duty (3-4% CO_2) based on coal-fired duty (with 12% CO_2). Notably, a 2013 NETL report[59] cautions extrapolations such as these, which EPA follows to produce Figures 1-5 in the Combustion Turbine TSD.

In perspective, these EPA cost results are not of consequence as CCUS is not a demonstrated technology on NGCC (or coal-fired application), and a basis for cost extrapolations does not exist. The shortcomings in EPA's methodology are further discussed in Appendix A for reference.

In Summary:

- EPA estimates of CCUS capital cost for coal applications in Tables 6 and 7 of the Steam EGU TSD are low. The real-world source is the average capital cost derived from the two industrial demonstrations and FEED studies, eliminating the high (Boundary Dam 3) and lowest (NETL) cost units. These real-world projects define a cost of $3,198, a 43% premium to that generated by the IPM model. Revised estimates of $/tonne incurred – using FEED-study capital cost and accounting for a 10% compromise in CCS reliability - increases cost calculated for 50% capacity factor from $23 to $53/tonne with the IRA credit, and for 70% capacity factor from $2 to $23/tonne <u>*if CCUS works as planned for at least 12 years*</u>.

- EPA estimates of CCUS capital cost for NGCC application presented in the Combustion Turbine GHG Mitigation TSD are not transparent. EPA infers CCUS capital from a NGCC CCUS retrofit study issued May 28, 2023, in lieu of the more real-world approach of averaging cost from the four FEED studies. This latter approach derives capital cost exceeding that of the NETL-derived hypothetical site by 20%. Most notably, there are no applications of CCUS on NGCC units – thus no sources to verify the design from which cost is derived. Two EPA contractors agree. Specifically, both (a) S&L in reporting the projected CCUS schedule and IPM model and (b) Bechtel in the FEED study for Panda/Sherman both state limited experience with CCUS on NGCC brings uncertainties, which compromise the authenticity of any cost estimate.

[59] *Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology*, DOE/NETL-341/013113, January 2013. Hereafter 2013 Scaling Quality Guidelines.

5 CO2 Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in CO_2 pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. Section 5 presents examples of ongoing permitting conflicts, demonstrating how delays can be incurred. The takeaway from this discussion is used in the critique of the CCUS implementation schedule presented in Section 6.

5.1 Background

Deploying CCUS to numerous generating units – such as the 39 units EPA estimates to deploy per the 2023 Integrated Baseline Analysis - requires expanding CO_2 pipelines capability. One limiting step to CCUS deployment is acquiring the necessary right-of-way for pipelines to transport the CO_2. EPA in their projected CCUS schedule estimate 130 weeks to be required for permitting a pipeline. The Global CCS Institute assumes that in acquiring pipeline access during their proposed almost 9-year schedule "…. there is no significant community opposition." [60]

A key factor determinate in the schedule is the pipeline length to access either EOR or terrestrial sequestration. Each additional mile of pipeline requires additional owners' land to access and acquire right-of-way. Pipeline permitting issues are addressed following a brief discussion of pipeline length.

5.1.1 Pipeline Length

The length of the pipeline to transport CO_2 from candidate CCUS sites can vary by an order of magnitude. This range is evidenced by several units that have completed CCUS FEED studies. The CO_2 pipeline length for projects located adjacent to the generating site – such as for Project Tundra at the coal-fired Dry Fork station, and the Elk Hills NGCC application – are less than a few miles. Conversely, and as shown in Figure 5-1, the pipeline length necessary to transport CO_2 to the ECO2S Regional Storage Complex from Mississippi Power's Daniel Unit 4 is 180 miles and from Plant Miller 150 miles.[61] Although it appears desirable to rely on CCUS installations on units located at or adjacent to a disposition site, such a strategy is unrealistic as host units may not have favorable characteristics (generating capacity, capacity factor, remaining lifetime).

[60] CCS Institute report 20-22; p. 48.

[61] Riestenberg, D. et. al., Establishing an Early Carbon Dioxide Storage Complex in Kemper County, MI: Project EICO2S, 2020 DOE/NETL Integrated Review Webinar, August 17-19, 2020. Hereafter 2020 Kemper County Storage Complex.

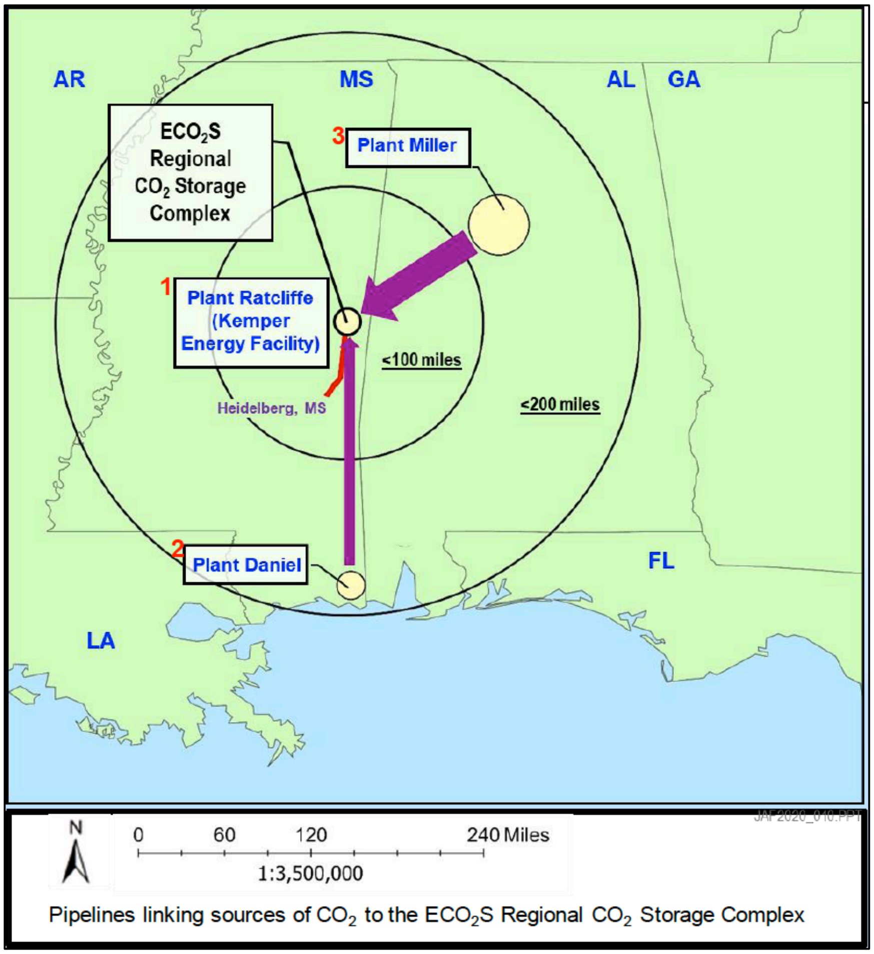

Figure 5-1. Candidate CO_2 Pipeline Routing, Length: Plants Daniel and Miller

Both the DOE and EPA adopt a typical pipeline length to be 100 km – 62 miles – for which there is no technical basis; EPA concedes this assumption as a means for "standardization".[62] The DOE applies this "default" 100 km pipeline length in their cost evaluation for "hypothetical" plant. EPA states "…. there are 43 States containing areas within 100 km from currently assessed onshore or offshore storage resources in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs";[63] this observation is inadequate to justify the 100-km length as a default.

Pipeline length will be driven by finding adequate storage volume to accept the CO_2 quantity from a large generating unit; it is unlikely the required storage will be located at the nearest boundary of any terrestrial basin. The NETL Atlas[64] - developed to provide "high-level" assessment and not a detailed assay of disposition sites - reveals significant heterogeneity of features that affect CO_2 injection rate and storage. The quantity of CO_2 to be stored for a coal-

[62] 88 Fed. Reg at 33,297, n 333.
[63] Ibid; 33,298.
[64] NETL Carbon Storage Atlas; Fifth Edition, DOE Office of Fossil Energy, August 2015. Hereafter 2015 DOE/NETL Storage Atlas.

fired or NGCC unit of generating capacity large enough for CCUS to be feasible (i.e., 400 MW or more) is far greater than demonstrated at all but a few sequestration sites permitted to date. The Global CCS Institute reports 22 projects either in operation or construction for 2024 or 2025 duty with only two sequestering 5 or more million tonnes of CO_2 per year (Mt/a).[65]

In summary, EPA's assumption of a 100-km average pipeline length to access an acceptable reservoir for power generation units is not substantiated.

Section 7 presents a graphic depicting arrangement of the 39 units projected by EPA to adopt CCUS, showing the "footprint" required for pipelines of 100 and 200 km.

5.1.2 Pipeline Projects: Select Description

The Midwest is the nexus for CO_2 pipeline permitting. Several entities are well into the process of developing pipelines to acquire CO_2 from ethanol facilities. The major actors are Summit/Midwest Carbon Solutions, Navigator, and Wolf Carbon. Key features of each project are summarized as follows:

- Navigator[66] proposes 900-mile pipeline bisecting Iowa from northwest to southeast and transporting CO_2 to Illinois. (~$3.2B). A total of 1,300 miles via South Dakota, Nebraska, Minnesota, in addition to Iowa, is proposed. The permit application was filed in July 2022.

- Wolf Carbon[67] propose 280 miles of pipeline to transport CO_2 from ADM ethanol producing facilities in eastern Iowa to Decatur, IL for terrestrial sequestration.

- Summit Carbon[68] will build 700 miles of pipeline in western and northern Iowa to transport CO_2 to North Dakota, for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[69]

These entities are pursuing pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state– Iowa presents perhaps the most structured "steps", and Nebraska the least. The lack of structured steps currently in Nebraska does not imply permitting requirements are less strict than Iowa; but that Nebraska's process for permitting CO_2 pipelines is evolving.

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[65] *Global Status of CCS 2022*, issued by the Global CCS Institute. Section 6.2. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/.
[66] https://heartlandgreenway.com/about-us/.
[67] https://wolfcarbonsolutions.com/mt-simon-hub/.
[68] https://summitcarbonsolutions.com/project-footprint/.
[69] *Proposed Iowa Pipeline Would Cross 30 Counties*, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/.

Landowners cite several reasons for resisting access to their property. One frequent reason cited is concern that agricultural productivity is compromised within the pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[70]

5.2 Permitting Experience

Both the EPA's and the Global CCS Institute's treatment of pipeline permitting is unrealistic. This section will report opposition encountered by "grass-roots" entities, with support from organizations such as the Eco-Justice Collaborative and the Sierra Club. These organizations, among others, promote campaigns to resist pipeline permits; in Illinois providing an on-line petition.[71]

Each state presents different barriers – and opportunities – to pipeline permitting and construction. Within each state, perhaps the most contentious issue is eminent domain – which a project developer can invoke if they argue the proposed pipeline is of "public use or public convenience and necessity." Success in this argument enables acquisition accompanied by fair compensation.

5.2.1 Iowa

CO_2 pipelines could be of paramount importance in Iowa, as ethanol production asserts significant financial impact on the state and is the major CO_2 source. A total of 57% of corn farmed in Iowa is processed for ethanol. Iowa is noteworthy in that pipeline permitting, design, and construction decisions are controlled by a governing body – the Iowa Utilities Board (IUB).[72] The permitting process consists of (a) sponsoring public information meetings in each county, (b) allowing developers 30 days after the public meetings to file a petition for a permit, and (c) establishing a schedule for public hearings, including pre-hearing filing dates for testimonies and exhibits. Upon completing these events, IUB can render a decision.

All three developers propose pipelines in Iowa – 830 miles by Navigator; 95 miles (eastern Iowa) by Wolf Carbon, and 2,000 miles (northern and western Iowa) by Summit. A total of 48% of pipeline length proposed by the Navigator and Summit project are in Iowa.

The numerous barriers to the pipeline pre-feasibility work and permitting in Iowa are summarized as follows:

<u>Survey Access</u>. Iowa law – as presently enacted - allows pipeline companies access to proposed easements for survey, with the requirement that informational meetings are sponsored, and

[70] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way.
[71] https://noillinoisco2pipelines.org/.
[72] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state.

landowners notified. The constitutionality of this law is being challenged by four property owners that refuse access the property.[73]

Denial of Right-of-Way. A total of 430 landowners are rejecting offers to sell right-of-way to CO_2 pipeline owners.

Eminent Domain. Pipeline developers can use eminent domain – at the discretion of the IUB – to build pipelines on the property of owners who refuse to voluntarily comply. Eminent domain decisions are made on an individual case-by-case basis. Resistance to eminent domain is strong - 78% of Iowans oppose it's use.[74]

A legal challenge to eminent domain is being considered in Iowa, as follow-on to earlier challenges introduced in 2015.[75] Iowa proposed a bill requiring pipeline developers to acquire right-of-way voluntarily from 90% of landowners prior to invoking eminent domain.[76] An additional challenge to eminent domain is based on rejecting the "public use" argument, despite the claimed CO_2 pipeline benefit of supporting ethanol production.

Approximately 30% of Summit's proposed pipeline route crosses 1,000 parcels of land – for which they have obtained 40% of the required voluntary easements[77] for the 680-mile segment in Iowa. The prospect for eminent domain is of great concern; media cite eminent domain "…." has the potential to elongate the final permit hearing, when eminent domain requests are individually considered.

Finally, some owners are adamant they will not participate:[78]

"When is 'no' accepted as 'no'? How many times do we have to say no? My answer in 2021 for an easement was 'no.' My answer today is 'no.' My answer tomorrow and any days forward will be a resounding 'no.' Our land is not for sale."

5.2.2 Nebraska

Nebraska is reported – at present –to not have established CO_2 permitting requirements; the lack of such requirements is not to be interpreted that Nebraska is – or will be – lenient. For example, in contrast to Iowa where pipeline developers can access sites (under preconditions) for survey, Nebraska has no such rule. Further, proposed legislation in Nebraska will require owners to remove CO_2 pipelines, once the project and CO_2 removal duty is complete. Finally, unlike other states, there is no option of eminent domain.

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[73] https://www.agriculture.com/news/business/judge-says-pipeline-survey-lawsuit-should-go-to-trial.
[74] https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed.
[75] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.
[76] https://www.agriculture.com/news/business/house-passes-bill-to-restrict-eminent-domain-for-pipeline
[77] https://www.agriculture.com/carbon-pipeline-opponents-decry-sham-process.
[78] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.

5.2.3 Illinois

Illinois presently hosts numerous studies of geologic sequestration to support the state's concentration of ethanol production sites. At present, there is a sole – and short – pipeline confined to the ADM ethanol facility in Decatur, routing CO_2 captured for on-site sequestration. However, some observers project Illinois could be a superhighway for CO_2 pipelines.[79] The responsibility for permitting pipelines is within the Illinois Commerce Commission (ICC).

Local resistance exists. McDonough County issued a two-year moratorium on pipeline approval and permitting actions, primarily to allow for improved federal safety design standards. Separately, a representative of the ICC noted that 14 separate permits for federal, state, and local permits are required for a pipeline, of which none had been acquired as of September 2022.[80]

5.3 Timeline Summary

The currently available timelines for the Summit and Navigator project are summarized as follows:

Navigator. This developer initiated public hearing in 4Q 2021, and as of early 2022 planned to start construction in 2024.

Wolf Carbon. Wolf files a pipeline permit in February of 2023 with the IUB and it is uncertain if construction could start in the second quarter of 2024.[81] Wolf reports the permit applications does not – at least to date – include a request to use eminent domain.

Summit. Summit filed an initial permit in August 2021 and – upon encountering delays - asked for a decision by the end-of-year of 2024. This timeline represents almost a 3.5-year duration.[82] The Sierra Club – who oppose the pipeline along with select landowners – propose the hearing be delayed to 2024. Summit is reported as of late May 2022 to have signed easements with approximately 30% of the landowners required to complete the pipeline within Iowa.[83]

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[79] Advocates urge Illinois landowners to prepare for risks from CO2 pipelines, March 15, 2022, Energy New Network. Available at https://energynews.us/2022/03/15/advocates-urge-illinois-landowners-to-prepare-for-risks-from-co2-pipelines/.

[80] Illinois County Offered Payments to Back Navigator Carbon Dioxide Pipeline, February 3, 2023, Energy New Network. Available at https://energynews.us/2023/02/03/illinois-county-offered-payments-to-back-navigator-carbon-dioxide-pipeline/.

[81] https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed.

[82] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.

[83] *Strange Bedfellows: Farmers and Big Green Square Off Against Biden and the GOP*, Politico, May 29, 2022. https://www.politico.com/news/2022/05/29/iowa-manchin-carbon-capture-pipeline-00030361.

One observer thinks at least 3 years will be required to resolve permit issues; dozens of lawsuits have been filed in Iowa, and North and South Dakota – most initiated by pipeline companies to secure access.[84]

Takeaway: The most evolved reference case for CO_2 pipeline permitting – activities for Summit within Iowa – at present project a 3.5-year timeframe from proposal to final hearing. Abiding by this schedule assumes the final hearing is conducted at end-of-year 2024. This projected timeframe exceeds all schedules project by EPA.

[84] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state.

6 CRITIQUE OF CCUS SCHEDULE

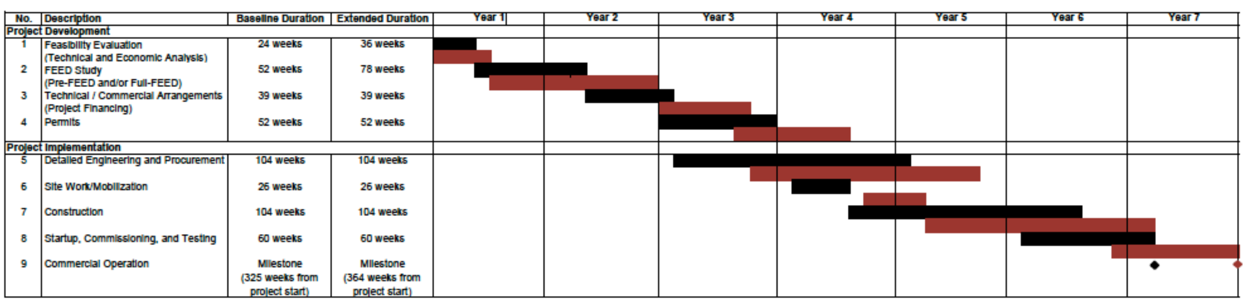
The EPA has proposed a five-year schedule to execute a CCUS project from concept through delivery of CO_2 for sequestration or EOR. Section 6 critiques EPA's proposal and demonstrates a 5-year duration is inadequate.

Eight demonstration projects or FEED studies represented in Figure 4-2, four delivered at least partial schedules. In addition, two FEED studies of CCUS to NGCC units illustrated in Figure 4-3 delivered partial schedules.

None of the proposed schedules support a five-year timeline for the complete scope to deploy CCUS, or seriously address permitting for sequestration or CO_2 pipelines, much less consider the timelines necessary to finance a CCUS project.

6.1 S&L Proposed Schedule

The EPA sponsored S&L to develop a CCUS schedule, from concept to delivering commercial quantities of CO_2 for disposition. Figure 6-1 presents the image of the schedule in the docket[85] describing a "baseline" duration of 6.25 years and an "extended" duration of seven years.



No.	Description	Baseline Duration	Extended Duration
Project Development			
1	Feasibility Evaluation (Technical and Economic Analysis)	24 weeks	36 weeks
2	FEED Study (Pre-FEED and/or Full-FEED)	52 weeks	78 weeks
3	Technical / Commercial Arrangements (Project Financing)	39 weeks	39 weeks
4	Permits	52 weeks	52 weeks
Project Implementation			
5	Detailed Engineering and Procurement	104 weeks	104 weeks
6	Site Work/Mobilization	26 weeks	26 weeks
7	Construction	104 weeks	104 weeks
8	Startup, Commissioning, and Testing	60 weeks	60 weeks
9	Commercial Operation	Milestone (325 weeks from project start)	Milestone (364 weeks from project start)

Figure 6-1. S&L CCS Deployment Schedule

S&L describes the scope of duties addressed in the schedule to include project development (feasibility assessment, FEED studies, developing commercial agreement and technical specifications, permitting, award of contracts) and implementation (detailed engineering, fabrication, construction, startup, commissioning, and testing).

S&L in their supporting material describe two barriers to this schedule, which EPA ignores in the Steam EGU TSD. These barriers are:

<u>Potential Impacts, Road Blocks.</u> S&L list seven potential "schedule impacts" than can impose a delay: equipment fabrication or delivery; weather, underground interferences; challenging site for retrofit; contract negotiations and financing; and – perhaps the largest – public comment

[85] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

periods. Example "roadblocks" or "bottlenecks" are a limited number of vendors and constructors for work of this scale; infrastructure of steel availability and heavy construction equipment; engineering due to large project volumes.

Incomplete Scope. S&L present a disclaimer stating the schedule addresses on-site activities, excluding those external to the site but critical for project execution.

This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO2 off-take / storage (including transportation, sequestration, enhanced oil recovery utilization, and/or utilization).

In summary, the S&L schedule does not reflect all activities required for a complete CCS project, and thus does not represent a realistic timeline.

6.2 Global CCS Institute Schedule

A CCUS schedule proposed by the Global CCS Institute - an organization funded by government entities, and suppliers of process equipment and engineering services - projects an almost 9-year timeline.[86] Figure 6-2 presents this schedule as extracted from the referenced Global Status of CCUS 2022 report.

The Global CCS Institute offers the following context – actually disclaimers – regarding their schedule:

- a large complex CCUS project may take a decade to progress from concept to operation;
- the necessary tenements and approvals for geological storage of CO_2 from regulators, generally requires years to complete; and
- The identification and appraisal of geological resources for the storage of CO_2 is a costly and time-consuming process. These activities typically take a few years to complete and are subject to the availability of geoscientists with appropriate experience and the critical equipment required to collect data and drill wells.[87]

The Global CCS Institute report does identify conditions where a shorter timeline is feasible; and such sites may exist. It is noteworthy EPA's assumption of five years for broad deployment is almost half of that projected by an organization whose objective is to promote CCUS.

[86] *Global Status of CCS 2022*, issued by the Global CCS Institute. P. 47. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/.
[87] Ibid. at pgs. 47-48.

FIGURE 28: SIMPLIFIED GANTT CHART FOR A COMPLEX CCS PROJECT

Figure 6-2. Global CCS Institute Deployment Schedule

6.3 EPA's Compressed Schedule

The schedule EPA presents in the Steam EGU TSD is a compressed version of the schedule developed by S&L. S&L does not consider the transport and disposition of CO_2 off-site within their timeline scope; EPA proposes a schedule for this task. EPA advises between one to two years are required for a sequestration site feasibility study, characterization, and permitting.[88] EPA cite as evidence source material that is not convincing or supportive: (a) site characterization and permitting for a 10 MW pilot plant – generating a small fraction of the CO_2 produced by a commercial plant, and that will operate for five years;[89] a management overview of the four phases of the CarbonSafe program (that total more than 5 years).[90] EPA's third example is experience of a project in North Dakota, a state with primacy, in securing a sequestration permit, but absent documentation of a final schedule certifying permits-in-hand (although cautioning "Pore space acquisition takes more time than you think".)[91] These citations do not support EPA's 104 week duration for site characterization and permitting that is included

[88] Steam EGU TSD. at 36.

[89] Large Pilot Testing of Linde-BASF Advanced Post-Combustion Carbon Dioxide Capture Technology at a Coal-Fired Power Plant. Available at https://www.netl.doe.gov/projects/project-information.aspx?k=FE0031581

[90] CarbonSafe Storage Assurance Facility Enterprise: Available at: https://netl.doe.gov/sites/default/files/2022-05/IG-CarbonSAFE_20220512.pdf

[91] Peck, W., North Dakota CarbonSafe Phase III: Site Characterization and Permitting, August 2, 2021, available at https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Peck.pdf

in their five-year schedule. Similarly, no evidence is offered to support their 130-week estimate for pipeline design, feasibility, permitting.

EPA – quite arbitrarily – elects to compress the schedule proposed by S&L. Specifically, EPA states:

> *"EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable. There are opportunities to compress schedules, expedite certain portions of the project schedule that are amenable to faster timetables, and conduct various components of the schedule concurrently.*
>
> EPA cites no basis for the compression – but describe that "*…sources expedite (where feasible) the scheduled deployment of CCS technology in a reasonable manner in order to meet the timing requirements of this action."* Regarding CO_2 capture design and development actions, EPA opine *"Each of these individual steps need not be in a sequential, and many of these actions can be planned well in advance, such that there can be significant time savings across these project planning steps."*[92]

Finally, EPA ignores risks inherent in emerging technologies, which given uncertainty in hardware design and performance – complicates parallel execution of engineering and procurement. EPA does not consider the risks in procuring components before all design work is complete – which can lead to cost overruns and schedule delay when it becomes necessary to modify the final design, perhaps altering early phases.

The achievable reduction in schedule in most cases is negligible – most schedules (i.e., Elk Hills) already include "parallel" steps such as final design and construction.

6.4 Real World CCUS Project Schedules

There are 13 CCUS projects for which schedules have been developed through at least the CO_2 capture. Few CCUS projects completely address the scope from process conception through CO_2 delivery and site injection (for sequestration or EOR). Two of these activities – Sask Power Boundary Dam 3 and Petra Nova – are discussed in Section 3. No other projects can offer real world experience with a complete project execution, accounting for all uncertainties in design, construction, and permitting.

This subsection reviews available schedule data from projects to compare to the EPA's proposed schedule. Schedules for both NGCC and coal-fired CCUS projects are considered. This high-level summary provides for each project site, as available, the following: the total project duration, the FEED design (including developing procurement specification) duration, and the period for construction. Comments on each project are offered for additional consideration.

[92] Steam EGU TSD at 36.

6.4.1 NGCC Schedule

Table 6-1 overviews schedule information for two NGCC applications- Elk Hills and Mississippi Power Plant Daniel Unit 4 - for which information is publicly available concerning schedule.

Table 6-1. Summary Schedule Information: NGCC CCUS Projects

Project/Site	Actions Addressed	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Elk Hills[93]	-CO_2 Site Prep: N/A -pre-FEED -FEED -Design/Const.	12 mos. (pre-FEED) 29 mos. FEED[94] Design/Spec 24 mos. (p.44)	55 mos.	96 mos. for FEED, other activities. Total ~8 yrs
Plant Daniel	-CO_2 Site prep: ECO_2S (start 2017) -FEED -Design/Const.	20 mos. (FEED: 1/29/20 to 9/30/21[95]	60 mos. including final design[96]	80 mos. w/o permitting for pipeline, sequestration

Elk Hills. This 550 MW (net) unit is regarded by the California Energy Commission as highly advantageous for CCUS, and describe it as "…one of the most suitable locations for the extraction of hydrocarbons and the sequestration of CO_2 in North America."[97] Even with these ideal conditions – the generating unit located directly above the sequestration fields that are already characterized - a minimum of eight years is required. After a presumed 12-month pre-FEED evaluation of CCS feasibility, the Elk Hills final report describes a 29-month FEED study, followed by 55 months for remaining activities. The activities per the project schedule (Appendix A, Figure A-1) following the 29-month FEED study are (a) 10 months of post-FEED events developing requests for proposals (RFPs), regulatory documentation and approval, and bids for select equipment, and (b) detailed engineering and procurement are (parallel activities).

Construction is authorized to start once 60% of detail engineering is complete and requires 24 months. Figure A-1 shows several major tasks are conducted in parallel.

Summary: The Elk Hills CCUS project benefits from near-ideal site conditions, with access to a well-characterized sequestration site. Despite the absence of delays due to pipeline permitting, this project experience demonstrates a project timeline between eight and nine years.

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93 2022 Elk Hills FEED Report. Page 1220.

94 Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Graphics Deck per DE-FE00311842, February, 2022. Page 6.

95 Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Plant, Virtual Meeting Graphics deck, Aug 2, 2021. P.21.

96 2022 Daniel FEED Report.

97 Appendix F, URS Report on CO_2 Sequestration for California Energy Commission, 2010.

Mississippi Power Plant Daniel Unit 4. This 525 MW (net) unit was evaluated in FEED study to retrofit the Linde-BASF amine-absorption process. A potential schedule describing activities from concept evaluation to CO_2 delivery – exclusive of permitting – can be considered, recognizing work began in 2017 to characterize the likely CO_2 sequestration site (Kemper County Storage Complex).[98] Consequently, considering the FEED study (20 months) and Final Design/Construction (60 mos) totals almost seven years; but this does not account for the work initiated in 2017 to evaluate sequestration options at the Kemper County Storage Complex. In addition, pipeline issues are not addressed – which as shown by experience in Iowa, could induce delays in the permitting, design, and construction of the 181-mile pipeline segment.

Summary. A realistic timeline for CCUS as represented for Daniel Unit 4 is best described by Southern Company in previous comments addressing CO_2 control options NGCC units.[99] This timeline – including technology evaluation, site permitting, process installation, and ramp-up for sustained operation – projects 10 years as necessary.

6.4.2 Coal-Fired CCUS Applications

Table 6-2 overviews schedule information for coal-fired applications, including Sask Power Boundary Dam 3 and Petra Nova. The implementation schedule for these projects is presented in Section 3.3.

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects

Project/Site	Actions Addressed in Schedule	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Sask Power	Per Sask Power: Commitment to completion[100]		3 yrs	6 yrs: Concept to completion. Existing EOR site, limited pipeline
Petra Nova[101]	6/10 to 12/16	Not specified	2014-2016[102]	80-mile pipeline to existing pipeline to EOR site.

[98] 2020 Kemper County Storage Complex.

[99] Comments of Southern Company to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Docket ID No. EPA-HQ-OAR-2022-0723, December 21, 2022.

[100] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.

[101] WA Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report: Final Public Design Report, Award No. DE-FE0003311. Pages 7, 8.

[102] https://www.businesswire.com/news/home/20170109006496/en/NRG-Energy-JX-Nippon-Complete-World%E2%80%99s-Largest.

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects (Cont'd)

Project/Site	Actions Addressed	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Basin Electric/Dry Fork[103]	Storage feasibility (March 2017)[104] to Oct 2029 CO_2 injection.	FEED. Oct 2019 to June 2022 (32 mos.)[105] Pilot study: 2022-2025	July 2025 – Oct 2029 for 1st CO_2 capture [106]	Detailed design start July 2025 to assure operation by Jan 2032[107]
Minnkota Power/Milton R Young[108]	-Storage feasibility (2015+), pilot plant -pre-FEED -FEED -Final Design/Con.	FEED: 2019 thru 2021 (24 mos.) Detailed Engineering and 6-12 mos. for vendor review, selection	Q1 2024-2028	Total duration: 2015-2028 Permitting duration atypical per state "primacy", adjacent sequestration site.
Prairie State[109]	-Illinois Corridor -FEED -Final Design/Con.	2/3/20 - 11/30/21 (22 months)[110]	EPC: 8/23 thru 4/27 (3.75 yrs)[111]	Sequestration study in Illinois Corridor started in 2007
San Juan[112]	-pre-FEED -FEED	5/22/2020-10/29/2021[113]	2/12/24 thru 6/04/26	21-mile pipeline not addressed
Shand	-pre-FEED -FEED/Final design	-pre-FEED complete -FEED 18 months[114]	Detailed Design/Constr 36 months[115]	

[103] 2022 MTR FEED Report.
[104] Wyoming CarbonSAFE Phase II: Storage Complex Feasibility (Commercial-Scale Carbon Storage Complex Feasibility Study at Dry Fork Station, Wyoming. DE-FE0031624, April 30, 2021.
[105] Commercial-Scale Front End Engineering Design (FEED) Study for MTR's Membrane CO2 Capture Process, Project Closeout Meeting, June 24, 2022. See graphic 3.
[106] Ibid.
[107] DE-FE0031846 page 38.
[108] Project Tundra: Postcombustion Carbon Capture on the Milton R Young Station, NRECA Update, October, 2022.
[109] 2022 Prairie State FEED Report. Page 145.
[110] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology, DOE/NETL Project Closeout Meeting, June 14, 2022. See Graphic 12. Hereafter 2022 Prairie State Close Out.
[111] Ibid. See graphic 41.
[112] Enchant Energy City of Farmington: San Juan Generating Station Carbon Capture – Final FEED Presentation, FE0031843. Graphic 42.
[113] Selch, J. et. al., *Large-Scale Commercial Capture Retrofit of the San Juan Generating Station*, FOA-0002058, Carbon Capture Front End Engineering Studies and CarbonSafe 2020 Webinar, August, 2020.
[114] The Shand SSC Feasibility Study: Public Report, International CCS Knowledge Center, November 2018, P. 115.
[115] Ibid.

Basin Electric/Dry Fork. This 440 MW (net) unit is the subject of a FEED study of the MTR Polaris membrane CO_2 separation technology. Activities at this site initiated in 2017, as part of the Wyoming CarbonSAFE studies, to determine the feasibility of nearby saline reservoirs (within 10 miles) for sequestration. A FEED study was completed in 32 months, ending June 2022. Per recommendation by S&L, MTR is constructing a 10 MW pilot plant to refine the process design. Pending these pilot plant results and project commitment decisions, detailed design is projected to start July 1, 2025, with construction completed to enable CO_2 delivery and injection by December 2029.

Summary: As site characterization for sequestration initiated in March 2017, a 12-year project duration is projected for this activity, *pending success with pilot plant results*.

Minnkota Power/Milton R. Young. Figure A-2 in Appendix A presents a timeline for activities from process feasibility to CO_2 injection, for retrofit of Fluor's Econamine FG Plus^{SM} process to flue gas generated from 477 MW(net) Unit 2 and 230 MW (net) Unit 1, with sequestration at the plant site. Activities initiated in 2015, consisting of evaluating terrestrial characteristics affecting CO_2 sequestration, and pilot plant tests in the host unit flue gas to determine the longevity of amine sorbents. Subsequent work was a pre-FEED study in 2017, followed by a full FEED initiating in 2018 and completed in mid-2022.

Pending an affirmative financial investment decision in early 2024, process engineering will initiate, consisting of vendor solicitation, review, and contract award. A 42-month period is reserved for construction, shakedown testing, and CO_2 injection by year-end of 2028.[116] Permits for CO_2 injection wells in North Dakota is enabled by the states authority to permit geologic carbon sequestration facilities as Class VI injection wells under the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) program.

Summary: This 12-year timeline reflects work directed for CCUS technology demonstration; there are limited opportunities to compress this schedule.

Prairie State Generating Station. Prairie State Generating Company was host site for a FEED study of CCUS on one of the 816 MW (gross) units, Unit 2. The analysis has produced a conceptual design and construction plan for the MHI KM-CDR process, as tested by the Petra Nova project. The Prairie State FEED study application was distinguished from previous application due to the type of coal being utilized and the size of the unit.

This project timeline is defined by both CO_2 capture studies, final design, and construction/commissioning, as well as evaluation of sequestration options in the Illinois Storage Corridor.[117] Also, as addressed in Section 5, CO_2 pipeline permitting issues are likely to be encountered, based on early observations of Illinois experience.

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[116] As described in comments to this rulemaking docket by Otter Tail Power, work to characterize the Milton R. Young site built upon work by the University of North Dakota Energy and Environmental Research Center.

[117] Greenburg, S., *Illinois Basin Decatur Project, Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III*, DOE DE-FC26-05NT42588, July 7, 2021.

The Illinois Basin-Decatur Project – conducted by the Midwest Geological Sequestration Consortium[118] – explored sequestration options that could be utilized by source in Illinois, including Prairie State. These activities, conducted independently of Prairie State, initiated in 2007 as an early element of the Illinois Storage Corridor project. The results identified potential sequestration options for up to the 6 million tonnes /year of CO_2 generated by Prairie State.[119] The original scope of the FEED study of the MHI KM-CDR CO_2 capture process required 23 months (February 2020 through December 2021). The FEED study was then extended by six months, to June 30, 2022. The final phase of detailed engineering, procurement, and construction, described in Figure A-3 of Appendix A, was originally estimated to require 3.75 years. This work has not commenced.

Summary: The timeline for sequestration options and acquiring CO_2 pipeline permits within the Illinois Storage Corridor will require further evaluation and analysis. As reported in their comments submitted as part of this rulemaking, a timeline representing Prairie State project conception to CO_2 injection for sequestration is anticipated to require as much as eight to ten years.

<u>San Juan Generating Station.</u> Enchant Energy proposed to acquire the San Juan Generation Station in 2022, and deploy CCUS to Units 1 and 4, totaling 877 MW(net) capacity. A preliminary FEED study was completed evaluating retrofit of the MHI process to these western bituminous coal-fired units. This study was conducted from 5/22/2020 through 10/29/2021. Subsequently, a FEED study addressing engineering, procurement, and a preliminary evaluation of construction requirements was initiated in October 2022. The resulting schedule describes construction initiating in early 2024 and being completed in mid-2026, followed by commissioning and testing, enabling commercial duty in September 2027.

This work included an early permit for CO_2 pipeline to access to Cortez EOR pipeline; permitting activity was not completed.

Summary: This project – absent final permitting for a 21-mile pipeline – as planned would require 7.25 years without pipeline construction supporting access to EOR, or CO_2 sequestration site injection.

<u>Shand.</u> A general discussion of Shand states a project investment decision for 2029 CCS duty should be made in 2024/2025; presumably this investment decision is predicated upon a satisfactory FEED-type study to "de-risk" the decision. This FEED study is projected by Sask Power to require 18 months; accelerating the "start" of activities to 2022/2023. No discussion of CO_2 disposition actions is addressed; a pipeline of approximately 20 miles is required for Shand to deliver CO_2 to the Boundary Dam site for forwarding to the Weyburn fields for EOR.

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[118] Illinois Basin Decatur Project: An Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III, DE-FC26-05NT42588, July 7, 2021.
[119] Whitaker, S., Illinois Storage Corridor: Phase 3 CarbonSafe, Update Meeting, November 9, 2021.

Summary. The projected schedule for FEED study through CO_2 delivery per Shand owners appears to be 6-7 years. The final timeline would be determined by any additional work to assure the Weyburn oilfield can effectively utilize the additional CO_2 for EOR, or to open new EOR activities in other nearby regional oil fields and construction and permitting of the pipelines.

7 EPA-PROJECTED CCUS INSTALLATIONS

EPA in the 2023 Integrated Baseline Analysis projects that 39 coal-fired units will adopt CCUS by 2030.[120] The basis for the projection is limited to the IPM model selection of units – based on approximate operating characteristics assigned to each unit – to match the required generation. Table 7-1 identifies these units, which are exemplary only and assigned no significance.

Table 7-1. Units Projected by EPA IPM to Adopt CCUS by 2030

State	Unit ID	Plant Name	Capacity (MW)
Alabama	4	James H Miller Jr	477
Arizona	3,4	Springerville	2 x 281
Colorado	3	Comanche (CO)	501
Colorado	1	Pawnee	0
Florida	BB04	Big Bend	292
Illinois	41	Dallman	135
Illinois	1, 2	Prairie State	2 x 851
Indiana	1, 2	Gibson	2 x 427
Kentucky	2	East Bend	399
Kentucky	1, 2	H L Spurlock	207, 353
Kentucky	4	Mill Creek (KY)	324
Michigan	3, 4	Monroe (MI)	2 x 528
Montana	PC1	Hardin Project	65
North Dakota	1, 2	Antelope Valley	2 x 289
Ohio	2	Cardinal	2 x 407
Texas	BLR2	J K Spruce	538
Texas	1, 2	Oak Grove (TX)	2 x 573
Utah	1, 2, 3	Hunter	320, 292, 314
West Virginia	3	John E Amos	515
West Virginia	1, 2	Mitchell (WV)	2 x 538
Wyoming	1	Dry Fork Station	253
Wyoming	BW73, 74	Jim Bridger	2 x 354
Wyoming	1, 2, 3	Laramie River	3 x 385
Wyoming	3, 1	Wygen 1, 2	53, 56
Wyoming	1	Wygen III	63

120 EPA 2023 Integrated Baseline Analysis

A detailed critique of EPA's analysis is submitted to this rulemaking docket as part of comments by the Power Generators Air Coalition and the American Public Power Association.[121]

Figures 7-1 and 7-2 depict the location of each of these generating units – "hypothetically" assigned CCUS by the EPA IPM model - on a continental map. Also shown are boundaries for four categories of geologic sequestration (active EOR, deep saline formations, oil and gas reservoirs, and unmineable coal seams), and existing CO_2 pipelines. Each plant is encircled showing a radius of proximity to the sequestration sites or existing pipelines for EOR. Figure 7-1 shows the radius of 100 km and Figure 7-2 shows the radius of 200 km. The cited range of 100 km and 200 km are examples only, and do not represent a recommended or "default" distance for sequestration or EOR access.

[121] Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule, prepared by James Marchetti, August 7, 2023.

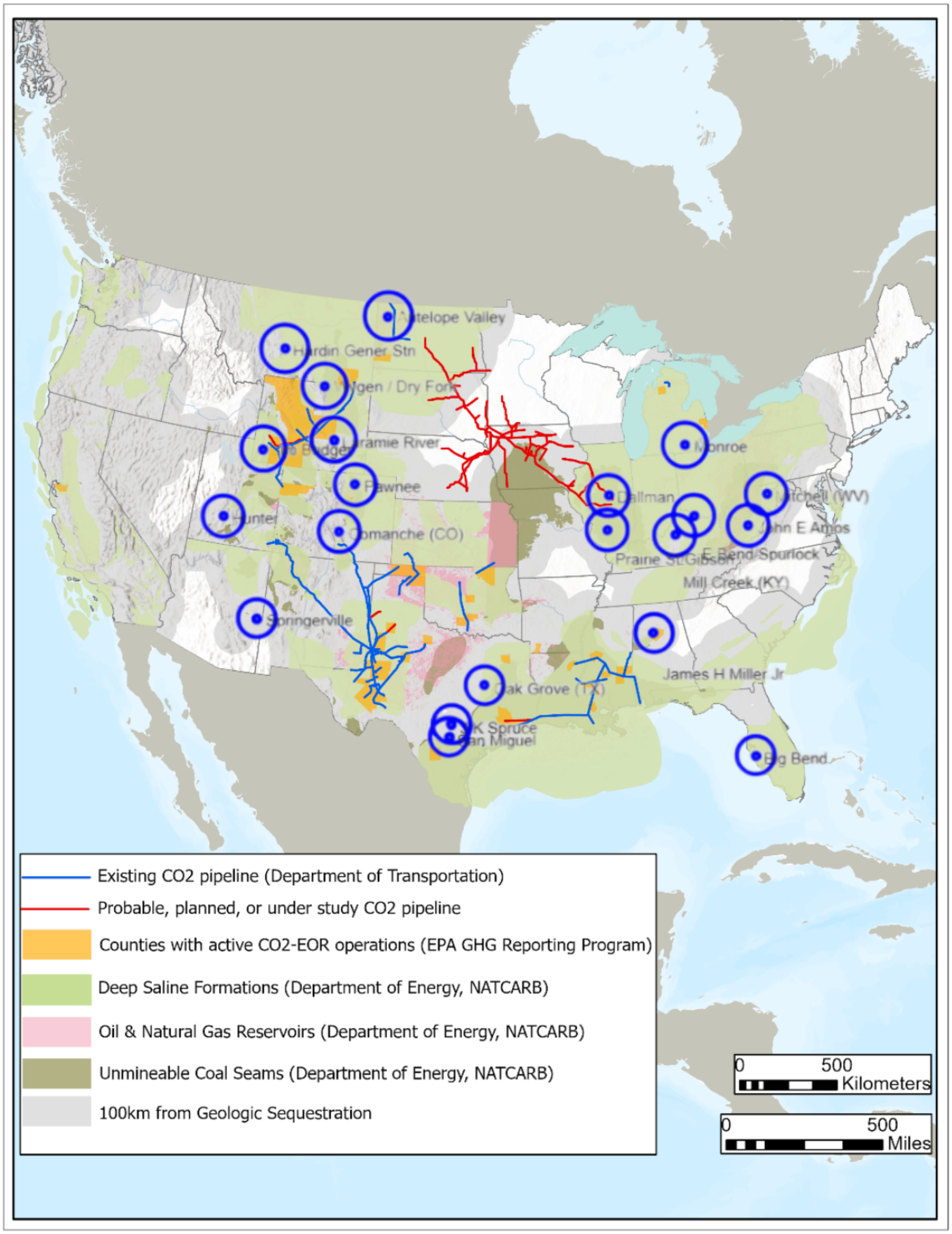

Figure 7-1. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 100 km Proximity

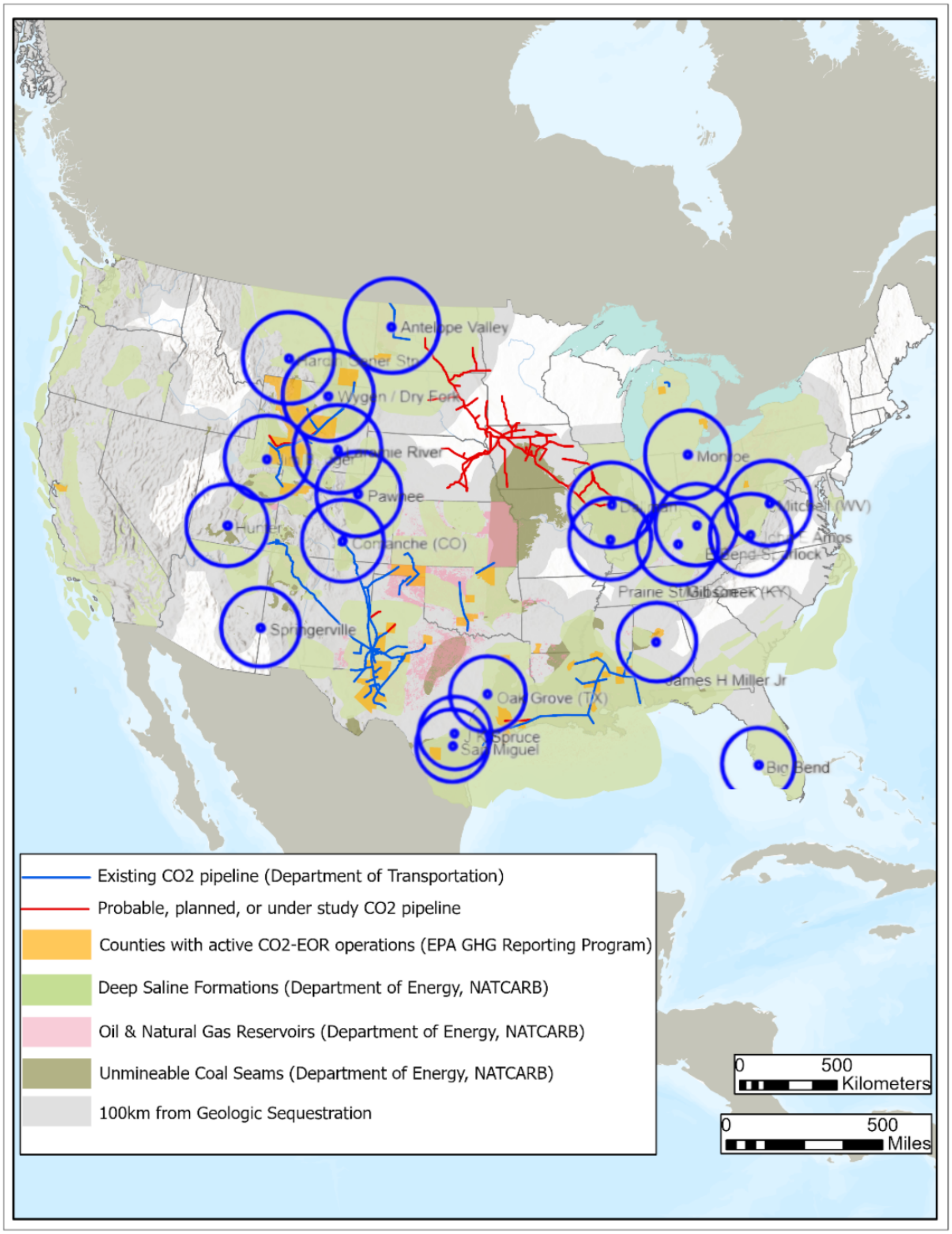

Figure 7-2. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 200 km Proximity

Appendix A. Flawed Cost Extrapolations for NGCC Application

EPA projects capital, fixed operating, and variable operating costs for small combustion turbines by extrapolating results from three NETL reports. These reports define CCUS cost for coal,[122] combustion turbines,[123] and describe a methodology for scaling costs.[124] Each step in the extrapolation removed from a specific design and cost estimate compounds the uncertainties of each singular estimate. Consequently, confidence in these costs is low. The shortcomings to this approach are attributable to EPA's misuse of the power-law relationship and selection of scaling exponents, described below.

The general approach employed by NETL and accepted by EPA – use of a power scaling law to project cost to conditions other than the reference case – is valid when used within the range recommended, and the scaling "exponents" are appropriate. The NETL guidelines are not observed, as EPA employs the power-law relationship to extrapolate costs over a range of CO_2 mass and gas processing rates that vary by up to a factor of 6.

NETL issued Scaling Quality Guidelines[125] in 2013, which describes the conventional power law equation follows:

$$SC = RC * \left(\frac{SP}{RP}\right)^{Exp} \qquad \text{(Equation A-1)}$$

Where:
Exp: Exponent
RC: Reference Cost
RP: Reference Parameter
SC: Scaled Cost
SP: Scaling Parameter

Notably, NETL warn in the 2013 *Scaling Quality Guidelines* that generalizing results to process conditions significantly different from the reference design case can significantly alter the result. EPA's range of partial treatment and different CO_2 gas content between coal and NGCC CCUS represent a significant departure from reference case conditions.

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122 2020 Baseline CCUS Costs.
123 *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* DOE/NETL - 2023/4320, October 14, 2022.
124 *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO2 Capture Rate in Coal-Fired Power Plants,* DOE/NETL-2019, December 23, 2020.
125 2013 Scaling Quality Guidelines.

NETL in their 2013 *Scaling Quality Guidelines* advise caution in the use of power law relationship to scale costs. Specifically, NETL cite:

There are limitations on the ranges that can accurately be addressed by the scaling approach. There can be step changes in pricing at certain equipment sizes that may not be captured by the scaling exponents. Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items. For example, it is known that the combustion turbine is an incremental cost and is specific to one level of performance.[126]

NETL advise exponents for use in scaling CO_2 flue gas treatment technology. The specific methodology EPA elected in this rulemaking differ from the NETL approach, thus scaling exponents differ. However, what does not differ is a limit in the range of flue gas processed beyond which errors are introduced. NETL advise in Exhibit 2-17 the range of the lb/hr of CO_2 removed for which the power-law methodology to scale a "CO_2 Removal System" is valid – specifically citing 445,000-689,000 lb/hr. Notably, this is less than a factor of two variance. EPA's extrapolations violate this recommended range.

[126] Ibid. page 14

Appendix B. Example CCUS Project Schedules

Figure B-1. Elk Hills Project Schedule: Post-FEED Study Activities [127]

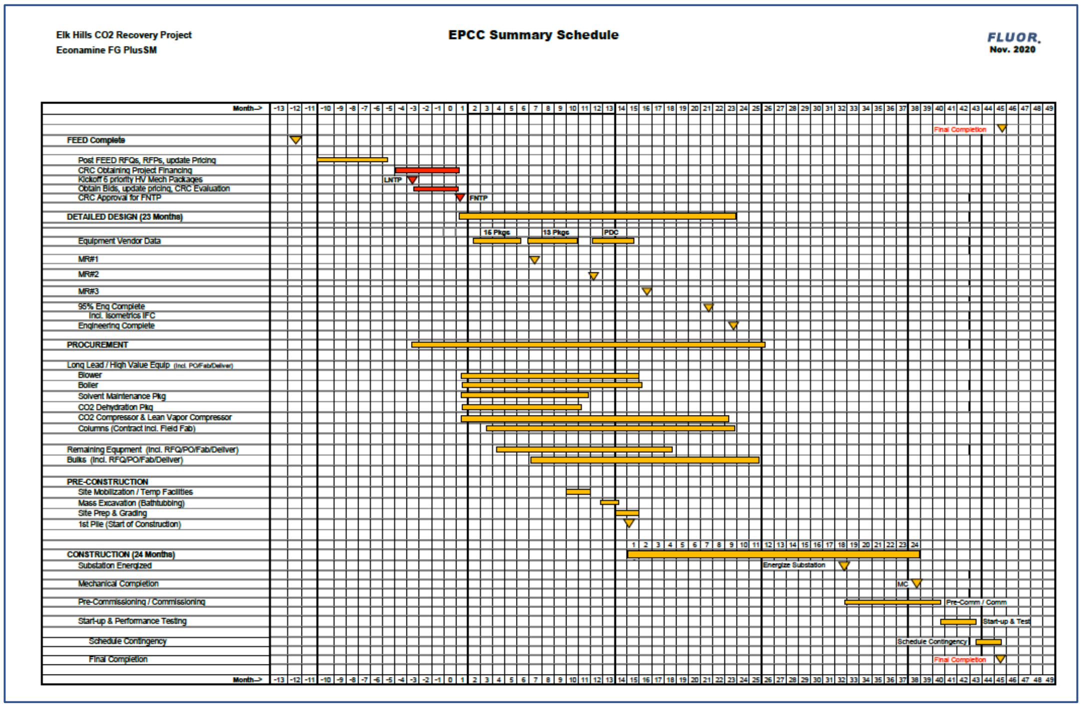
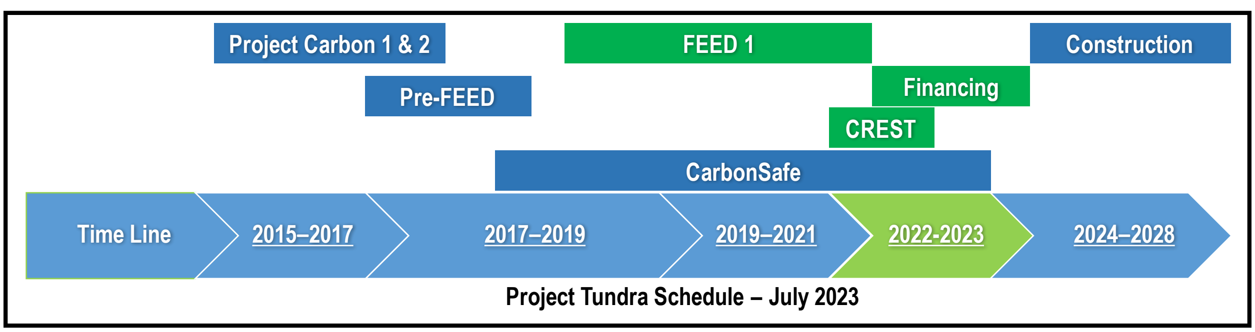


Figure B-2. Minnkota Power Milton R Young Station: Complete Schedule [128]



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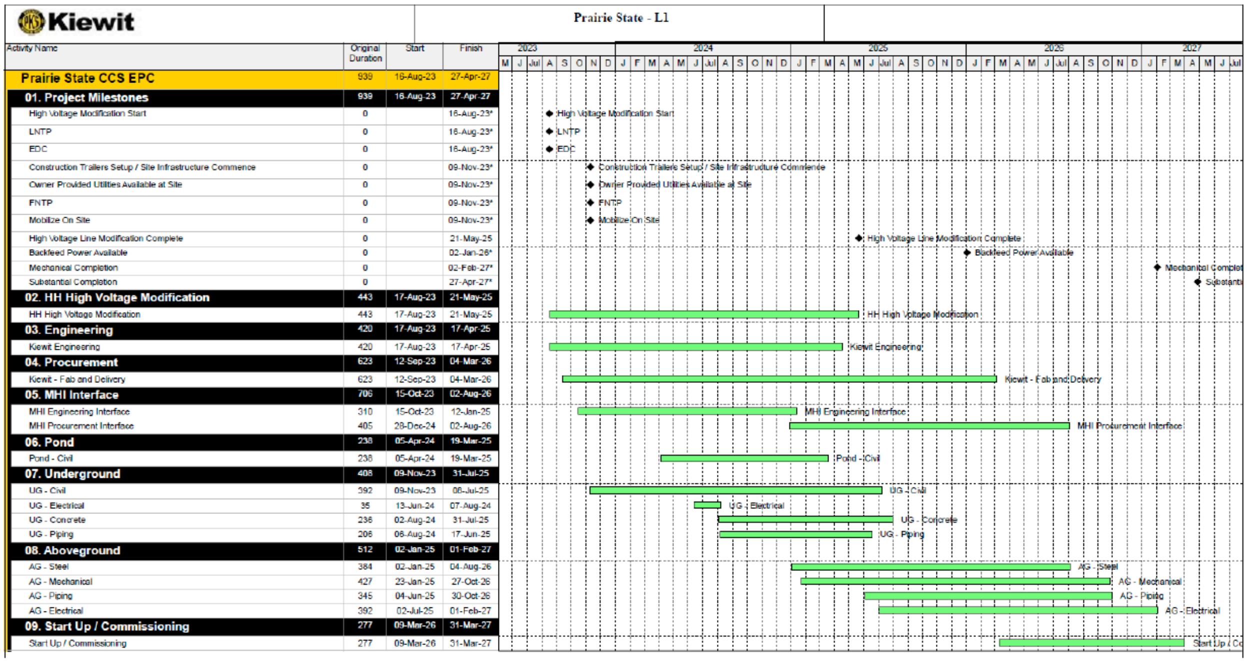
[127] 2022 Elk Hills FEED Report.
[128] Mikula, S, Personal Communication, July 25, 2023.

Figure B-3. Prairie State Final Engineering, Procurement, Construction Schedule [129]



Activity Name	Original Duration	Start	Finish
Prairie State CCS EPC	939	16-Aug-23	27-Apr-27
01. Project Milestones	939	16-Aug-23	27-Apr-27
High Voltage Modification Start	0		16-Aug-23*
LNTP	0		16-Aug-23*
EDC	0		16-Aug-23*
Construction Trailers Setup / Site Infrastructure Commence	0		09-Nov-23*
Owner Provided Utilities Available at Site	0		09-Nov-23*
FNTP	0		09-Nov-23*
Mobilize On Site	0		09-Nov-23*
High Voltage Line Modification Complete	0		21-May-25
Backfeed Power Available	0		02-Jan-26*
Mechanical Completion	0		02-Feb-27*
Substantial Completion	0		27-Apr-27*
02. HH High Voltage Modification	443	17-Aug-23	21-May-25
HH High Voltage Modification	443	17-Aug-23	21-May-25
03. Engineering	420	17-Aug-23	17-Apr-25
Kiewit Engineering	420	17-Aug-23	17-Apr-25
04. Procurement	623	12-Sep-23	04-Mar-26
Kiewit - Fab and Delivery	623	12-Sep-23	04-Mar-26
05. MHI Interface	706	15-Oct-23	02-Aug-26
MHI Engineering Interface	310	15-Oct-23	12-Jan-25
MHI Procurement Interface	405	28-Dec-24	02-Aug-26
06. Pond	238	05-Apr-24	19-Mar-25
Pond - Civil	238	05-Apr-24	19-Mar-25
07. Underground	408	09-Nov-23	31-Jul-25
UG - Civil	392	09-Nov-23	08-Jul-25
UG - Electrical	35	13-Jun-24	07-Aug-24
UG - Concrete	236	02-Aug-24	31-Jul-25
UG - Piping	206	06-Aug-24	17-Jun-25
08. Aboveground	512	02-Jan-25	01-Feb-27
AG - Steel	384	02-Jan-25	04-Aug-26
AG - Mechanical	427	23-Jan-25	27-Oct-26
AG - Piping	345	04-Jun-25	30-Oct-26
AG - Electrical	392	02-Jul-25	01-Feb-27
09. Start Up / Commissioning	277	09-Mar-26	31-Mar-27
Start Up / Commissioning	277	09-Mar-26	31-Mar-27

[129] 2022 Prairie State Close Out. At 41.

Attachment D

EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

Final Report

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EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) is proposing new emission guidelines for CO_2 at existing fossil fuel-fired electric generating units. The guidelines propose that the best system for emission reduction for coal-fired electric generating units is carbon capture and storage (CCS). Carbon capture rates must meet a minimum of 90%. EPA believes that CCS is a mature technology that can be implemented to meet a 2030 deadline.

Examples are given in the guidelines to show the maturity of CCS; however, these examples spotlight facilities that are small in size, and all but two examples, Saskpower's Boundary Dam Unit 3 and the Petra Nova project, perform no subsurface injection at all. The examples are of slipstream systems and production facilities. No example is given of a facility larger than Petra Nova's 240-MW facility capturing CO_2 and injecting it into the subsurface because one does not exist.

With respect to the transport and storage of CO_2, sufficient demonstration of CCS with all the appropriate regulatory frameworks in place has not occurred. Documentation is not present to support EPA's geographic analysis, and the information the Agency does possess is out of date.

The timeline for implementation of CCS is expected to take much longer than anticipated by EPA. One example is EPA review of UIC (underground injection control) Class VI permits. In the last year, the number of permits under review has risen from 9 to 98, and historically, it appears the process can take more than 6 years per permit. Overall, from evaluation to commercial operation, an optimistic timeline indicates it can take at least 7 years to complete. Any disruptions to permitting, design, or construction can extend this for many additional years, which will be incompatible with meeting compliance in 2030.

Costs related to CCS can vary widely depending on conditions at the location and the permitting required. Based on experience, the costs to design and construct the carbon capture facility can exceed $1 billion. The pipeline for transportation of the CO_2 to the injection site can cost $600,000–$2,500,000 per mile or more, with development of the injection site costing $30 million or more, depending upon the number of injection and monitoring wells required. As a result of these substantial costs, final investment decisions on the construction and commissioning of carbon capture and transportation systems are often contingent upon an associated geologic storage facility permit being available and approved. This further extends the time to implement new carbon capture and storage well beyond the proposed compliance date.

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. Based on the supported conclusions and the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

INTRODUCTION

The proposed change to the U.S. Environmental Protection Agency's (EPA's) rules within 40 CFR Part 60 details proposed carbon emission standards for both fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. In this document, EPA outlines climate change and its impacts; recent developments in emissions; proposed requirements for both new and reconstructed stationary combustion turbine electric generation units (EGUs); requirements for new, modified, and reconstructed fossil fuel-fired steam generating units; the proposed regulatory approach for existing fossil fuel-fired steam generating units; the proposed regulatory approach for emission guidelines for existing fossil fuel-fired stationary combustion turbines; and impacts of the proposed actions. Within the document, EPA discusses the best system of emission reduction (BSER) for various subcategories of fossil fuel-fired steam generating units and subcategories of fossil fuel-fired stationary combustion turbines. The primary focus of this review is to examine the application of carbon capture and storage (CCS) technologies to these EGUs through their present state of readiness and adequacy of demonstration. CCS includes the carbon capture process itself, transportation of the CO_2, and storage or sequestration.

SUBCATEGORIZATION OF ELECTRIC GENERATION UNITS

The EPA categorizes EGU's into two primary groups: fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. Various subcategories exist under the umbrella of these two categories, which are further discussed below.

Of the eleven subcategories for fossil fuel-fired steam generating units, EPA is proposing the application of CCS to one: long-term existing coal-fired steam generating units. These units are coal-fired steam generating units that have not elected to commit to permanently cease operations by January 1 of 2040. This CCS system is required to have a CO_2 capture rate of 90%, with the associated degree of emission limitation a CO_2 reduction of 88.4% lb CO_2/MWh-gross (proposed rule pages 33359 and 33360).

EPA is proposing to regulate existing fossil fuel-fired stationary combustion turbines in two segments, with only the first outlined in this proposed EPA regulation, the second to be released in a separate regulation document later. In this first segment, EPA proposes regulation for baseload turbines over 300 MW. EPA defines baseload as having a capacity factor greater than 50% (proposed rule page 33362).

EPA believes that two technologies are possible BSERs for fossil fuel-fired stationary combustion turbines over 300 MW operating at a capacity factor of greater than 50% coupled with heat-rate improvements: i) cofiring with low greenhouse gas (GHG) hydrogen and ii) CCS. EPA believes that the 300-MW threshold for applicability is appropriate because it focuses on the units with the highest emissions where CCS is likely to be the most cost-effective.

ADEQUACY AND APPLICABILITY OF CARBON CAPTURE

Several technologies are included under the umbrella of carbon capture: postcombustion, precombustion, oxyfuel combustion, and direct air capture. Direct air capture does not capture CO_2 directly from a GHG point source prior to its emission but after. Therefore, direct air capture is not further discussed, as it is not applicable to being integrated into fossil fuel-fired steam generating EGUs or fossil fuel-fired turbines.

Oxyfuel combustion involves combining a fuel, such as coal or natural gas, with pure oxygen. Since the oxidant stream is pure oxygen instead of air, such as in a conventional combustor, the combustion reaction does not create other combustion by-products such as NO_x. CO_2 and H_2O steam are produced from the reaction, which is then used to power a turbine. Since this combustion reaction creates a stream of pure CO_2, the CO_2 can be captured without the need for additional systems that are required in pre- or postcombustion CO_2 capture. However, these systems do require a constant and sizable supply of pure oxygen, often necessitating an air separator to be included in the process (1). Additional challenges of oxyfuel combustion systems are the high capital costs, energy consumption, and operational challenges of oxygen separation (2). Research of oxyfuel combustion is still ongoing, with projects focusing on lab-, bench-, and pilot-scale testing to understand the combustion mechanics of oxyfuel combustion at high temperatures and pressures, verify system design and operation concepts, and improve the performance of ancillary system components (3). Some demonstrations of oxyfuel combustion systems have been conducted, the largest being a retrofitted 100-MWth PC boiler in Central Queensland, Australia, which operated from December 2012 to March 2015. In that time, the unit achieved 10,000 hours of oxyfuel combustion and 5500 hours of carbon capture (4).

Precombustion CO_2 capture constitutes the removal of CO_2 from a fuel source prior to its combustion. This is commonly achieved through fuel gasification, in which the feedstock, such as coal, is partially oxidized with steam and oxygen-rich air under high temperature and pressure to form syngas, which is a mixture of hydrogen, carbon monoxide, CO_2, and smaller elements of other gases, such as methane. The syngas can then undergo the water-gas shift reaction, which converts the carbon monoxide and water in the gas to hydrogen and CO_2. The CO_2 can then be captured, and the H_2-rich fuel combusted. Since the precombustion fuel stream is rich in CO_2 and at a higher pressure, extraction of the CO_2 from the stream is easier than in postcombustion systems. However, the cost of a gasification system is often greater than a traditional coal-fired power plant (5). Therefore, precombustion CO_2 capture is not considered a leading technology for CO_2 emissions reduction in the electrical generation industry. But it has been shown to be effective in the chemical processing industry, with Great Plains Synfuels Plant in Beulah, North Dakota, having been in operation for the past 25 years and remaining the only coal-to-synthetic natural gas facility in the United States. Great Plains Synfuels Plant produces synthetic natural gas from lignite coal and captures its CO_2 for utilization in enhanced oil recovery (EOR) in Canada. The plant is capable of capturing up to 3 million tons of CO_2 per year. Since 2000, CO_2 emissions at the Synfuels Plant have been reduced by 45% (6).

Postcombustion CO_2 capture involves the removal of CO_2 from the flue gas of an EGU. After the fuel has been combusted, the exhaust gases are processed to filter out potential contaminants such as ash and SO_2, then the exhaust gases go to the postcombustion CO_2 capture system, which captures the CO_2 from the gas stream through a reaction with a chemical solvent (amine). This solvent captures the CO_2 gas, and the solvent and gas are later separated in the stripper column, where heat and pressure are used to regenerate the solvent and create a stream of pure CO_2, that can then be compressed, transported, and sequestered. The use of chemical solvents for carbon scrubbing is the most commonly acknowledged process for capturing CO_2 from gas mixtures (7) and has been used in the natural gas industry to separate CO_2 from other gases since the 1930s (8). Current federally funded work in solvent-based postcombustion capture is seeking to address key challenges to deployment, which include scale-up, parasitic load, process integration, water use, and capital costs (8). Additionally, solvent degradation can be a significant issue.

The large-scale carbon capture facilities that are in operation throughout the world are mostly focused on natural gas processing (9). Only two facilities are operating at coal-fired power plants: Saskpower's Boundary Dam Unit 3 (110 MW) and the Petra Nova Project (240 MW equivalent), which will be discussed later. Postcombustion CO_2 capture has yet to be demonstrated at a baseload facility larger than Boundary Dam Unit 3. Parasitic load requirements for the operation of the carbon capture system decrease the net power output of the EGU by roughly 20% (10).

With respect to carbon capture technology, the proposed rule states that:

> *"The EPA is proposing that the CO_2 capture component of CCS has been adequately demonstrated and is technically feasible based on the demonstration of the technology at existing coal-fired steam generating units…" [page 33291]*

The design and integration of CO_2 capture facilities can vary based on the configuration of the EGU and fuel source. Variations, such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, and ramping due to load changes, all affect the applicability and cost of implementing CCS at fossil fuel-fired EGUs (11). For example, in Wyoming, most of the existing power generation fleet is not equipped with environmental control systems that remove enough NO_x, SO_x, and other air pollutants to prevent the accelerated degradation of the amine solvent inside of the CO_2 capture system. 87% of EGUs have flue gas desulfurization systems, and 56% of EGUs have postcombustion NO_x control systems, whereas nearly all Wyoming EGUs only have particulate and mercury control devices installed. Before a CCS system could be constructed and retrofitted, these facilities would need to be upgraded to meet these requirements (12). These upgrade requirements are not considered by EPA in the proposed capture requirements.

Typical solvents utilized in carbon capture systems are amine-based. The name amine refers to a chemical function group that includes compounds with a nitrogen atom and a lone pair. A common amine in CCS systems is monoethanolamine (MEA), colloquially referred to in industry as amine. Amines are susceptible to degradation, and solvent management can be a significant challenge. Amine degradation can reduce solvent efficiency or cause an unintentional release into the atmosphere. This degradation can happen because of several factors: thermal or oxidative degradation or reaction with impurities in the flue gas stream. Advanced amines are being developed, which reduce thermal or oxidative degradation of the amine and improve its capture efficiency; however, impurities still have a significant impact on the life of amine.

Thermal Degradation

The heat involved in the regeneration process, where CO_2 is stripped from the amines, can cause these molecules to break down, leading to loss of capture efficiency and the need for frequent solvent replacement. This aspect is poorly addressed in literature due to the sensitive nature of sharing specific information from vendors. This quickly increases operating costs and results in large quantities of liquid waste. The EPA does not recognize or address this issue.

Oxidative Degradation

The solubility of oxygen in amine solutions is a key issue in dealing with problems like degradation and corrosion (13). An increased level of oxygen in the amine solvent changes the solvent chemistry, increasing its tendency to cause oxidation and corrosion. The Technology Centre Mongstad (TCM) studied amine degradation in a combined heat and power plant (CHP) and noted significant corrosion. Significant material thickness reduction and leakage on the CHP reboiler heat exchanger plates were observed. The CHP stripper packing surface was coated by a layer of corrosion products. This layer was "leaching" out in the solvent upon restart of the CHP stripper, resulting in rapidly increasing iron content in the fresh solvent (14). The application of an oxygen scavenger, a chemical additive to the amine solvent, could be used as a preventive measure to keep solvent degradation low. This form of degradation of the amine solvent is correlated to the composition of the EGU's flue gas and not the capture rate of the CCS system; therefore, the effects of the flue gas on the solvent chemistry must be individually investigated at each facility.

Degradation by Reaction with Impurities

When TCM tested amines on a residue fluidized catalytic cracker (RFCC), they had not been able to operate the amine plant with RFCC flue gas because of very high amine emissions (>20 ppm) caused by sulfuric acid aerosol and dust particles present in the flue gas (15). With installation of a Brownian diffusion (BD) filter upstream from the absorber, more than 95% of the aerosols were removed, and together with optimization of plant process parameters and configuration, the amine emissions were reduced. It is known that both SO_2 and NO_x will give unwanted reactions with MEA (16).

Although the degradation mechanisms for MEA have been extensively studied in the literature (16–19), testing, understanding, and mitigating amine degradation on a plant-by-plant basis are crucial for the sustainable and efficient application of CCS technology. Research is ongoing to develop advanced amines and to improve the process design to minimize amine losses, such as optimizing operating conditions, implementing solvent purification processes, and better managing impurity variability in the flue gas.

The above discussion illustrates that additional investigation is required at the specific facility being considered for installation of a carbon capture system that may include significant construction and redesign to accommodate CCS implementation.

CARBON CAPTURE EXAMPLES

EPA cites several examples of successful plant operation within its proposed guidelines, and a few of them will be briefly discussed. These examples do show that CCS is possible and promising and present a promising solution for the future; however, they do not reflect the needs as set forth by EPA as they are examples of slipstream systems, are smaller capacity units, do not employ the full CCS process, and are capturing CO_2 at levels below 90%.

AES Corporation's Warrior Run Generating Station

The Warrior Run Station is a 180-MW bituminous coal-fired power plant located in Maryland. The installed CO_2 capture system captures a small slipstream of the facility's flue gas to produce 330 t CO_2/day of food-grade CO_2 for use in food processing. The process used is an ABB Lummus unit with MEA as its solvent (20). The installed CO_2 capture system captures anywhere between 4% to 6% of the CO_2 emissions of the plant (21). The important highlights are that the system is a slipstream of a small power plant which produces a product and does not inject CO_2 into the subsurface. Therefore, the small capacity, slipstream system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines.

AES Corporation's Shady Point Generating Station

Shady Point Power Plant is a 320-MW circulating fluidized-bed subbituminous coal-fired power plant located in Oklahoma. A slipstream of the power plant's flue gas is captured to produce 200 t CO_2/day of food-grade CO_2 for use in food processing. With the plant emitting 1.24 million t CO_2/year, the yearly capture rate approximates to 6%. This process uses an ABB Lummus scrubber system with MEA as its solvent (20). Like the Warrior Run Generating Station, this is a small slipstream which produces a product and does not inject CO_2 into the subsurface. This example has little correlation to the levels EPA would mandate under their proposed guidelines.

Searles Valley Minerals Soda Ash Plant

The Searles Valley Minerals Soda Ash Plant, located in California, captures approximately 800 t CO_2/day from the flue gas of the 62.5-MW Argus Cogeneration Plant, a subbituminous coal-fired power plant that generates electricity and steam. The CO_2 is captured with an ABB Lummus MEA capture unit, and the captured CO_2 is used for the carbonation of brine in the production of soda ash (20). With the plant emitting 1.63 million t CO_2/year, the capture rate approximates to 18%. Like the previously discussed facilities, the small capacity system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines. The correlation between this facility and what is expected under the proposed guidelines is minimal.

Quest CO_2 Capture Facility

The Quest Carbon Capture and Storage Project is a CCS facility in Alberta, Canada, that began operation in 2015. Quest removes CO_2 from the process gas streams of three hydrogen manufacturing units (HMUs), equating to 1 million t CO_2/year, within the Scotford upgrader facility, which emits 3 million t CO_2/year. Between the years of 2015 and 2021, Quest has been able to capture between 77.4% and 83% of CO_2 emissions from the HMUs, with the average CO_2 capture rate of 79.4% (22). Although the facility has demonstrated the ability to store CO_2, the overall capture rate of the facility falls short of EPA's proposed 90% minimum capture rate.

Saskpower's Boundary Dam Unit 3

Saskpower's Boundary Dam Unit 3 (BD3) is a 110-MW lignite-fired unit in Saskatchewan, Canada. Development of the CCS facility began in 2007, with the decision to move forward with construction in 2010, and provides CO_2 for both EOR and sequestration. Saskpower selected the CANSOLV process, an amine solvent system, for its CO_2 capture process. During its first year of operation, BD3 achieved a CO_2 capture rate of 50% of its designed volume. This capture rate has been improved through design and operations optimizations, although the capture rate is still below its designed CO_2 production levels. Significant issues included operational difficulties from construction and design deficiencies, issues with fly ash carryover, a lack of redundancy and isolation capabilities, and amine degradation and foaming (23). Lessons learned from this CCS facility are slow to be released, and there may be other operational challenges that industry and EPA do not know about. This facility exemplifies the site-specific challenges that are to be expected with CCS implementation and is only one-third the scale of plants that would be addressed in EPA's proposed emission guidelines.

NRG Energy's Petra Nova Facility

The Petra Nova facility, located in Texas, is a 240-MW equivalent slipstream of flue gas from the W.A. Parish coal-fired facility. This postcombustion capture facility started operation in 2017 and fulfilled its objectives of demonstrating carbon capture at this scale coupled with compression and transportation of CO_2 to an oil field for EOR only. The facility was shut down because of low oil prices in May 2020 due to no alternate method of sequestration. Market-driven EOR alone does not adequately demonstrate CCS that will meet EPA's proposed continuous emission reduction. During its 3-year operation, it suffered frequent outages and missed its carbon capture targets by ~17% (24).

AVAILABILITY FACTOR

The availability factor is a measure of the amount of time a system is in operation and not undergoing maintenance, repair, and unexpected down time and is given as a percentage. The most relevant example given by EPA for an EGU utilizing a fully integrated carbon capture system is Boundary Dam Unit 3, as mentioned above. Since its start-up in 2014, the unit has experienced operational issues that have led to more frequent capture facility outages than originally anticipated. The primary issues experienced have been with fly ash and fly ash component buildup in the CCS facility. Heat-transfer surfaces, such as the reboilers, fouled over time. The packing in the absorbers and the strippers also experienced fly ash buildup and the development of organic deposits. These issues affected the capture capacity of the facility as the heat-transfer efficiency decreased and the gas flow rate became limited because of deposits. The implementation of advanced demister wash systems has extended the facility's operational time between maintenance outages, and wash systems for the booster fan and redundant heat exchangers, with isolations, have enabled the facility to conduct online maintenance. The capture facility has also experienced compressor failures that increased its unplanned outage time for the years of 2021 and 2022. Figure 1 shows the yearly percent availability of the Boundary Dam Unit 3 capture facility's availability, planned maintenance outages, and unplanned outages for the years of 2014 through 2022 relative to the operation of the power plant (25).

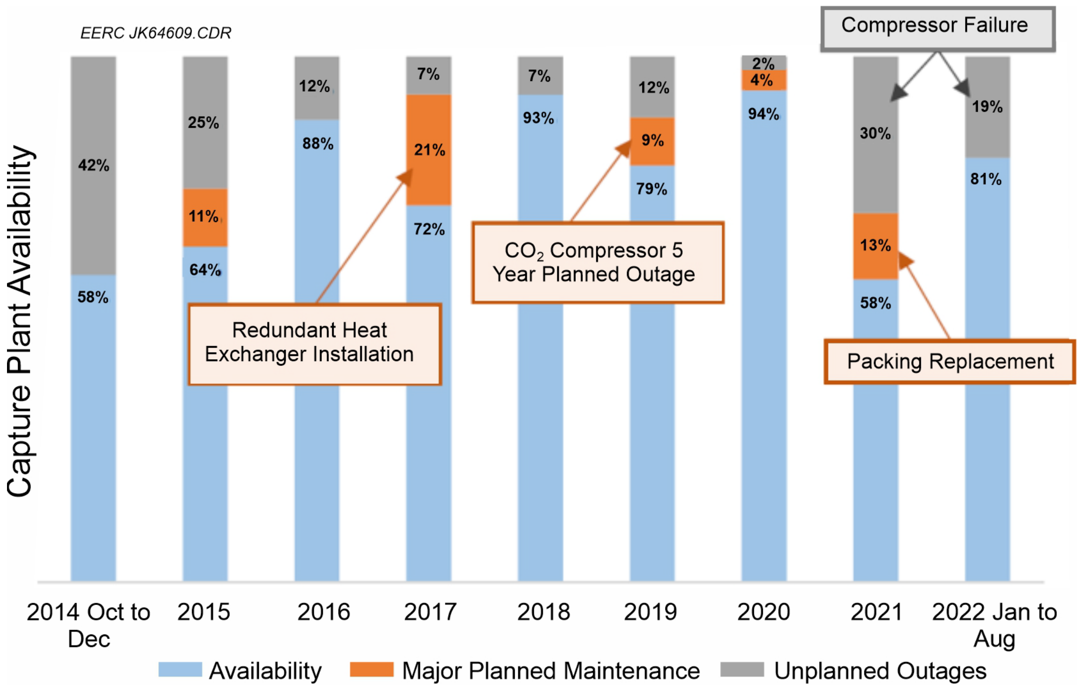

Figure 1. Availability of Boundary Dam Unit 3 capture facility and CO_2 compressor relative to the Unit 3 power plant (25).

The figure shows that annually the capture facility was not able to operate the full time the power plant was in operation and for only 2 years was the facility operating above 90% of the available time. Based on this information, even with the capability to capture greater than 90% of the CO_2 emissions, it is premature to expect that a capture facility will be able to operate with an availability factor sufficient to comply with the annual emission requirements of the proposed rule.

NATURAL GAS CARBON CAPTURE

Many of the demonstrations studied by EPA are coal-fired power plants with small slip stream CO_2 capture systems. EPA proposes CCS as the BSER for stationary combustion turbines for greater than 300 MW and over 50% capacity factor; however, CCS has been studied less at natural gas EGUs than coal-fired EGUs. Among coal-fired EGUs, each facility has different CCS retrofitting and integration needs, due to the operational parameters, facility differences, and the composition of flue gas. One of the primary challenges with natural gas is its lower carbon load. Natural gas-fired generation produces less CO_2 per MWh than coal-fired facilities, meaning that the capture plant design has to be adjusted for a lower concentration of CO_2 in the flue gas (26). Additionally, gas turbine EGUs are more likely to be throttled for load-following applications than coal-fired EGUs, adding significant demands and stresses on the attached CCS system to ramp with the power plant (27).

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Currently, no commercial-scale IGCC plants are in operation or under development. The Kemper County, Mississippi, IGCC project struggled, with major problems stemming from overly complex technology, complex supply chain, and equipment reliability issues (28). After significant cost overruns, the original plan for a gasification plant was abandoned, and the plant was converted to natural gas operation (29).

TRANSPORTATION AND GEOLOGIC STORAGE

Several fundamental assertions are made by EPA in its proposed guidelines in relation to CO_2 transportation and geologic storage. In the following sections, those assertions will be directly addressed.

With respect to the geologic storage of CO_2, the proposed rule states that:

> *"The EPA proposes that CCS at a capture rate of 90 percent is the BSER for long-term coal-fired steam generating units because CCS is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources and that there are vast sequestration opportunities across the continental U.S." [page 33346]*

The issue is with the assertion that "CCS is adequately demonstrated" and "has been operated at scale." EPA describes in the May 23, 2023, technical support document (TSD) titled *GHG Mitigation Measures for Steam Generating Units TSD* on page 22 that there are only two large-scale CCS facilities in North America on existing coal steam EGUs. One of which was Petra Nova which only operated from 2017 to May 2020 and involved CO_2 EOR. The other is Boundary Dam in Canada, which is not subject to EPA's underground injection control Class VI rules for the storage of CO_2. To date, no commercially operated CCS project capturing CO_2 from a coal steam EGU in the United States has operated under EPA Class VI regulations. The only CCS projects that are in operation in the United States under EPA Class VI regulations are Archer Daniels Midland processing plant (capturing approximately1 million tonnes/year) in Decatur, Illinois, and the Red Trail Energy ethanol facility (capturing approximately 180,000 tonnes/year) near Richardton, North Dakota. For comparison, a 300-MW coal-fired facility would capture approximately 2.5 million tonnes/year. These two projects are not enough to demonstrate that the appropriate regulatory frameworks are in place for the operational phase of projects that will require flexibility and likely regular updates to permitted operational parameters.

Another issue is with the assertion of "vast sequestration opportunities." This assertation is seemingly founded on a geographic analysis performed by EPA:

"The EPA performed a geographic availability analysis in which the Agency examined areas of the country with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100-kilometer (km) (62-mile) area of locations with sequestration potential." [page 33298]

However, no documentation of this geographic analysis is provided. The May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD* also referenced this geographic analysis. Figure 1 of the TSD showing geologic storage potential from the NATCARB website includes an antiquated map layer for unminable coal seams. The U.S. Geological Survey (USGS) has a more accurate map of unminable coal seams that could be used for CCS (30). The USGS map accounts for EPA Class VI regulations, 40 CFR 144.3, and 40 CFR 144.6 (31), which prohibit CO_2 storage in formations with salinity lower than 10,000 mg/L (30, 32). Figure 1 of the TSD also shows an erroneous map layer for deep saline formations. Using the correct deep saline formation map layer (showing the proper extent of assessed formations based on minimum depth requirements), the USGS coal layer, and the pertinent stationary CO_2 sources will show that the spatial relationship of CO_2 capture to geologic storage is not as opportune as suggested by EPA. The result is that more and longer pipelines will be needed to transport captured CO_2 to feasible storage locations. This implication cascades into additional time (and money) needed to construct a fully integrated CO_2 capture, transport, and storage project. Other aspects of EPA's geographic analysis that contribute to the overstatement of "vast and nearby" geologic storage opportunities are:

- Proximity does not factor into the feasibility/suitability of geologic storage.

- The EPA geographic availability analysis is based on a generation unit being within 100 km of a state with geologic storage potential, rather than from the storage location itself, which erroneously oversells the spatial relationship between CO_2 source and geologic sink.

- The analysis does not integrate evolving local (state, county, parish) CO_2 transportation and storage laws, some of which are looking to ban the geologic storage of CO_2.

In the TSD, EPA states:

"DOE's assessment focuses on the potential physical constraints for sequestering CO_2; it does not include economic or other constraints."

And

"While the NETL and USGS characterize potential storage, site-specific technical, regulatory, and economic considerations will ultimately factor into the attractiveness of a given storage resource for a particular project."

These are nontrivial comments that have a strong impact on project timelines and budgets when a geologic storage option is pursued for captured CO_2. A major consideration from a regulatory perspective is access to federally owned pore space, a topic that has yet to be fully addressed by any federal agency.

TIMING

In the May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD,* EPA denotes that deployment of CCS is economically reasonable and can be done within 5 years:

> *"Deployment of CCS technology at EGUs involves a project schedule that can be completed in roughly five years. For affected sources who choose to implement CCS, the project will involve several phases, many of which can occur concurrently and simultaneously." [page 35 TSD]*

> *"There are many site-specific considerations to individual sources that influence the project timeline and schedule. Nonetheless, EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable." [page 36TSD].*

This 5-year period, as depicted in the example timeline shown in Figure 2, which was also presented in the TSD, is not realistic and is completely unachievable. The timeline has several issues related to the sequencing of events, as discussed below.

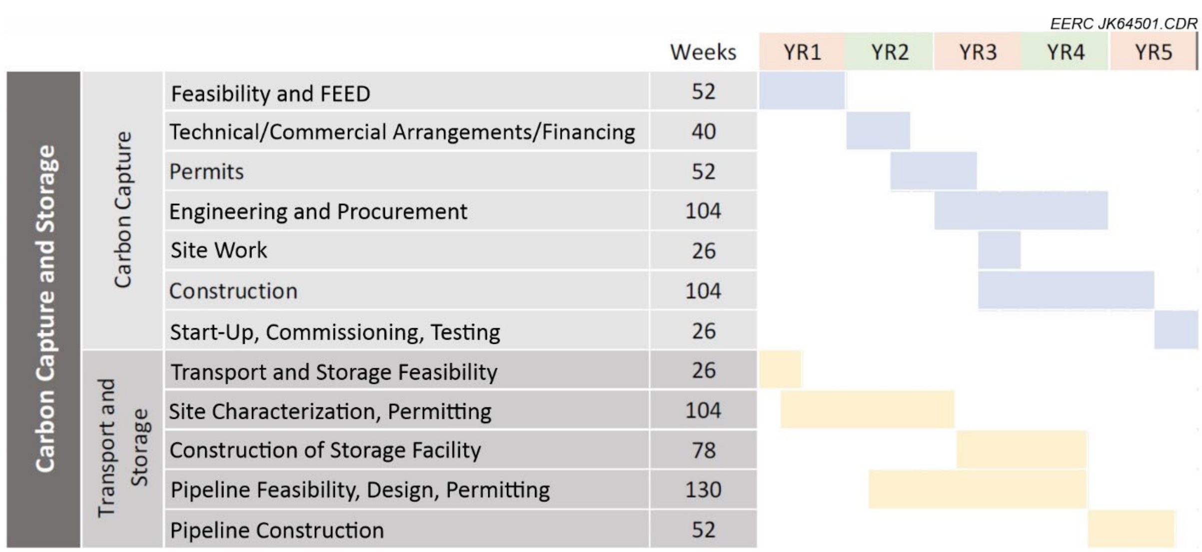

Figure 2. Timeline to storage as presented by EPA in the TSD.

Carbon Capture Timing Issues

This timeline assumes that procurement of capture equipment will be started prior to the storage site being permitted. Most facilities looking to develop CCS will be reliant on third-party financing or loans. These financing avenues have historically required permits for the storage site to be in place to increase regulatory certainty and reduce investment risks. Based on that experience, even on EPA's inaccurately short and overlapping time frames for each step, the carbon capture timelines would be delayed by at least an additional 1.5 years.

The timing of the site work and construction at the carbon capture site are shown to commence approximately 6 months after the start of engineering and procurement. Without detailed information concerning the constructability of the site such as soil analysis, location parameters (temperature changes, wind loading, etc.), the footprint of the capture facility, etc., that requires measurement and testing to provide detailed information for the construction of the capture facility, the present timeline is likely compressed and would be expected to require additional time (3–6 months) to complete the requisite evaluations prior to initiation of work.

Transport and Storage Timing Issues

The timeline shown in Figure 2 depicts 2.5 years for storage feasibility, site characterization, and permitting. This is an extremely optimistic and aggressive timeline. For example, the U.S. Department of Energy's CarbonSAFE Program assumes a 5-year timeline to address feasibility, characterization, and permitting. Even for states with Class VI primacy such as North Dakota, storage feasibility, site characterization, and permitting could take up to 4.5 years (33). One of the only ways to accelerate this timeline would be if there were existing site-specific data that were sufficient to address UIC Class VI requirements. For states without primacy, storage feasibility, site characterization, and permitting could take up to 6.5 years based on historical EPA permitting timelines from the two approved EPA UIC Class VI permits (34). In June of 2022, nine projects were waiting for Class VI permit approvals (35). EPA now has 98 UIC Class VI permits (in 35 projects) to review (36).

Another issue with the proposed 5-year timeline is that it does not adequately factor in the time needed to lease pore space. Much of the prime geologic storage opportunity lies beneath federally owned lands. As such, any storage operation that will emplace captured CO_2 in pore space managed by the federal government will need to work through federal permitting and NEPA (National Environmental Policy Act) review. This process alone can add years to a project's development timeline. In addition to the federal land issue, many states have yet to address pore space ownership. Challenges to amalgamation authority on nonfederal land, achieving 100% consent of private pore space owners where amalgamation rules do not exist, and states lacking established pore space rules result in significant uncertainty regarding how much of the nation's geologic CO_2 storage resources can be developed and permitted, particularly within the time frame of the proposed rules.

Pipeline feasibility, design, and permitting stage is listed at 2.5 years. Depending on the route of the pipeline, permits for water body crossings, federal lands, and the Army Corps of Engineers can take a year or more to acquire, if the permit is allowed at all. In addition, agreements with landowners for rights of way (ROWs) for the pipeline can take a year or longer, depending on the length of the pipeline. In all, the listed time of 2.5 years for pipeline feasibility, design, and permitting appears to be overly optimistic. In addition, with the current supply chain issues, the ability to secure the required piping and equipment may take up to 1 year to acquire. With multiple major projects planned to be undertaken, supply chain issues would be expected to worsen. Finally, as the number of projects grow, the demand for labor will increase, adding to the expected cost.

A subsidiary supporting attachment provided by EPA to augment the *GHG Mitigation Measures for Steam Generating Units TSD* entitled "CCS Schedule Sargent and Lundy" contains the development timeline in Figure 3. As stated in the supporting document, "This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO_2 off-take/storage (including transportation, sequestration, EOR, utilization, and/or utilization)." Although the 7-year schedule shown in Figure 3 is quite aggressive, it is more realistic than the EPA's schedule shown in the upper part of Figure 2. There is no explanation as to why EPA chose to arbitrarily dismiss this timeline in favor of one that seemingly fits its regulatory goals better.

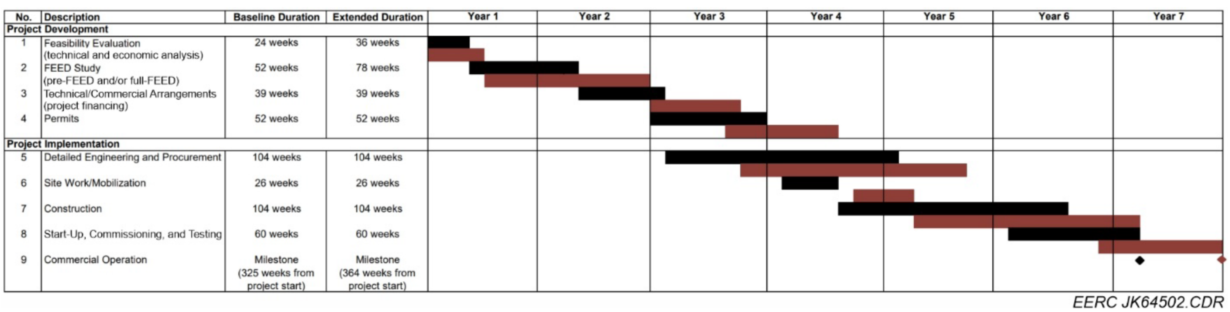

Figure 3. More realistic development timeline for the capture portion of a CCS project.

COSTS

It is difficult to give precise costs for a CCS project because of the factors outlined above and the specific needs of a specific facility to achieve a minimum of 90% CO_2 capture. It has been our experience that the general range for the capture facility at EGUs alone is \$0.8–\$1.3 billion. In determining the needs for CO_2 transportation, a "rule-of-thumb" (ROT) estimate for the installed cost of a pipeline can be calculated with the following expression:

Installed Cost = Pipe O.D. (inches) × Pipeline Length (miles) × \$100,000

This ROT estimate is a based on the FECM/NETL CO_2 Transport Cost Model (2022) (Model), where the installed cost reflects 2019 dollars and is based on the Parker equation within the central U.S. region, referenced within the Model. Pipelines in other areas as well as any pipeline specific needs (environmental impacts, water body crossings, large elevation changes, etc.) would need to be addressed in addition to the estimated costs provided by the Model. The Model reflects costs for new pipeline installations and reflects the steel pricing used within the model. If the pricing of steel for the pipeline under consideration is different than the pricing included in the Model, the Model would need to be adjusted to reflect the current pricing or additional cost included to reflect the anticipated pricing.

EPA references $280K per inch-mile for pipeline installations and states that is the cost "to construct new natural gas pipelines ("laterals") and is an average for lateral development within the contiguous U.S." (page 33353). The term "lateral" typically refers to a line that delivers product from a main line to a customer. As such, the installation of a lateral will normally include costs such as hot tapping of the main line to install the lateral offtake, potentially shutting down the main line to install the lateral offtake, etc. These are high-cost projects and are not typically included in new pipeline construction.

From our experience in CCS field development, using an example of one injection well with one monitoring well, assuming the CO_2 is at pressure and not requiring additional pressurization at the injection pad, and injecting 1 million metric tons of CO_2 per year, the cost of injection field development surpasses $30 million. Additional injection and monitoring will cause this value to quickly increase. Also, the need for premium casing such as corrosion-resistant alloys (CRAs) can add substantial cost to the drilling costs associated with the injection and monitoring wells necessary for the project. In addition, the lead time for the CRA material can be 1 year or longer. If material testing is required to determine which CRA would best serve the system, the time to design, perform, and evaluate the material tests can require 6 to 12 months (depending on the number and types of materials for testing) before the CRA material can be purchased. Given the wide range of CO_2 streams from the EGU and other facilities, different targeted injection horizons, and very little information available on CRA testing in saline environments with CO_2 streams with multiple impurities, it is anticipated that material testing would be required to determine which CRA material would be required. The effects that the material testing needs and the availability of CRAs would have on a project are not evident in EPA's consideration.

SUMMARY

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. No large-scale (greater than 240-MW) CCS systems on EGUs are in operation in the United States by which to determine the feasibility of CCS as a BSER option. Each facility's design considerations are unique and can vary widely due to variables such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, ramping due to load changes, and the required purity of the CO_2 emission stream. When examining the case of Boundary Dam Unit 3 capture facility's availability factor, since the start of operation, the expectation of a capture facility to operate long enough through the year to meet EPA's proposed annual emission requirements has fallen short, and there is no expectation that facilities in the United States will not see similar issues. The EPA storage assumptions are not adequately documented, and the complexity of the permitting required will greatly affect timelines for facilities to implement CCS. Based on the supported conclusions and the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

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Attachment E

Analysis of Post Combustion CO_2 Capture, Transport and Storage Costs in the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

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August 3, 2023

Executive Summary

The EPA issued proposed rules for greenhouse gas (GHG) mitigation from the electric power generating sector under Clean Air Act Section 111 ("proposed rules") in May of 2023. While these proposed rules include alternative potential compliance methods, including retirement, for achieving the targeted GHG reductions, the focus of this analysis will be the cost of implementing post combustion CO_2 (carbon) capture and storage (CCS) in natural gas- and coal-fired applications.

In the proposed rules, natural gas combined cycle (NGCC) power plants opting to implement CCS would be required to do so by 2035 and coal would be required to implement CCS by 2030. As part of its determination of which is the "best" system for emissions reduction (BSER), the EPA has an obligation to consider cost. Consequently, the EPA has provided technical support documents to determine the cost of CCS implementation in coal- and gas-fired applications.

However, the technical support documents are inconsistent with each other, as well as the many references from which the EPA selectively retrieves costs without appropriate context and without noting key differences in many modeling assumptions. Furthermore, the EPA does not adequately address how the social cost of carbon is calculated, what modeling assumptions were used, and how these costs compare to much more representative cost modeling associated with real plants in various regions across the United States operating in a very complex interconnected electrical generation, transmission, and distribution system.

In addition, the EPA fails in its cost modeling to adequately address how the Internal Revenue Code (IRC) section 45Q tax credit works in practice. The tax credit is a credit against income tax, but the EPA treats it as a direct and immediate discount to the cost of building and operating a CCS system. Such treatment shows that the EPA has failed to accurately apply basic financial modeling or account for the actual regulations of other federal agencies.

For these reasons, the only possible conclusion is that the EPA is significantly underestimating the cost of compliance of this proposed rule, using flawed modeling and a lack of a transparent social cost of carbon.

Modeling and Cost Inconsistencies Applicable to Natural Gas and Coal-Fired Applications

In docket EPA-HQ-OAR-2023-0072, the EPA provides two primary technical support documents regarding CCS. The first, *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* applies to NGCC applications over 300 MW.[1] The second is for coal

[1] *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines*, Accessed 7/7/23, Available at: https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20GHG%20Mitigation%20Measures%20for%20Combustion%20Turbines.pdf

applications, *Greenhouse Gas Mitigation Measures for Steam Generating Units*.[2] Both documents provide technical explanations and cost modeling for CCS in their respective applications.

However, there are some glaring inconsistencies. First, the assumed cost of transportation, storage, and monitoring (TS&M) is assumed to be $10/ton in natural gas-fired applications, but $30/ton in coal-fired applications. Clearly, a ton of CO_2 meeting the same pipeline quality specification should cost the same to transport, store, and monitor, regardless of the source. Such a blatant, threefold inconsistency in the same number in the two primary technical support documents indicates that the EPA has inexplicably failed to apply consistent methodologies for addressing the same question, resulting in glaring inconsistencies that lead to arbitrary and capricious results and analyses. Given the importance of such a regulation, the EPA should at least hold itself (and be held) to the most basic standards of consistency, which have not been met in this proposed rule.

Furthermore, in both cases, the EPA cites the National Energy Technology Laboratory's (NETL) *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs* (QGESS).[3] That study is stated in 2018$ and there is no evidence that the EPA costs have been updated to 2023$, which would be subject to a 21.1% cost increase due to inflation. Thus, not only has the EPA used vastly different numbers, but these costs are also significantly discounted related to the costs that would be incurred in 2023.

In addition, the referenced QGESS report finds that the four geological formations in the study have a broad range of characteristics that affect cost of injection of CO_2 and the capacity of the formation to accept CO_2. The EPA technical documents do not acknowledge the wide range of costs associated with injection depending on geography and geologic conditions, and EPA instead simply assumes a single cost number for injection and a single 100 km transportation distance. With those generalizations, it is impossible to determine how either $30/ton or $10/ton are extracted from the referenced QGESS document. The numbers appear to be completely arbitrary and yet are extrapolated to the entire country.

As an example, the referenced QGESS document studies include geologic assessments in Illinois, North Dakota, Wyoming, and Texas. The first-year break-even cost of injection, not including transportation costs, varied from $8.32 to $19.84 per metric ton of CO_2. These four geological formations are all in the central part of the United States. As such, the EPA's assumed 100 km transportation distance fails to adequately account for the actual distance necessary for most CO_2 to reach a sequestration site from existing or new generation sites throughout the country, as well as the variability within the country on storage costs. In the case of the NGCC technical supporting document, the EPA assumes a $10/ton cost to transport and store CO_2, when in the same QGESS document referenced by the EPA, the federal government's own data indicates double that cost just for storage without any transportation of CO_2 in Montana.

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[2] *Greenhouse Gas Mitigation Measures for Steam Generating Units*, Accessed 7/7/23, Available at: https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20GHG%20Mitigation%20Measures%20for%20Steam%20EGUs.pdf

[3] *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs*, Accessed 7/7/23, Available at: https://www.netl.doe.gov/projects/files/QGESSCarbonDioxideTransportandStorageCostsinNETLStudies_081919.pdf

It should also be noted that the QGESS costs do not specifically mention a direct cost for accessing the pore space. Pore space owners will require compensation for allowing a company to utilize that property, and this fact and associated cost are not adequately identified or included in the EPA's documents. Significant variability could be expected in terms of pore space lease fees associated with surface ownership rights, as it cannot be guaranteed that surface rights landowners would be willing to lease subsurface storage rights at a given cost, or if subsurface rights could even be procured due to landowner concerns.

Finally, as has been publicly demonstrated in Iowa, recent attempts to build CO_2 pipelines to industrial facilities have met severe resistance.[4] The EPA's notion that a 100 km CO_2 pipeline is feasible for all units not only ignores the geographic reality that most power plants in the country are further than 100 km from a storage site, but also erroneously assumes that pipelines crossing private property would be feasible, guaranteed, or constructed in the proposed timelines required.

Fundamental Flaws in Cost Modeling

The EPA also has fundamental flaws in cost modeling that apply to both natural gas- and coal-fired applications. In both the natural gas- and coal-fired technical support documents, the EPA provides various cost estimates and models for various applications. The EPA also has fundamental flaws in cost modeling that apply to both documents. Additionally, every single example that the EPA provides assumes that the enhanced IRC Section 45Q tax credit provides an immediate $85 per metric ton discount to each metric ton of CO_2 captured and securely stored. The EPA also does not acknowledge the severe barriers to obtaining, transferring, and utilizing the tax credits that would reduce that value for unit owners and thus result in higher than assumed costs.

EPA Cost Estimate Flaws in Coal Fired Applications

In the technical support document, *Greenhouse Gas Mitigation Measures for Steam Generating Units*, the EPA references a report by the Global CCS Institute (GCCSI), *Technology Readiness and Costs of CCS,*[5] indicating that costs of CCS on coal-fired applications have been steadily dropping and would approach $50 per metric ton by 2025. However, this was assuming a 90% generating capacity factor for coal-fired units and 100% availability of their capture system in the GCCSI report. In contrast to the 90% generating capacity factor used in the GCCSI modeling, the EPA's modeling used a variety of capacity factors, including 40% and 70% for the host unit, while assuming that the capture system has 100% availability when the host site is running. The Energy Information Administration's (EIA's) measured and recorded capacity factor data indicates an average coal-fired capacity factor of 47.8% for the year 2022.
As the EPA concedes, increasing unit capacity factors substantially decreases the cost per ton of CO_2 captured. Therefore, the EPA's referenced $50 per metric ton of CO_2 captured is not

[4] "Iowa House passes new limits on when carbon pipeline companies could use eminent domain," Accessed 7/19/2023, Available at: https://www.desmoinesregister.com/story/news/politics/2023/03/22/iowa-house-passes-bill-restricting-eminent-domain-to-build-pipelines/70035687007/

[5] *Technology Readiness and Costs of CCS*, Accessed 7/7/23, Available at: https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf

reflective of its own modeling parameters (i.e., capacity factor), much less real-world conditions. The EPA should not cherry pick costs completely out of context from independent reports to justify its rules. Instead, the EPA should reevaluate its cost models using a consistent methodology and consistent capacity factor assumptions based on real data, rather than hypothetical reports with significant differences in baseline assumptions.

Additionally, the EPA's and GCSSI's assumptions related to 100% availability of CCS systems is fundamentally flawed. For example, the EPA justifies CCS on coal units as BSER by referring to Sask Power's Boundary Dam project in the EPA's *Greenhouse Gas Mitigation Measures for Steam Generating Units* technical support document. The EPA states, "In the 4th quarter of 2022, the CCS unit was available 78.9% of the time and had exceeded its target availability of 75% for three consecutive quarters." On the other hand, if a capture system is only available 75% of the time, clearly the 90% coal unit capacity factor as assumed in the referenced GCCSI model is impossible and should not be referenced in the first place.

Such limited capture system availability also makes even a 70% capacity factor for the host plant highly improbable. The proposed rule by the EPA would require the capture system to be available whenever the host site generates power to achieve 90% capture of CO_2 emissions. If the capture system has an availability of 75%, the absolute maximum capacity factor for the host site would be 75%. An availability of 75% for the CCS system means that the power plant is not allowed to operate 1 in 4 days, or for 91.25 days per year, in a best-case scenario. This poor availability of the CCS system should be used to reference why CCS is not BSER, rather than why it is BSER. Based on the EPA's proposed rule, it is unlikely that Boundary Dam's current performance would be in compliance with the proposed rule without significant limitations to its capacity factor.

This challenge with inconsistent capture system availability and modeling over a wide range of host unit capacity factors also ignores some very real technical challenges implicit in the capacity factor numbers. As the EIA reported, the 2022 average capacity factor for the coal fleet was 47.8%. This indicates that coal plants are not operating at high capacity factors and are also operating at part load or in load following modes. The EIA's data reflects this reality, that actual coal-fired power plants operate in a dynamic mode on a dynamic grid where they may be required to operate at near 100% capacity factor or 40% capacity factor, depending upon the needs of the grid at any given time.

When this happens, the partial pressure of the CO_2 in the flue gas fluctuates and is reduced under low load conditions, typically also accompanied by a reduction in efficiency and higher heat rate. When units change load, the partial pressure of CO_2 changes. At lower load in coal plants, the CO_2 concentration or partial pressure decreases as less fuel is burned to generate a smaller amount of steam. At the same time, the amount of air blown into the boiler does not decrease in direct proportion to the decrease in fuel flow. This is because a certain volume of gas is needed to flow through the boiler to maintain appropriate steam temperature balance and other criteria necessary to ensure adequate operation of the plant. The result is a more dilute CO_2 stream that still must be captured at 90%. While the referenced GCCSI report may erroneously assume a 90% coal unit capacity factor in its cost models, the report does provide a detailed explanation of why CO_2 capture costs increase with decreasing partial pressure of CO_2. However, the EPA does not acknowledge that each plant operates in a dynamic environment. The models the EPA uses or references in its technical support document are spreadsheet models assuming constant heat rate, constant CO_2 concentrations, and constant load. The EPA's models fail to reflect the reality of variable coal unit capacity factor operations and are, therefore, inapt tools for assessing the costs or technical viability of CCS in real world conditions. This is a reality of physics, but is neglected by the EPA's cost analysis, which assumes impractical, and misrepresentative static operating conditions not found in real life operation. In doing so, the EPA has not acknowledged real-world operation which will drive up capture costs, but instead cherry picked a number from operation conditions that the EPA has proven is not attainable.

Furthermore, the EPA makes no mention of how the BSER implementation would impact this very valuable grid service of dispatchable synchronous generation which is critical to balance the addition of intermittent inverter-based resources, such as wind and solar, on the grid.

Unfortunately, the EPA is inconsistent in its financial models in terms of baseline assumptions related to coal unit and capture system operations, and does not try to normalize any of the data. Regrettably, where the EPA was consistent in its analysis, it was by erroneously assuming static operating conditions that misrepresent the utilization of the coal fleet in the current electrical grid. These assumptions lead to an underestimation of costs related to CO_2 capture. The EPA should use practical and normalized assumptions and data to understand the actual cost implications of installing CCS on the fleet. Only then will it be possible to determine whether there is appropriate cost justification.

EPA Cost Estimate Flaws in Natural Gas Fired Applications

Unfortunately, the EPA also uses multiple models with varying assumptions in the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document, which leads to a muddled mishmash of inaccurate cost assumptions. For example, the document cites the NETL report *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (DOE/NETL - 2023/4320, October 14, 2022),[6] which makes several critical assumptions on pages 33 and 34, indicating that the costs of a greenfield site are a best possible scenario.

The site is said to have rail access, adequate municipal and ground water resources, an elevation of sea level, level topography, relatively low temperature cooling water of 60°F, and Midwest labor rates. This is not adequately representative of the existing fleet or proposed natural gas units that would be subject to these rules.

For example, the generic Midwest location cited in this report is not subject to extreme heat, hurricanes, an arid climate or lack of water, extreme cold, seismic zones three or four, high labor costs or shortages, lack of real estate, geographic constraints, challenging geology, or any other factors that will drive up cost significantly. Any existing or new unit will inevitably be located

[6] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (DOE/NETL - 2023/4320, October 14, 2022), Accessed 7/7/23, Available at: https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

above sea level and as high as 6,780 feet. The report may be reasonable for determining the least cost of CCS in a greenfield site, but it is not useful or reasonable to extrapolate those least cost values to the incredibly diverse climates and conditions that vary drastically throughout the United States, particularly for existing natural gas units located in disparate regions throughout the country with fundamentally different baseline conditions.

It does not appear that the EPA seriously considered the cost impacts of actual CCS implementation at real sites beyond mention of several front-end engineering design (FEED) studies. However, when the EPA referenced the FEED studies, it did not acknowledge the significant cost impact associated with implementation of CCS at an actual site.

As an example, the EPA provides its own cost estimates for CCS for new combustion turbines in Figure 7 of the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document with the following assumptions: "12-year amortization, 7 percent interest rate, $3.69/MMBtu natural gas, $85/tonne tax credit, 75 percent capacity factor, and $10/tonne TS&M cost."

First, the $85/ton tax credit (which, as noted previously, is an overestimate and not guaranteed) is only valid for 12 years. Any plant that is built or retrofit would be run for considerably longer than 12 years, at which point the tax credit expires. It also assumes that the host unit is able to operate at a capacity factor of 75% – requiring at least a 75% availability rate for the capture unit – in its first year of the capture system operation, which has never before been achieved. As previously discussed, Boundary Dam's capture system achieved 75% availability, which would translate to less than 75% capacity factor, 8 years after commissioning its CCS system. Therefore, the EPA's assumption of a 75% host unit capacity factor in the first year of operation, and still being compliant with the proposed emission limits, is completely unreasonable and invalid. Also, as previously discussed, the cost of TS&M is likely to significantly exceed $10/ton – perhaps by 300% or more at $30/ton– and the EPA completely neglects to show the cost of abatement when the tax credit expires.

Furthermore, the EPA in Figure 9 of the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document provides the following assumptions when calculating costs for retrofit CCS NGCC costs: "7 percent interest rate, $3.69/MMBtu natural gas, $10/tonne TS&M costs, $85/tonne tax credit for 12-year amortization, and $45/tonne tax credit for 30-year amortization." It should be noted that currently such a $45/tonne tax credit does not exist. The EPA has no basis whatsoever to assume potential tax incentives of amounts and durations that have not been written into law.

There has not been a single large pilot or commercial demonstration of any CCS technology, including secure geologic storage, at any natural gas-fired plant in North America. Therefore, the EPA cannot claim that any financial, cost, or performance models or assumptions have been validated by any projects in North America. The EPA also cites a number of FEED studies as evidence to why the best system of emissions controls exists. However, the EPA misunderstands or fails to consider the cost information included therein.

For example, the EPA cites the Mustang Station FEED study for a capture system at an existing NGCC unit. The FEED study estimated a cost of CO_2 captured (not including TS&M) of almost $170/ton, assuming a 10% internal rate of return and at the plant's current 52% capacity factor. Even at an 85% capacity factor, which is not achievable, the cost of capture would still come to $85/ton.[7] This example illustrates how site-specific conditions can create significant cost escalation. In the case of Mustang Station, the lack of additional water sources required dry cooling for the CO_2 capture system. This not only created a significant increase in cost, but also shows that the EPA has completely overlooked the water resource requirements of implementing CCUS in their analysis. The EPA must account for these sorts of costs in its cost estimates.

EPA's Misrepresentation of the 45Q Tax Credit

The EPA assumes that the tax credit is immediately applicable to the project, and cuts a flat $85/ton off the cost of captured and stored CO_2. This is a gross misrepresentation of the 45Q tax credit and how the credit is issued, obtained, traded, and monetized in reality. Even with the direct pay provisions passed by Congress, the EPA's methodology is not how the 45Q tax credit functions.

The EPA has assumed that every project can meet all requirements of the enhanced 45Q tax credit, which is not necessarily a valid assumption. In order to qualify for the "enhanced" 45Q tax credit rate outlined in the Inflation Reduction Act, entities must complete a variety of apprenticeship, prevailing wage, and domestic content requirements. While waivers are available, the EPA just assumes that all of the necessary conditions will be met by each project in each jurisdiction. The EPA also does not assume any cost borne by the owner of a project to comply with these significant reporting and compliance requirements.

Further, the assumption that the credit is directly paid and instantaneous shows that the EPA misunderstands (or misrepresents) basic tax law or financial modeling. Even with the direct pay provision, only municipalities and cooperatives would qualify for direct pay from the Treasury for the 12-year credit duration, which is a small percentage of the overall fleet. The remainder of the fleet would require a tax credit posted against federal income tax for 7 of the 12 years of the credit duration. Given that many of these projects will be generating $100 million or more in tax credits annually, it is highly improbable that the project owner or utility owner would be able to directly utilize the tax credits internally, especially for those with multiple units. For example, a relatively small 400 MW coal plant with an 80% capacity factor would generate $255 million in annual tax credits, which would far exceed any income tax generated by the unit.

Instead, the utility will need to transfer some of the tax credits to a tax equity investor who will be able to utilize the tax credits. This assumes that a tax equity investor is willing to invest in the project with technology that is not currently running in the United States and has never operated at the rate, scale, and consistency required under the EPA's proposed rules.

[7] *Piperazine Advanced Stripper Front End Engineering Design*, Available 7/10/2023, Accessed at: https://netl.doe.gov/projects/files/Piperazine%20Advanced%20Stripper%20(PZAS™)Front%20End%20Engineering%20Design%20(FEED).pdf

Additionally, the process for negotiating and agreeing to such a tax equity arrangement could take months, if not years, and would likely need to be finalized before project financing can be secured. This would likewise impact the ability of the project or utility owner to receive the assumed benefits of the tax credit and would delay construction and operation of the capture unit, assuming the tax equity deal could be finalized in the first place. Furthermore, the number of tax equity investors who can utilize $255 million in annual income tax credits will likely be a much smaller number than the number of coal and gas plants potentially impacted by this proposed rule. The EPA completely ignores the difficulty faced by a utility to secure financing and the requisite tax equity investment, which will be critical to raising the necessary capital to build a CO_2 capture system. As a result, there is no possible way that each plant impacted by this rule could possibly secure the necessary financing and tax equity investment required to comply at costs that are even close to what the EPA has suggested.

Plants that can complete this regulatory and financing gauntlet will still face additional transactional costs, which the EPA ignores. Assuming a project can move forward and is able to secure a tax equity investor, the tax credit will be transferred from the project owner to the tax equity investor. When this occurs, there will be a transaction cost, as no tax equity investor will go through the exercise without receiving a return on investment for procuring the tax credits. With a wide range of secure and low- to no-risk investments offering 4.5% to 5.35% rates of return in July 2023 at current interest rates, it is reasonable to assume that a minimum 10% and more realistically a higher transaction cost would be associated with the transfer of the tax credit, thus immediately reducing the credit value from $85 to $76.5 per metric ton to the CCS system owner.

Furthermore, the misleading benefit of the credit by the EPA also neglects the impact of time. Even in years when the CCS system owner may qualify for the direct pay provision, the payment is not immediate. The ton of CO_2 must be verified by either the EPA Subpart RR or ISO 27914 and submitted to the Treasury. Upon approval from the Treasury, a check may be issued on a quarterly basis. As a result, the system has been operating, capital payments are being made, and CCS operational system costs are being incurred for an absolute minimum of 91 days. Therefore, the CCS system owner must continue to pay down the debt associated with the CCS system, while waiting for compensation of the tax credit or direct payment.

The EPA acknowledges in some of its financial modeling that there is a difference between "overnight costs" and "total as spent" costs, and that many activities, like construction, are not instantaneous and result in costs related to interest being accrued over time. However, the EPA neglects this same reality when it comes to receiving the direct payment, which will happen, at most, quarterly. On a 7% annual interest rate, this effectively creates a 1.7% discount quarterly of the revenue from 45Q. Therefore, the best case is for a direct payment equivalent to $83.55 per metric ton. But, even that would only apply to a small fraction of the impacted generating units owned by municipalities and cooperatives. The majority of units are owned by investor-owned utilities which would not qualify for the full 12-year direct pay provision.

The fact that the EPA does not apply this same basic financial modeling principle to the tax credit as was applied to construction costs of the CCS system indicates that the EPA is fundamentally contradictory in its modeling assumptions. Furthermore, while 1.7% may not seem significant, it is part of a broader pattern of compounding assumptions that lead to a very significant underestimation of compliance costs that will be directly borne by the electricity consumer.

The EPA needs to fundamentally change its financial modeling to account for the very significant hurdles, as well as costs associated with financing, building, and operating a CCS installation.

Conclusions

The EPA has not sufficiently modeled the cost of CCS implementation, nor has the EPA sufficiently modeled the impacts of adding CCS to the existing fleet in terms of grid impacts, cycling capabilities to meet the needs of an increasing renewable energy penetration grid, water use and impacts, and technological readiness.

The EPA should perform an adequate analysis to determine how the technology required will impact the operation of the grid, and what it will cost in a variety of regions throughout the country, all of which will be significantly impacted by this regulation.

Instead, the EPA has used fundamentally flawed models which do not use consistent baseline assumptions. Their assumptions use conflicting costs for CO_2 transportation, storage, and monitoring. The assumptions use capacity factors that are not reflected in the actual capacity factor data from the EIA, extrapolate the least cost construction environments to the entire United States without any acknowledgement of how location substantially impacts costs, completely misrepresent the impact of the 45Q tax credit in financial modeling, and provide conflicting examples of BSER projects, which would likely not even comply with the proposed rule as justification for the rule.

About the Authors

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Dr. William Morris completed his Ph.D. and M.S. in chemical engineering at the University of Utah, examining the effect of pollutants such as NO_X, SO_X, and particulate matter on aerosol formation in air and oxy-fired combustion for CO_2 capture. He also holds a coordinate A.B. in Physics and Environmental Studies, with a minor in History from Bowdoin College. He is currently president and technical director of Carbon Management Strategies LLC. He is also contracted by the Wyoming Energy Authority (WEA) as Program Director to provide engineering and business development support services for CO_2 management technologies testing at the Wyoming Integrated Test Center (ITC). The ITC facility is a public/private venture between Basin Electric Power Cooperative, Tri-State G&T, the National Rural Electric Cooperative Association, Black Hills Power, and the state of Wyoming through the Wyoming Infrastructure Authority. The research facility can provide up to 23 MW equivalent of flue gas for large pilot post combustion CO_2 capture testing, as well as 6 small 0.4 MWe test bays which have hosted the NRG COSIA Carbon XPRIZE CO2 utilization competition as well as a post combustion capture system from TDA Research. Additional projects in the procurement phase are Kawasaki Heavy Industries solid adsorbent technology, Membrane Technology and

Research's 180 tonne per day membrane CO_2 capture facility, and another 24 ton per day membrane capture system led by Gas Technology Institute and the Ohio State University.

As an employee of ADA Environmental Solutions, Dr. Morris worked in the areas of mercury emissions control, CO_2 capture, NO_X control, and is the listed inventor on 3 issued NO_X, mercury, and CO_2 emissions control patents, as well as other patents pending. He was also a contributing author to the oxy-fuel combustion section of the National Coal Council's report, *Fossil Forward,* in 2015 for then Department of Energy Secretary of Energy, Ernest Moniz, providing an update on CO_2 capture technologies. In addition, he was the CO_2 use chapter co-lead with Professor Alissa Park of Columbia University for the National Petroleum Council's report, *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. He has conducted basic research, small pilot research, and commercial scale demonstrations and trials of various mercury, NO_X, and emissions control technologies with both private industry and universities. Commercialization success included developing a novel coal treatment process to qualify for the IRS section 45 refined coal tax credit, which produced approximately $1.8 billion in tax credits. Previous partners have included University of Utah, University of California Berkeley, Texas A&M University, Lehigh University, Southern Company, Aspen Aerogels, The University of Akron, the Electric Power Research Institute, the National Energy Technology Laboratory, the U.S. Department of Energy, and other private industry companies. In addition, he has been a peer reviewer for the journals of American Chemical Society as well as Elsevier Publishing.

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having “all of the above” energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment F

Analysis of the EPA’s Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives

Regarding: EPA’s Proposal entitled “New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule”
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. John Weeda, Quail Hollow, LLC

August 3, 2023

Executive Summary

Attempted compliance with the EPA's proposed greenhouse gas regulations for new and existing power plants will have a serious impact on the reliability of the electricity grid based on testimony from the Federal Energy Regulatory Commission (FERC), assessment of reliability by the North American Electric Reliability Corporation (NERC), and regional assessment by the Center for the American Experiment.

Shutting down existing fossil fuel resources, driven by compliance requirements of the EPA's proposed rule, would result in a massive need for renewable energy. This generation is geographically distributed and weather dependent, requiring the need for massive investment in transmission infrastructure and affecting the economics associated with investing in alternative technologies in an effort to keep the electric grid functional and reliable. These investments are expected to amount to trillions of dollars per region of the country and involve huge construction, putting unprecedented demand on labor and materials.

Assessments of Generation Resource Impact

The EPA's proposed regulations would set strict carbon dioxide (CO_2) limitations for gas- and coal-fired units based on installation of carbon capture and storage (CCS), fuel switching to natural gas or hydrogen, and/or committing to major limitations as follows:

- Compliance options for existing coal-fired units:
  - Commit to retire prior to January 1, 2032 – Maintain current level of performance/emission rate; no other compliance action required.
  - Commit to retire prior to January 1, 2035 – Maintain current level of performance/emission rate; limit annual capacity factor to 20% maximum beginning January 1, 2030.
  - Commit to retire prior to January 1, 2040 – Reduce emission rate by 16% beginning January 1, 2030, based on co-firing 40% natural gas.
  - No retirement – Reduce emission rate by 88.4% beginning January 1, 2030, based on 90% removal with CCS.

- Compliance options for existing gas-fired units (applies to units of 300 MW or larger with an annual capacity factor of 50% or more):
  - Two options for compliance:
    - Clean hydrogen: 30% co-firing by January 1, 2032, 96% by 2038, or
    - CCS: standard assumes 90% capture rate by January 1, 2035.

The technologies for CCS are in their infancy of commercialization and should not be considered the Best System of Emissions Reductions (BSER) at this time. In any event, even if CCS were demonstrated and generally achievable, it is next to impossible for any coal-fired unit that had not already started the process of design or construction of CCS, even before EPA proposed the rule, to construct CCS by January 1, 2030. So the CCS option, at least for coal-fired power plants, is illusory. It is also largely illusory for gas-fired combustion turbines. Fuel switching to natural gas is not practical for many generators due to lack of access to natural gas and other technical difficulties associated with each unit design. For example, with respect to the latter, adding or increasing flue gas recirculation will be needed and adding hundreds of horsepower. Heat transfer in the boiler surfaces would be affected, requiring modification or addition of heat transfer surface. The exit gas temperature from the boiler would typically increase, causing shortened life of the equipment at the back of the boiler and downstream. The heat rate measure of unit efficiency is typically negatively affected. A detailed engineering analysis would have to be completed by each generation owner to determine the feasibility of a gas conversion. In summary, these changes that affect the efficiency of the generation are contrary to progress that the industry made for many years of increasing efficiency to get more electricity for the customer at a lower cost. These challenges are discussed in the Babcock Power Services publication "Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers."[1]

The alternative use of hydrogen as a fuel for combustion turbines is not practical due to current lack of fuel availability, high cost, and the need for long-term demonstration of the technology in existing generators. Prior to any mandated new buildout of hydrogen generators, the equipment manufacturers must demonstrate reliability and drive down the cost of the equipment. For further details on this topic, please see related comments on hydrogen.[2]

Reliability and Resource Adequacy Concerns

The Federal Energy Regulatory Commission (FERC) has raised the alarm to Congress in recent testimony about the continued loss of dispatchable generation without sufficient and adequate replacement: "There is a looming reliability crisis in our electricity markets," FERC Commissioner James Danly said. "The United States is heading for a very catastrophic situation in terms of reliability," FERC Commissioner Mark Christie said. FERC Acting Chairman Willie Phillips said, "We face unprecedented challenges to the reliability of our nation's electric system." The full recording of the FERC testimony to Congress is available online.[3]

At another Congressional hearing, North American Electric Reliability Corporation (NERC) CEO, Jim Robb, was asked whether renewables and transmission could sufficiently replace generation assets forced to retire early as a result of EPA regulations. Robb stated flatly "No. Not in the timeframe we're looking at." PJM Interconnection CEO, Manu Asthana, similarly stated

[1] Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers.[1] Jason C. Lee, P.E. and Michael Coyle, Babcock Power Services, Inc. Presented at ASME Power Conference July 2014, Baltimore, MD, https://www.babcockpower.com/wp-content/uploads/2018/01/leveraging-natural-gas-technical-considerations-for-the-conversion-of-existing-coal-fired-boilers.pdf

[2] *Analysis of Hydrogen in Combustion Turbine Electric Generating Units*. *Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (Docket EPA-HQ-OAR-2023-0072)*, Doug Campbell, August 3, 2023

[3] https://www.energy.senate.gov/hearings/2023/5/full-committee-hearing-to-conduct-oversight-of-ferc

that "we need to hang on to resources we have today that work, until their replacement is here," and that the EPA's proposed greenhouse gas regulations for power plants "will continue to push this generation off the grid." The full recording of this testimony to Congress is available online.[4]

NERC prepares reliability reports each summer and winter season. The last three reports have cautioned that large areas of the country are at risk regarding reliable electric supply. Recently, winter storms Uri and Elliot have shown that the reliability and resilience of the electric grid with the current generation fleet are not adequate to keep electric supply to customers in adverse conditions. Furthermore, this current fleet is much less weather dependent than the proposed decarbonized fleet. A detailed review of NERC assessments is available online.[5]

On a regional level, regional transmission organizations (RTOs) and independent system operators (ISOs) are increasingly calling attention to the rapid retirement of baseload, thermal resources as a result of government policies, private sector actions, and economics. Forward-looking studies of the resource adequacy of the electric grid commissioned by the North Dakota Transmission Authority have examined addition and retirement of resources in both the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) regions of the country, with a projection of which resources are likely to shut down as a result of the cost of compliance with the EPA's coal combustion residuals regulations and Ozone Transport Rule.[6,7] These studies[8] show that by 2026, neither MISO nor SPP will have adequate dispatchable resources to meet peak load demand. In other words, the grid will require dispatchable and reliable resources and favorable weather conditions to operate weather-dependent resources to even meet the peak demand. Before the end of the decade, these weather-dependent resources may be required to provide over one-third of the generation to meet those peak demand times in the SPP region. This concern is clearly a contributing factor to FERC and NERC raising the alarm that our reliable electric grid is at risk.

If utilities are required to install carbon capture on the existing baseload dispatchable fleet, **the capacity of the fleet will be reduced by 25% to 30% parasitic load**. This reduces the net plant output by that amount and is a huge increase in net heat rate, which means the efficiency is much lower. In this resource constrained grid, the resources to power the carbon capture systems are not available. The carbon capture system needs to run full-time when the plant is operating, which is not possible with renewable resources that are dependent on favorable weather conditions. The 18% parasitic load referenced by the EPA on page 8 of the Resource Adequacy Technical Support Document[9] is not accurate. Front-end engineering design (FEED) studies that

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4 https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts

5 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pd

6 Forecasting Resource Adequacy in MISO Through 2035 May 23, 2023. Mike Nasi, Brent Bennett, Isaac Orr, and Mitch Rolling

7 Forecasting Resource Adequacy in Southwest Power Pool Through 2035 May 23, 2023. Mike Nasi, Brent Bennett, Isaac Orr, and Mitch Rolling

8 North Dakota Transmission Authority | North Dakota Industrial Commission. On the site, select Power Forecast Reports and then the SPP or MISO document.

9 http://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf

are in progress and complete for Minnkota Power's Project Tundra and for Rainbow Energy's Coal Creek Station conclude that an accurate range for parasitic load is 25% to 30%.

The Electric Power Research Institute (EPRI) plans to submit testimony that the status of development of this technology is years from being commercially proven and should not be required.

Many regions of the country are projected to be increasingly dependent on favorable weather conditions to support wind and solar generation to meet peak demand. MISO, which is likely to be the location of the first carbon capture systems on large generating facilities, is already identified as being at risk in the NERC reliability assessments reference above. Unless additional, firm capacity offsets the parasitic load of the carbon capture system, these regions and the RTOs and ISOs responsible for them would be further strained by that additional loss of dispatchable load.

Transmission Additions as a Possible Solution

For additional wind and solar generation to replace lost capacity from coal and natural gas units required to close under this proposal, or to offset the parasitic load of carbon capture systems (putting aside the immaturity of that technology and the unrealistic time horizon for constructing them under the proposed rule), significant amounts of new transmission capacity will be required, as these renewable resources are not often located in the area of current generating units. However, the EPA assumptions of the options that utilities have for additional generation and the transmission capacity to support them are overly simplified.

For example, the EPA's discussion related to transmission on pages 3-4 of the Resource Adequacy Technical Support Document states that their Integrated Planning Model (IPM) "addresses reliable delivery of generation resources between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system, as well as the ability to endogenously expand these links based on relative economics. <u>Within each model region, IPM assumes that adequate within-region transmission capacity exists or will be built to deliver any resources located in, or transferred to, the region."</u> [10]

Perhaps the most complete study of transmission needs to achieve high penetration of renewable generation to replace fossil generation as a result of retirements due to regulations and other factors is the U.S. Department of Energy's (DOE) National Transmission Planning Study.[11] The final report is scheduled to be released later in 2023, but the review draft provides preliminary results that will likely be sustained in the final version. DOE is working with national laboratories and stakeholders to "identify viable future grid realization pathways to a large-scale transmission system buildout that would accomplish clean energy goals," including the

[10] Environmental Protection Agency. *Resource Adequacy Analysis Technical Support Document*. May 23, 2023. p.3-4. Available at: https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf
[11] National Transmission Planning Study (draft), NTPStudy@hq.doe.gov

Administration's goal to achieve 100% carbon free electricity nationally by 2035.[12] The study focused on interregional transmission, in order to facilitate a national grid that utilizes carbon neutral sources more efficiently.

The graphics within the report provide a clear picture of the amount of transmission build that is needed to reach those decarbonization goals. A heavy concentration of new transmission capacity is needed, especially in the more populous central parts of the country. The experience of the utility sector in recent years shows that building transmission is a challenging multi-year process, and in the more populated areas, it can be nearly impossible. Ten years or longer is often required from concept to in-service, including for transmission lines within an RTO region, or even within the much smaller regions as defined by EPA's IPM model. In fact, FERC's current proposal to reform regional transmission planning envisions a 20-year long-term planning scenario.[13]

Interregional transmission, between reliability regions, states, and even the EPA's small IPM regions, adds another level of complication that experience has shown further extends these timelines. Since transmission decisions are mostly made at the state level, even developing the processes to build interregional transmission efficiently will take time. In other words, the transmission buildout is a decades-long effort once a decision has been made – and the requirements set out in the EPA's proposed rule do not afford this time. Other details on proposed timelines for CCS infrastructure are available in related comments submitted by NRECA.[14]

A recent example is the MISO Multi-Value Project (MVP), a portfolio of 17 projects in the MISO region with an estimated cost of over $5 billion. After roughly six years of discussions, evaluations, planning, and cost approvals that began in 2005, MISO officially approved the slate of MVP projects in December 2011.[15] More than five years later, 13 of the 17 MVP projects were still not in service, including many that are wholly within the EPA's IPM more limited "model regions," that are assumed to have or will have sufficient transmission capacity.[16] Four were still incomplete in the third quarter of 2019, nearly eight years after MISO approval.[17] And the highest value project of the 17, the Cardinal-Hickory Creek transmission project, is still not in service, more than 12 years after MISO approval, due to drawn out permitting processes and litigation.

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[12] Department of Energy. *Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization.* January 19, 2022. 87 FR 2769. Page 2771. Available at: https://www.govinfo.gov/content/pkg/FR-2022-01-19/pdf/2022-00883.pdf

[13] Federal Energy Regulatory Commission. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking*. RM21-17, May 4, 2022. Available at https://www.federalregister.gov/documents/2022/05/04/2022-08973/building-for-the-future-through-electric-regional-transmission-planning-and-cost-allocation-and

[14] *Analysis Of EPA's Proposed Construction Timeframes for CCS Projects. Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (Docket EPA-HQ-OAR-2023-0072)*. Daniel Walsh, August 3, 2023

[15] AESL Consulting, https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf

[16] MTEP17 report, https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

[17] MTEP19, https://cdn.misoenergy.org/2019%20MVP%20Limited%20Review%20Report443829.pdf

Another example is the TransWest Express Transmission project,[18] a high-voltage, interregional transmission line crossing three states in the Mountain West. According to TransWest Express, LLC, this project was initiated in 2005 by Arizona Public Service, with the permitting process beginning in 2007 with the filing of a right-of-way application. It was not until more than 15 years later that final federal approval for the construction of this transmission line was received. TransWest estimates that construction of the transmission line will take about three years, meaning that the earliest it would be in-service would be more than 20 years after it was first initiated.

Cost is another key consideration. The DOE's National Transmission Planning Study estimates the cost of the needed transmission and generation to be at $120 billion to $170 billion per year from now through 2050 to meet the decarbonization goals, including a decarbonized electric grid by 2035, as listed above. For MISO and the PJM Interconnection, this is estimated at over a trillion dollars for each of those two regions. Other RTOs and ISOs will also require hundreds of billions of dollars.[19] This level of expenditure is unprecedented and likely not feasible.

Additional consideration must also be given to factors that could delay the construction of transmission projects. The recent strains on the supply chain resulting from COVID-19 are continuing to impact construction schedules for transmission. Transformers of all sizes are difficult to obtain, and domestic production is very limited. Sources of materials supply for transformer steel, copper, and other parts are often in areas of the world that may not be able to reliably serve the needs of the U.S. utility sector. Finally, it cannot be presumed that generator interconnections that will utilize such additional transmission capacity will occur in the timelines that EPA assumes.

Conclusion

The EPA's proposed greenhouse gas regulations for new and existing power plants sets expectations for CO_2 reductions that are not achievable considering the present state of technology, the adverse impacts on electric grid reliability, and the timelines and massive investment required for additional electric transmission infrastructure.

About the Author

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for

[18] https://www.transwestexpress.net/about/history.shtml
https://www.transwestexpress.net/about/timeline.shtml

[19] National Transmission Planning Study (draft), NTPStudy@hq.doe.gov

included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having "all of the above" energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment G

Analysis Of EPA's Proposed Construction Timeframes for CCS Projects

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

Prepared by National Rural Electric Cooperative Association's
Mr. Daniel Walsh, Senior Power Supply & Generation Director

August 3, 2023

Executive Summary

After conducting interviews with staff at several Tier 1 Engineering, Procurement and Construction (EPC) companies in the power industry, it is the conclusion of the author that the proposed timeframes for carbon capture and storage (CCS) established by the U.S. Environmental Protection Agency (EPA) for its proposed greenhouse gas (GHG) emissions standards are significantly flawed and, at best, aspirational. Key assumptions regarding site conditions, access to CO_2 pipelines, local support for a project, and times for permit reviews have not been adequately considered, resulting in an unrealistic timeframe by the EPA. Based on discussions with EPC firms, the existing site conditions along with distance and access to CO_2 storage are critical in determining an appropriate overall project schedule.

Note that the time limits discussed in the narrative below are similar for both a natural gas combined cycle and a coal steam electric facility. While there are unique characteristics to all fossil energy sites, these types of differences are minor in terms of overall project schedule impact.

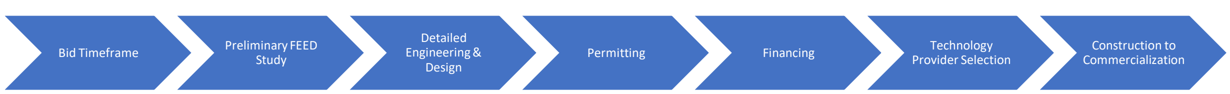
The Tier 1 EPC firms interviewed included Black & Veatch, AECOM, Burns & McDonnell, Kiewit, and Fluor.

In summary, several key assumptions have not been adequately addressed by the EPA and ignored in its review. The result is an unrealistic timeline that cannot be met by the generation industry.

Basis and Analysis

The EPA states that "Deployment of [carbon capture and storage] CCS technology involves a project schedule that can be completed in roughly five years" citing the completion of multiple phases in tandem.[1] This statement is flawed, for the following reasons.

The process from plan inception to commercialization is composed of several key phases, all of which require considerable time in order to successfully accomplish the necessary requirements.



[1] Environmental Protection Agency. *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document*. May 23, 2023. p. 36.

Bid Period:

Most companies typically require obtaining bids to satisfy procurement rules for a capital-intensive project. The time to bid, review and subsequently engage in a contract for an engineering firm is generally 6-12 months.

Preliminary FEED Study:

The amount of time to perform a front-end engineering design (FEED) study can easily exceed 12 months. In fact, most respondents indicated an 18- to 24-month time with the median at 20 months from the issuance of a purchase order. This amount depends on the complexity and size of the undertaking. In this evaluation comparison, 12 months has been selected to complete the FEED study.

A FEED study precedes a complete engineering evaluation and detailed design specification. This process takes an additional 12-24 months from the date of the purchase order. Following the FEED, the site owner must proceed with the detailed project engineering and work scope details. In this evaluation, 18 months has been used for the detailed engineering and design portion of the project.

Permitting & Financing:

As part of the complex project, the generation owner must obtain state and utility governing board approval, start permitting, and obtain financing to proceed. The financing will be contingent on receipt of Class VI permits for sequestration, selection of an EPC firm and technology provider, and receipt of all required permits, easements, land rights, etc. In addition, the financing usually requires performance guarantees from the construction firm and technology provider. Since the industry is lacking existing facilities which have demonstrated capture percentages at the EPA proposed required amount, the financing will be extremely challenging.

These steps will take between 24 and 48 months. Typically, financial institutions require all permits in hand and engineering to be at least 75% complete to reduce concerns about cost and schedule overruns in the project. The inability to receive all permits in a timely manner will negatively impact financing and construction cost and schedule.

The EPA timeline provides 52 weeks for permitting of carbon capture equipment and 104 weeks for permitting of the necessary infrastructure. This estimate provides little leeway for permitting delays, such as local opposition, which is a typical risk for any construction project, as well as opposition from national groups against these types of projects, which is to be expected for CCS projects. No additional time is provided by the EPA to satisfy this contingency. Given the current lengthy time for receiving permits, it is obvious that the EPA proposed schedule for permitting is severely understated.

With known requirements for parasitic load for capture technologies, a CCS project site owner will have to add generation to serve its load obligations, or alternatively add generation to run the CCS project. This will require more permitting and may trigger a Clean Air Act New Source

Review (NSR) requirement, causing further delays. The EPA has failed to provide a schedule time for the NSR process, which would add 24-36 months of environmental reviews and equipment procurement for new generation units, boilers, and related equipment.

Technology Provider Selection:

It is apparent that this technology has not been adequately demonstrated to achieve the levels or carbon capture amounts and sequestration that EPA proposes. Even setting aside those technical and feasibility barriers, the process to select a technology provider itself takes significant time. In our discussions with several capture technology providers, it was noted that the current backlog to start capture EPC is 12-18 months, further extending the required time. While part of this step would be performed in parallel with obtaining financing, many technology providers will require an initial significant multimillion dollar down payment, typically 20% of the overall supplied equipment cost, to begin work. This makes the timing of the start of work by the technology provider contingent on the timing of successfully obtaining financing.

The technology providers interviewed included Shell CANSOLV, MHI, Fluor, ION/Koch, Honeywell, BASF, Linde, Air Liquide, and Carbon Clean. The firms interviewed stated that the time for construction of the transport pipelines and sequestration sites will exceed the amount of time the EPA has stated for an entire project. The time to construct a facility, perform startup and acceptance testing, and start commercial operation is an additional 60-72 months.

Total Actual Timeline:

Based on the information and research obtained, an accurate time for the construction of a project is more **in the range of 10-12 years after inception**. This is evidenced by the proposed CCS sites that are currently being evaluated in the U.S., like Project Tundra by Minnkota Power Cooperative.

Potential for Variables to Extend the Timeline

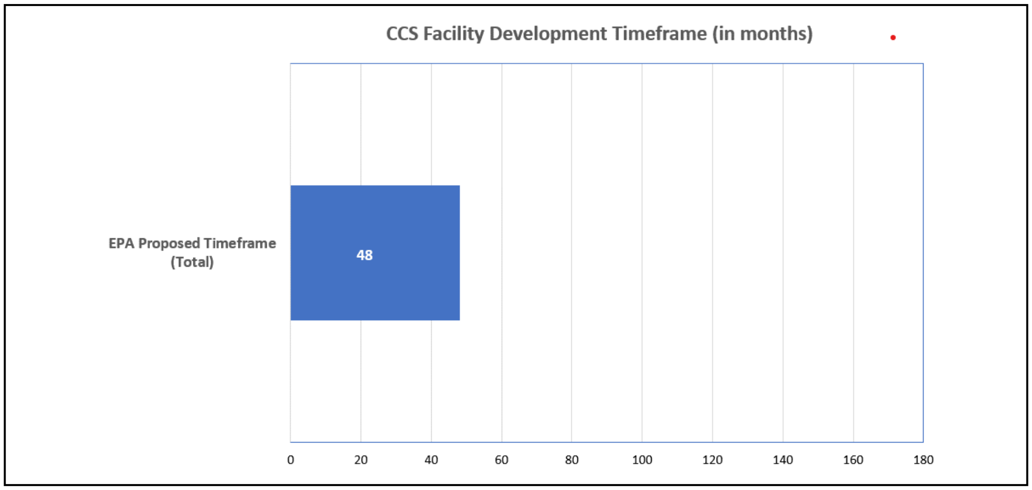
The EPA has failed to address the resource adequacy challenges that will occur when fossil generation sites accept a 25%-30% parasitic load loss to run an associated CCS site. Alternatively, if the generation owner selects to add onsite generation to run the CCS plant, then NSR and additional air permitting requirements that are federal, state, and local based may add an additional 24-36 months prior to commencing construction.

The EPA is currently “targeting” 24 months for permit approvals, following a completeness determination; however, this assumes no deficiencies. This timing is impossible, given inadequate agency resources for permit reviews, an overwhelming reluctance by the agency to support the continued use of fossil generation, and likely intense opposition to permits associated with CCS. Individual EPA regions continue to have limited capacity and lack core expertise to effectively review permit applications in support of a construction time limit required to meet the EPA proposed regulations.

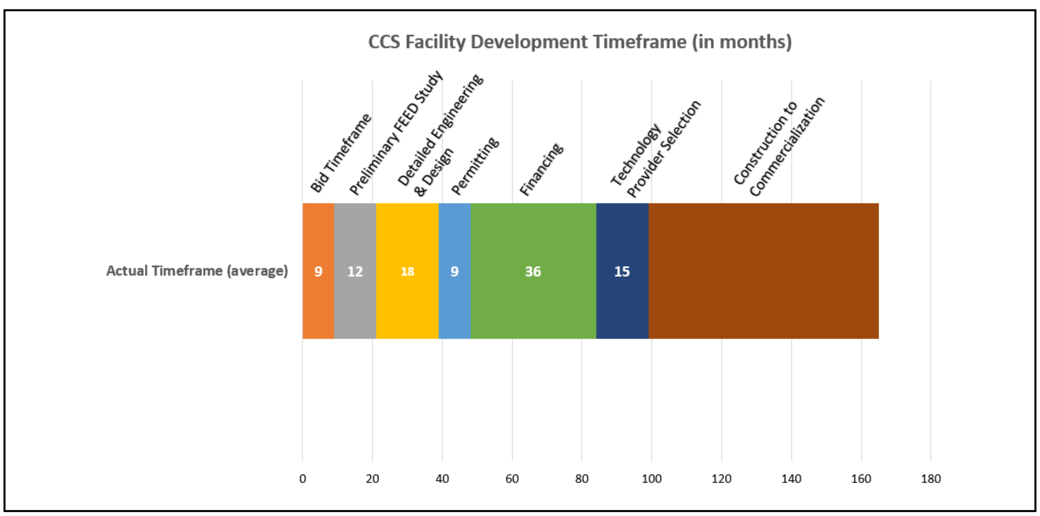
There are also many variables that can influence the exact scope and schedule for acquiring a Class VI underground injection well permit, adding to the already lengthy schedule for design and construction of the upstream carbon capture system. The Class VI well design, permitting and construction process is often longer than that of the carbon capture system. This changes the critical path of a project and pushes commercial operation dates to after the required EPA compliance dates.

EPA Proposed Timeline vs. Actual Timeline

Currently, the EPA believes that the time and schedule for the engineering, construction, and commercial operation of a fully-integrated CCS site can be done in approximately **48 months.**



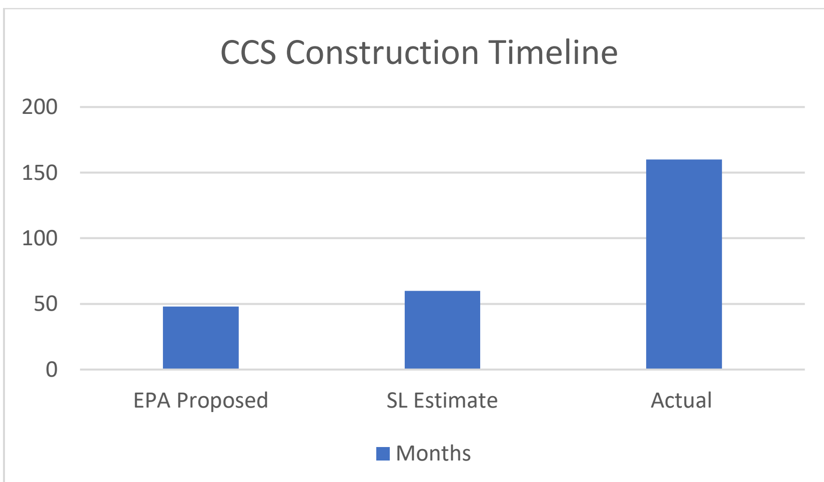
The minimum time for developing and constructing necessary CCS infrastructure, including capture facility, transport pipelines and Class VI well permitting and storage, looks more like **120 to 160 months**, as shown here.



Conclusions

The EPA has not sufficiently considered the relevant factors affecting carbon capture development and is using incorrect assumptions in determining the times required to meet the proposed compliance dates. The assumptions the EPA makes do not adequately address the times required for carbon capture, transportation, or sequestration into an approved permitted site.

The EPA used a high-level Sargent & Lundy (S&L) construction schedule, which showed several key assumptions regarding permits, land rights, water allocation, and sequestration near the CCS project. This S&L schedule clearly stated that the **best-case, high-level schedule would allow construction completion in approximately 60 months and require even more time for these critical assumptions currently absent from the analysis**. Without justification based in facts about the plant development process, the EPA arbitrarily shortened the S&L schedule, leaving an unrealistic and impossible requirement in the EPA proposed rule.



The EPA provides no engineering justification, evaluations, or facts to support a contraction in schedule, other than the belief that federal funding through stimulus and tax credits would somehow reduce the schedule.

It is a flawed assumption that funding from the Inflation Reduction Act will somehow create an environment for streamlined construction of these massive engineering projects. There are many other fundamental factors required for building the suggested large-scale facilities that are simply not in place nor feasible within the timeframe the EPA proposes. This clearly demonstrates the EPA's lack of knowledge and recognition for all the essential steps needed to construct, startup and drive a project to commercial operation.

Additionally, the required infrastructure to support carbon capture from fossil generation is not adequately detailed by the EPA, nor considered correctly. It is unrealistic to assume all generation facilities will obtain or immediately have access to sequestration sites and pipelines that are not in existence as of the date of the EPA proposed rule. Current day infrastructure simply cannot support the proposed magnitude and time of the required new technology. The EPA's proposed rule uses unrealistic assumptions within its own analysis and relies on FEED studies as examples for why a technology, which has not been built at the scale required, should be considered the best system of emissions reduction.

In summary, the EPA's proposed guidelines are based on insufficient analysis and flawed assumptions that result in a timeline that is not realistic, do not recognize the many essential steps to plant development, and will subject the industry to impossible requirements. Put simply, it is highly unlikely – indeed impossible – for any coal-fired power plant that has not already started the process of designing and constructing a CCS system even before the EPA proposed rule was published, to install CCS by 2030. It is highly unlikely for an existing combustion turbine subject to the EPA proposed rule to install CCS by January 1, 2035.

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About the Author

Mr. Daniel Walsh, NRECA Senior Power Supply & Generation Director

Daniel Walsh is the Senior Director for Generation Research and Development at the National Rural Electric Cooperative Association (NRECA), which represents the interests of over 1,000 not-for-profit electric cooperatives in the United States. In this role, he leads the Generation team overseeing a broad research portfolio including carbon capture use and storage, nuclear, existing fossil fleet, and advanced power cycles. Under his leadership, the Generation team provides technical expertise, technology assessments, and industry connections to assist NRECA members in meeting the future energy generation challenges.

Mr. Walsh joined NRECA in 2014 and brings over 35 years of experience in the energy sector. Prior to his work at NRECA, Dan held a variety of roles working in gas, steam turbine and generator engineering groups, and as manager of several combined cycle and coal fired sites.

Over his career Mr. Walsh demonstrated in-depth technical, operational knowledge and effective leadership as he advanced from roles of Plant Manager to Senior Vice President. He managed ten power generation sites, where he had responsibilities for profit and loss, environmental, health and safety, operations and maintenance, engineering and construction, and personnel management for more than 1,000 staff.

Mr. Walsh holds a bachelor's degree in mechanical engineering from the University of Connecticut. He has several external leadership roles on advisory boards for EPRI Generation, NuScale Small Module Reactors, ESIG, CEATI and serves on the steering committee for the Carbon Utilization Research Council. Prior to his energy industry career, Dan was in the U.S. Navy where he served onboard a ballistic missile submarine for five deployments. He currently resides in Florida and meets with NRECA electric cooperative members around the U.S.

Attachment H

Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. Doug Campbell, FTB Energy Solutions, Inc.

August 3, 2023

Introduction

This paper provides commentary on the Environmental Protection Agency's (EPA's) proposed rule "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule." The proposed rule would require some fossil fuel-fired stationary combustion turbine electric generating units (EGUs) to use emission control measures that are based on highly efficient generating practices, hydrogen co-firing, and carbon capture and storage.[1]

In reviewing the EPA documents for this proposed rule, it is evident that they are dependent on cost projections provided by the National Energy Technology Laboratory (NETL). The EPA cites NETL's 2022 "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity"[2] in its discussion of carbon capture for coal-fired steam EGUs and natural gas combustion turbines as being "adequately demonstrated." Regarding capture costs at existing coal-fired units, the EPA states that it has "relied heavily" on NETL information, particularly that 2022 Cost and Performance Baseline.

NETL's cost estimates are developed utilizing its Quality Guidelines for Energy System Studies (QGESS) [3] methodology and reports, notably QGESS for Carbon Dioxide Transport and Storage Costs (2019). [4] NETL estimates work very well when used to compare one technology to another. These quality guidelines are published and publicly available. As is explained in the following pages, these estimates are not complete enough to be presented as full project costs. The EPA needs to consider a more inclusive estimate, such as that presented by the EIA in its paper "Capital Cost and Performance Characteristics for Utility Scale Electric Generating Units." [5]

My focus in this analysis is addressing the difference in a NETL estimate and that of a full project cost that an owner would need to consider when presenting a project for approval to either its Board of Directors or Regulatory Authority. To demonstrate the difference, I look in detail at a NETL cost profile as compared to an engineering firm's full cost estimate prepared for the U.S. Energy Information Administration (EIA). [5] An attempt is made to provide some important definitions for the reader to understand the terms used. Also, specific differences in the scope of work are identified.

It is important to capture full project cost at the time of project initiation to obtain financing. The accuracy and detail of the estimate must be at least a Class 2 or Class 1 for project acceptance. The work presented by both NETL and Sargeant & Lundy in their full project cost estimates are Class 5 estimates and would not meet the standard required by the financial community. Lenders also look to both the technical maturity of the technology being offered and its application in similar projects to judge risk. An assessment is made of both duration and quality of performance guarantees, and proposed penalties for not meeting them. Since the life of these projects is generally 20 years or more, matching contractual terms such as rates of depreciation and power purchase agreements (PPAs) are required for all aspects of the projects.

In summary:

The NETL methodology is incomplete in determining full project costs for carbon capture and storage (CCS) projects. As outlined below, it is shown that this methodology does not include key project parameters which are required for the level of detail necessary to procure project financing. These items include fully-evaluated electrical, water, sewer, and natural gas connections. Also missing are performance wrap guarantees and sufficient owner and contractor contingency, as well as other line items identified in the report. In using the NETL methodology, the EPA has not provided a complete line by line cost analysis for CCS projects.

Executive Summary

The analysis presented below demonstrates the variance of costs that can be seen in different methodologies and scope definitions. Also included are the expected accuracy of the NETL estimates. It is then suggested that some consideration of sensitivity analysis, using both the high and low range of estimates, should be provided in the modelling. A clear definition of scope is important for decision makers to interpret results. It is concluded that, although the NETL estimating methodology is clearly defined and a good tool for comparing one technology solution to another, it is not complete enough in scope to capture full project costs. The EIA approach as demonstrated in the Sargeant & Lundy example is a better method to capture the cost of delivering these projects.

Analysis and Consideration

The following is a summary of the NETL Cost Estimation Guidelines, comparing it with an alternative pricing methodology used by the EIA to determine a similar project price, as provided in a report authored by Sargent & Lundy (February 2020). [5]

It is important to note that reference is made to Total Overnight Cost (TOC) of capital, which can be defined in different ways. One such definition of "overnight cost of capital" is provided here for reference, from the University of Calgary[6]:

> "When comparing the cost of building different types of electrical plants, firms will use various methods. For quick comparisons, firms will look at what the cost of building a plant overnight would be or the overnight cost of capital.[1] This is a hypothetical scenario because a plant cannot be constructed in one night, but it evaluates the cost of a plant if it were built right away, with current prices. This is used as a quick reference for the cost of a plant, because it does not consider the time it would take and how prices rise over time. The calculation is made without the interest rate, which would account for the rise in cost over time. The overnight cost is a very simple way to compare the cost of different plants.
>
> Some of the costs that go into the determination of the overnight are:
>
> - **Construction costs:** Installation of utilities for the plant, structural steel and other materials for the building, site planning etc.

- **Mechanical equipment supply and installation:** large pieces of machinery such as, boilers, cooling towers, steam turbines, condensers, photovoltaic modules, generators etc.
- **Electrical controls:** Equipment used to transform and transmit the electricity that is generated. Electrical transformers, switchyards, distributed control systems etc.
- **Project costs:** Costs that are incurred while the plant is being designed. Engineering costs, labor, scaffolding costs, construction management etc." [6]

It is noted that the NETL cost estimates do not always follow the definition above. As an example, NETL excludes electrical costs that are associated with the switchyard that by their definition are considered outside the fence. This is explained in more detail below.

Other cost definitions that are important to understand and are found on page 9 of NETL's 2021 QGESS for NETL Assessments of Power Plant Performance [3] are:

- **Total Plant Cost (TPC):** This is defined in the guidelines as Engineering, Procurement, Construction, and Commissioning (EPCC) cost plus project and process contingencies. In the document, NETL states that they use Engineering, Procurements, and Construction Management (EPCM) contracting costs as their base cost. This implies more risk to the owners, as the engineering firm is providing management services to the owner and the contracts remain with the owner. In the EPCC arrangement, the owner relinquishes control to the engineering firm, who then owns the contracts.
- **Total As-Spent Capital (TASC):** This comprises the sum of all capital expenditures as they incur during the capital expenditure period, including interest during construction. TASC is expressed in mixed current-year dollars over the construction and start up period to commercial operation. NETL assumes five years for coal plants and three years for gas plants.

These costs are outlined in the 2022 NETL "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" document. [2] For example, page 16 provides an example of the cost of a state-of-the-art F Class natural gas combined cycle (NGCC) built in 2017. The NETL TOC in 2018$ is 952 $/kw. The NETL TASC in 2018$, however, is $1040/kw, 9.2% more in capital costs. This demonstrates the effect of including interest during construction in the estimate. The TASC are what the owner will pay.

Cost Estimate Classification

Most engineering and economic studies completed by NETL are cost estimates intended for the purpose of early project development deliverables only. These are often limited to use in feasibility studies/conceptual planning or concept screening, classified respectively as "Class 5" and "Class 4" estimate classes by the Association for the Advancement of Cost Engineering (AACE). The classification depends on numerous factors including the maturity of the technologies under evaluation, recent commercial experience, and nature of available cost data.

NETL class estimates related to pulverized coal (PC) power plants and NGCC power plants without carbon capture are AACE Class 4. All other cost estimates related to carbon capture and hydrogen are AACE Class 5. These are the estimates the EPA references. There is a concern that, with the current upsets on the supply side and shortage of skilled labor resulting from COVID 19, all the estimates would now be in the Class 5 category. The chart below is found on page 11 of NETL's 2021 Quality Guidelines for Energy Systems. [3]

Exhibit 2-2. Features of an AACE Class 4 and Class 5 cost estimates

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	• Plant capacity, block schematics, indicated layout, process flow diagrams for main process • Systems and preliminary engineered process and utility • Equipment lists	**Class 4** -15% to +30%
0 to 2%	• Cost estimates (i.e., feasibility study) based on the level of engineering design performed • This range is deemed reflective of recent commercial power IGCC experience	**Class 5** -25% to +50%

For a project to proceed, at minimum, a Class 2 estimate would be recommended that would have a more limited spread of -5% to +20% expected accuracy. More likely, to receive financing, a Class 1 estimate of -3% to +15% would be required. Explanation of this classification matrix is provided in AACE "Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Process Industries." [7]

Capital Cost Contingencies

A process contingency is used to account for uncertainty within a project by adding in an amount of costs for unaccounted for or unforeseen events. An example would be during an excavation where bedrock is below expected levels, so additional fill needs to be removed. It is not clear in the NETL guidelines exactly what would be included for process contingency. On page 12 of the NETL guideline,[3] it states "Process contingency is typically not applied to costs that are set equal to research goal or programmatic target, since these values are generally intended to reflect the total cost."

Later in the same page, it states, "AACE International Recommended Practice No. 16R-90 "Conducting Technical and Economic Evaluations – As applied for the Process and Utility Industries,"(AACE 16R-90)" says that project contingency for a "budget-type" estimate (AACE Class 4 or 5) should be 15 to 30 percent of the sum of Bare Erected Costs (BEC); Engineering, Procurement, and Construction fees (EPC fees); and process contingency." [7] NETL then states that the owner's cost could be as high as 20% on top of the sum. In its Exhibit 2-4 on page 13, NETL further clarifies that it uses 15% of the Total Project Costs (TPC) as owner's contingency. This is based on information from a rule-of-thumb estimate from a 2019 professional conversation with Black & Vetch on the topic. The use of these different percentages is confusing and addressed in the conclusions of this report.

Costs Not included by NETL Estimates

As with the capital cost contingencies estimates, it is important to note what is not included in NETL estimates related to owner's costs. They particularly stated on page 14 [3]:

"This lumped cost does not include:

- EPC risk premiums (costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost).
- Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar.
- Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes.
- Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations."

Other Costs

NETL details in the 2021 Quality Guidelines for Energy System Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance [3] that there are other key cost considerations that are not included in power plant cost estimation methodology. Notably, NETL uses a "fence line" reference description to determine the cost structure, terminating at the high voltage side of the main power transformer. This omits many items that would be normal costs for a typical project and need to be included, but that are unique to site conditions and interconnect requirements. Page 14 of NETL's guidelines details specifically:

> "Some typical examples of items outside the fence line include new access roads and railroad tracks; Upgrades to existing roads to accommodate increased traffic; Makeup water pipe outside the "fence line"; Landfill for on-site waste (slag) disposal; Natural gas line for back up fuel provisions; Plant switchyard; and Electrical transmission lines and substation."
>
> "All estimates are based on a reasonably standard plant. No unusual or extraordinary process equipment is included such as: Excessive water treatment equipment; Air-cooled condensers; Automatic coal reclamation."

> "Other items that are not addressed in the cost estimates are: Piles or caissons; Rock removal; Excessive dewatering; Expansive soil considerations; Excessive seismic considerations; Extreme temperature considerations; Hazardous or contaminated soils; Demolition or relocation of existing structures; Leasing of offsite land for parking or laydown; Busing of craft to site; Costs of offsite storage."

NETL comments "to the extent that these items are needed at specific sites, they should be explicitly included within the capital cost structure, rather than part of the contingency costs."

Experience would show most of the noted expenses would occur on any site in one form or another. If a Class 2 cost estimate were used, it would be expected that these items would not exceed the upper limit of 20% of the cost. A less detailed estimate, such as Class 5 or Class 4 estimates, could make a project more exposed to risk. An example would be estimating civil works, such as excavation and piles. A Class 5 estimate would not have detailed engineering completed at a level to fully define the civil works. In doing a Class 1 or Class 2 estimate, bore holes and soil samples would have been carried out to define the conditions for foundations.

EIA Estimates using Sargent & Lundy Capital Cost Study

To accurately reflect the changing costs for new electric power generators for EIA's Annual Energy Outlook 2020 report, EIA commissioned Sargent & Lundy to evaluate the capital cost and performance for 25 electric generating types. The following sections discuss the findings of this report for the case of a 650 MW unit with 90% capture as displayed in Appendix 2.

Methodology

Sargent & Lundy used a top-down capital cost estimate using both publicly available and internal sources to establish its cost parameters. It is an overnight capital cost estimate. The following is extracted from their report: "Capital Cost and Performance for Utility Scale Electric Generating Units" pages viii and ix [5]:

> "The capital cost estimates represent a complete power plant facility on a generic site at a non-specific U.S. location. As applicable, the basis of the capital costs is defined as all costs to engineer, procure, construct, and commission all equipment within the plant facility fence line. As described in the following section, we have also estimated location adjustments to help establish the cost impacts to project implementation in more specific areas or regions within the United States. Capital costs account for all costs incurred during construction of the power plant before the commercial online date. The capital costs are divided between engineering, procurement, and construction (EPC) contractor and owner's costs. Sargent & Lundy assumes that the power plant developer or owner will hire an EPC contractor for turnkey construction of the project. Unless noted otherwise, the estimates assume that the EPC contractor cost will include procurement of equipment, materials, and all construction labor associated with the project. The capital costs provided are overnight capital costs in 2019 price levels. Overnight capital costs represent the total cost a developer would expect to incur during the construction of a

project, excluding financing costs. The capital cost breakdowns for the EPC contractor are as follows:

- The civil and structural material and installation cost includes all material and associated labor for civil and structural tasks. This includes both labor and material for site preparation, foundation, piling, structural steel, and buildings.
- The mechanical equipment supply and installation cost includes all mechanical equipment and associated labor for mechanical tasks. This includes both labor and material for equipment installation such as pumps and tanks, piping, valves, and piping specialties.
- The electrical and instrumentation and controls supply, and installation includes all costs for transformers, switchgear, control systems, wiring, instrumentation, and raceway.
- The project indirect costs include engineering, construction management, and start-up and commissioning. The fees include contractor overhead costs, fees, and profit.

The owner's costs primarily consist of costs incurred to develop the project as well as land and utility interconnection costs. The owner's development costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Outside-the-fence-line costs are considered as owner's costs. These include electrical interconnection costs and natural gas interconnection and metering costs; however, these costs too are generic and based on nominal distances to substations and gas pipeline laterals. We have also assumed that no substation upgrades would be required for the electrical interconnection. Transmission costs are based on a one-mile transmission line (unless otherwise stated) with voltage ranging from 230 kilovolts (kV) to 500 kV depending on the unit capacity. Land requirements are based on typical land requirements for each technology with per-acreage costs based on a survey of typical site costs across the United States.

The overall project contingency is also included to account for undefined project scope and pricing uncertainty for both capital cost components and owner's cost components. The levels of contingency differ in some of the estimates based on the nature of the technology and the complexity of the technology implementation."

Comparison of Capital Cost Estimates by Sargent & Lundy Estimate and NETL Estimate

The NETL study uses case B128.90 on page 505 of their publication, "Cost and Performance Baseline Fossil Energy Plant Volume 1" [2] and included in Appendix 1. The Sargent & Lundy Case is from the EIA document, "Capital Cost and Performance Characteristics for Utility Scale Electric Generating Units," which is Case 3 on page 3-6 of the document [5] and included in Appendix 2.

The cost comparisons used and as discussed above were for a 650 MW Net Ultra – Supercritical Unit with 90% capture. These are similarly designed units, however cost estimated in two different ways. The NETL estimate is a Class 5 estimate based on NETL guidelines discussed above. The Sargent & Lundy estimate is described as a generic location EPC estimate, but does not provide an AACE classification.

As explained in the Sargent & Lundy narrative above and as shown in Appendix 2, they developed a total overnight cost for an EPC contractor. This is fundamentally different than the NETL estimate, in that it includes project contingency values appropriate to offset risk that the contractor assumes when signing an EPC contract. The NETL estimate assumes an EPCM contact where the owner retains the risk. When looking at the contingency numbers, NETL include $368,875, while Sargent & Lundy estimate a contingency of $498,157. This could be a confirmation by Sargent & Lundy of the additional risk associated with EPCM that would apply to owner's cost. Also noted, the Sargent & Lundy estimate specifically identifies an owner's cost, but it is not identified as a line item in the NETL estimate.

Upon reviewing Appendix 2, the reader can see that many of the items listed on page 6 of this report as "items outside the fence line but normal cost additions for a project" are included in the Sargent & Lundy work. These are not included in the NETL estimate. Listed are costs for interconnection, both electrical and pipelines that are not in the NETL estimate.

Interest incurred during construction (IDC) is included in NETL's costs. For a coal unit it would be over 5 years. The Sargent & Lundy estimate uses an overnight cost, which does not include this financing. The concern is that including the interest in the NETL costs reduces the capital available for the project. Since every utility generally has its own cost of capital, it would be difficult to determine the appropriate costs using that method.

Results

In the previous comparisons, we have pointed out key components of the two methodologies used to determine project costs. The NETL method, although consistent and true to its guidelines, leaves out some major components of project costs. The assumption of EPCM contracting also puts risk on the owner for any overruns that might occur.

The result of this analysis for a 90% capture an ultra-super critical (USC) coal unit is two significantly different cost estimates. The NETL estimate is $3482/kw, while the Sargent & Lundy estimate is $5876/kw. This difference of 168% exceeds the high side of a Class 5 estimate. Examination of the details of the two estimates in the Appendix clearly shows that the addition to the scope required to make a full project cost is the difference.

Conclusion

The results of the review show that a full cost estimate provided by the Sargent & Lundy work can be substantially higher than an estimate that is provided by the NETL guidelines. While NETL costs estimates and methodologies are used to compare one technology option to another and do this consistently and fairly, a unit owner is exposed to full project costs and risks not fully captured by these NETL assumptions. Notably, capital cost contingencies, owner's costs, and outside the fence line costs that are necessary parts of a project are not fully accounted. When evaluating the cost of capital for major infrastructure projects, such as carbon capture systems, a more complete "all-in cost" estimate would be more appropriate.

An example of an area of concern would be using a contingency of 16.4 % of Total Project Cost, which includes Process and Total Project Contingency, as seen in Appendix 1 below. This seems to be a low estimate, especially given the NETL assumption: "All estimates are based on reasonable standard plant design. No unusual or extraordinary process equipment is included," as stated on page 14 of the reference document. [3] The AACE guidelines "Conducting Technical and Economic Evaluation as Applied to Process and Utility Industry" [7] identifies that contingency could be between 15% to 30%.

It is important that full project costs be captured and understood to reduce the owner's risk prior to acquiring financing. The EIA estimate as provided by Sargent & Lundy shows a more complete accounting of project costs. Unfortunately, this is only a Class 5 estimate. In order to obtain financing or regulatory approval, the project owner must obtain a Class 2 estimate, and, in today's climate, a Class 1 or better estimate would be required.

Listed below are the main findings from this review and expressed concerns on how the NETL methodology is applied.

- The NETL Methodology is incomplete in determining full project costs for CCS projects. As outlined within this document, it is shown that methodology does not include key project parameters which are required for the detail necessary to procure project financing. These items include fully evaluated electrical, water, sewer, and natural gas connections. Also missing are performance wrap guarantees, and sufficient owner and contractor contingency, as well as other line items identified in the report.
- In using the NETL methodology, which works well only as a price comparison for different types of technology, the EPA has not provided a complete line by line cost analysis for CCS projects.
- Because the EPA used the NETL methodology, the EPA has not identified the full project cost as seen by the owner. An example of this is demonstrated above in the capital cost comparison. Here, the NETL methodology does not identify a clear overnight cost. Each entity will determine its own cost of treating interest during construction, according to the project schedule. This would then be presented as the project cost.

When running the IPM model, specific attention should be given to the accuracy of AACE Class 4 and Class 5 estimates. It is recommended that sensitivity analysis should be carried out for the high and low side of both the NETL and Sargent & Lundy estimates, using AACE Class 5 ranges. This would provide a better assessment of risk associated with the various technical options available.

References

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About the Author

Mr. Doug Campbell, FTB Energy Solutions, Inc.

Mr. Doug Campbell is a professional engineer with demonstrated managerial ability including planning, financial control, contract management, staff supervision and reporting. Over a 48-year career, Mr. Campbell has developed a wide range of technical skills associated with the design construction and start-up of new generation and the operation and maintenance of existing generation facilities. He has held positions as Manager of Hydro, Manager of a Multi-unit Steam Plant and Combustion Turbine operation, as well as Director of Generation Services in a vertically-integrated utility. As a Senior Technical Advisor, Mr. Campbell contributed to various engineering problems, such as recent studies on inspection and evaluation of fitness for service for high pressure equipment and various pressure retaining component parts. His involvement as an independent contractor has been in providing expert advice on new and developing technologies to support the transformation of the electrical grid. Current work includes providing insights in these developments, especially as related to a low carbon world. Mr. Campbell completed a Master of Science in Energy from Heriot-Watt University in 2018 and a Master of Applied Economics from Saint Mary's University in 2022, which has allowed him to obtain additional skills to evaluate technology and to comment on the strategic outcomes of their application.

Appendix 1: NETL Estimate

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-89. Case B12B.90 total plant cost details

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,174	$0	$529	$0	$1,702	$298	$0	$300	$2,300	$4
1.2	Coal Stackout & Reclaim	$3,853	$0	$861	$0	$4,714	$825	$0	$830	$6,369	$10
1.3	Coal Conveyors	$35,499	$0	$8,443	$0	$43,943	$7,690	$0	$7,745	$59,377	$91
1.4	Other Coal Handling	$4,932	$0	$1,037	$0	$5,969	$1,045	$0	$1,052	$8,066	$12
1.5	Sorbent Receive & Unload	$225	$0	$67	$0	$293	$51	$0	$52	$396	$1
1.6	Sorbent Stackout & Reclaim	$1,650	$0	$298	$0	$1,949	$341	$0	$343	$2,633	$4
1.7	Sorbent Conveyors	$2,500	$544	$605	$0	$3,649	$639	$0	$643	$4,931	$8
1.8	Other Sorbent Handling	$120	$28	$62	$0	$211	$37	$0	$37	$285	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,630	$2,148	$0	$3,778	$661	$0	$666	$5,105	$8
	Subtotal	**$49,954**	**$2,202**	**$14,051**	**$0**	**$66,207**	**$11,586**	**$0**	**$11,669**	**$89,462**	**$138**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,522	$0	$484	$0	$3,006	$526	$0	$530	$4,062	$6
2.2	Prepared Coal Storage & Feed	$8,488	$0	$1,828	$0	$10,315	$1,805	$0	$1,818	$13,938	$21
2.5	Sorbent Preparation Equipment	$1,110	$48	$227	$0	$1,386	$242	$0	$244	$1,872	$3
2.6	Sorbent Storage & Feed	$1,861	$0	$702	$0	$2,563	$449	$0	$452	$3,463	$5
2.9	Coal & Sorbent Feed Foundation	$0	$737	$646	$0	$1,383	$242	$0	$244	$1,869	$3
	Subtotal	**$13,981**	**$785**	**$3,887**	**$0**	**$18,653**	**$3,264**	**$0**	**$3,288**	**$25,205**	**$39**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$3,973	$6,811	$3,406	$0	$14,190	$2,483	$0	$2,501	$19,175	$29
3.2	Water Makeup & Pretreating	$7,880	$788	$4,465	$0	$13,133	$2,298	$0	$3,086	$18,517	$28
3.3	Other Feedwater Subsystems	$3,101	$1,017	$966	$0	$5,084	$890	$0	$896	$6,870	$11
3.4	Service Water Systems	$2,489	$4,751	$15,384	$0	$22,623	$3,959	$0	$5,316	$31,898	$49
3.5	Other Boiler Plant Systems	$767	$279	$698	$0	$1,744	$305	$0	$307	$2,357	$4
3.6	Natural Gas Pipeline and Start-Up System	$3,341	$144	$108	$0	$3,592	$629	$0	$633	$4,854	$7
3.7	Waste Water Treatment Equipment	$12,932	$0	$7,926	$0	$20,858	$3,650	$0	$4,902	$29,409	$45
3.8	Spray Dryer Evaporator	$16,923	$0	$9,798	$0	$26,721	$4,676	$0	$6,280	$37,677	$58
3.9	Miscellaneous Plant Equipment	$225	$30	$115	$0	$370	$65	$0	$87	$521	$1
	Subtotal	**$51,632**	**$13,819**	**$42,864**	**$0**	**$108,315**	**$18,955**	**$0**	**$24,008**	**$151,278**	**$233**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$268,021	$0	$152,717	$0	$420,738	$73,629	$0	$74,155	$568,522	$874
4.10	Selective Catalytic Reduction System	$30,239	$0	$17,267	$0	$47,506	$8,314	$0	$8,373	$64,193	$99
4.11	Boiler Balance of Plant	$1,763	$0	$1,005	$0	$2,768	$484	$0	$488	$3,740	$6
4.12	Primary Air System	$1,692	$0	$964	$0	$2,657	$465	$0	$468	$3,590	$6
4.13	Secondary Air System	$2,563	$0	$1,461	$0	$4,024	$704	$0	$709	$5,437	$8

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
4.14	Induced Draft Fans	$5,530	$0	$3,151	$0	$8,680	$1,519	$0	$1,530	$11,729	$18
4.15	Major Component Rigging	$93	$0	$53	$0	$146	$25	$0	$26	$197	$0
4.16	Boiler Foundations	$0	$398	$350	$0	$748	$131	$0	$132	$1,011	$2
	Subtotal	**$309,901**	**$398**	**$176,967**	**$0**	**$487,267**	**$85,272**	**$0**	**$85,881**	**$658,420**	**$1,012**
	5					**Flue Gas Cleanup**					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$141,501	$62,150	$130,515	$0	$334,167	$58,479	$56,808	$78,654	$528,109	$812
5.2	WFGD Absorber Vessels & Accessories	$79,280	$0	$16,957	$0	$96,237	$16,841	$0	$16,962	$130,040	$200
5.3	Other FGD	$1,263	$0	$972	$0	$2,235	$391	$0	$394	$3,021	$5
5.4	Carbon Dioxide (CO_2) Compression & Drying	$42,506	$6,376	$14,212	$0	$63,093	$11,041	$0	$14,827	$88,962	$137
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$467	$74	$200	$0	$741	$130	$0	$174	$1,045	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,661	$585	$2,617	$0	$5,863	$1,026	$0	$1,033	$7,923	$12
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$197	$173	$0	$370	$65	$0	$65	$500	$1
5.13	Gypsum Dewatering System	$762	$0	$128	$0	$890	$156	$0	$157	$1,203	$2
	Subtotal	**$268,440**	**$69,383**	**$165,774**	**$0**	**$503,597**	**$88,129**	**$56,808**	**$112,267**	**$760,802**	**$1,170**
	7					**Ductwork & Stack**					
7.3	Ductwork	$0	$746	$518	$0	$1,264	$221	$0	$223	$1,708	$3
7.4	Stack	$8,814	$0	$5,122	$0	$13,936	$2,439	$0	$2,456	$18,831	$29
7.5	Duct & Stack Foundations	$0	$210	$249	$0	$459	$80	$0	$108	$647	$1
	Subtotal	**$8,814**	**$956**	**$5,889**	**$0**	**$15,659**	**$2,740**	**$0**	**$2,787**	**$21,186**	**$33**
	8					**Steam Turbine & Accessories**					
8.1	Steam Turbine Generator & Accessories	$72,900	$0	$8,124	$0	$81,024	$14,179	$0	$14,280	$109,484	$168
8.2	Steam Turbine Plant Auxiliaries	$1,654	$0	$3,522	$0	$5,176	$906	$0	$912	$6,994	$11
8.3	Condenser & Auxiliaries	$11,146	$0	$3,782	$0	$14,928	$2,612	$0	$2,631	$20,172	$31
8.4	Steam Piping	$43,007	$0	$17,430	$0	$60,437	$10,576	$0	$10,652	$81,666	$126
8.5	Turbine Generator Foundations	$0	$258	$427	$0	$685	$120	$0	$161	$966	$1
	Subtotal	**$128,707**	**$258**	**$33,285**	**$0**	**$162,251**	**$28,394**	**$0**	**$28,637**	**$219,281**	**$337**
	9					**Cooling Water System**					
9.1	Cooling Towers	$19,149	$0	$5,922	$0	$25,072	$4,388	$0	$4,419	$33,878	$52
9.2	Circulating Water Pumps	$2,697	$0	$198	$0	$2,896	$507	$0	$510	$3,913	$6
9.3	Circulating Water System Auxiliaries	$16,029	$0	$2,115	$0	$18,143	$3,175	$0	$3,198	$24,516	$38
9.4	Circulating Water Piping	$0	$7,410	$6,710	$0	$14,120	$2,471	$0	$2,489	$19,079	$29

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
9.5	Make-up Water System	$1,241	$0	$1,594	$0	$2,834	$496	$0	$500	$3,830	$6
9.6	Component Cooling Water System	$1,155	$0	$886	$0	$2,040	$357	$0	$360	$2,757	$4
9.7	Circulating Water System Foundations	$0	$691	$1,148	$0	$1,839	$322	$0	$432	$2,593	$4
	Subtotal	**$40,271**	**$8,101**	**$18,572**	**$0**	**$66,944**	**$11,715**	**$0**	**$11,907**	**$90,566**	**$139**
	10					**Ash & Spent Sorbent Handling Systems**					
10.6	Ash Storage Silos	$1,170	$0	$3,578	$0	$4,747	$831	$0	$837	$6,415	$10
10.7	Ash Transport & Feed Equipment	$3,977	$0	$3,943	$0	$7,920	$1,386	$0	$1,396	$10,701	$16
10.9	Ash/Spent Sorbent Foundation	$0	$813	$1,001	$0	$1,814	$317	$0	$426	$2,558	$4
	Subtotal	**$5,146**	**$813**	**$8,521**	**$0**	**$14,481**	**$2,534**	**$0**	**$2,659**	**$19,674**	**$30**
	11					**Accessory Electric Plant**					
11.1	Generator Equipment	$2,658	$0	$2,005	$0	$4,663	$816	$0	$822	$6,300	$10
11.2	Station Service Equipment	$7,505	$0	$644	$0	$8,148	$1,426	$0	$1,436	$11,010	$17
11.3	Switchgear & Motor Control	$11,650	$0	$2,021	$0	$13,671	$2,392	$0	$2,410	$18,473	$28
11.4	Conduit & Cable Tray	$0	$1,514	$4,364	$0	$5,879	$1,029	$0	$1,036	$7,944	$12
11.5	Wire & Cable	$0	$4,011	$7,169	$0	$11,180	$1,956	$0	$1,970	$15,107	$23
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$823	$0	$760	$0	$1,583	$277	$0	$279	$2,139	$3
11.8	Main Power Transformers	$6,966	$0	$142	$0	$7,108	$1,244	$0	$1,253	$9,605	$15
11.9	Electrical Foundations	$0	$221	$563	$0	$784	$137	$0	$184	$1,106	$2
	Subtotal	**$29,657**	**$5,747**	**$17,859**	**$0**	**$53,262**	**$9,321**	**$0**	**$9,434**	**$72,017**	**$111**
	12					**Instrumentation & Control**					
12.1	Pulverized Coal Boiler Control Equipment	$803	$0	$143	$0	$946	$166	$0	$167	$1,278	$2
12.3	Steam Turbine Control Equipment	$719	$0	$80	$0	$799	$140	$0	$141	$1,080	$2
12.5	Signal Processing Equipment	$911	$0	$162	$0	$1,074	$188	$0	$189	$1,451	$2
12.6	Control Boards, Panels & Racks	$279	$0	$170	$0	$449	$79	$22	$82	$632	$1
12.7	Distributed Control System Equipment	$7,864	$0	$1,402	$0	$9,266	$1,622	$463	$1,703	$13,053	$20
12.8	Instrument Wiring & Tubing	$551	$441	$1,762	$0	$2,753	$482	$138	$506	$3,879	$6
12.9	Other Instrumentation & Controls Equipment	$677	$0	$1,568	$0	$2,245	$393	$112	$412	$3,162	$5
	Subtotal	**$11,803**	**$441**	**$5,288**	**$0**	**$17,531**	**$3,068**	**$736**	**$3,200**	**$24,535**	**$38**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$462	$9,804	$0	$10,266	$1,797	$0	$2,412	$14,475	$22
13.2	Site Improvements	$0	$2,283	$3,017	$0	$5,300	$928	$0	$1,246	$7,474	$11
13.3	Site Facilities	$2,609	$0	$2,737	$0	$5,346	$935	$0	$1,256	$7,537	$12
	Subtotal	**$2,609**	**$2,745**	**$15,558**	**$0**	**$20,912**	**$3,660**	**$0**	**$4,914**	**$29,486**	**$45**
	14					**Buildings & Structures**					
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$184	$146	$0	$330	$58	$0	$58	$446	$1
14.6	Water Treatment Buildings	$0	$460	$419	$0	$880	$154	$0	$155	$1,189	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1
14.10	Waste Treating Building & Structures	$0	$642	$1,945	$0	$2,587	$453	$0	$456	$3,496	$5
	Subtotal	**$0**	**$31,312**	**$29,859**	**$0**	**$61,170**	**$10,705**	**$0**	**$10,781**	**$82,657**	**$127**
	Total	**$920,915**	**$136,959**	**$538,376**	**$0**	**$1,596,250**	**$279,344**	**$57,544**	**$311,431**	**$2,244,569**	**$3,452**

Appendix 2:
EIA/Sargent & Lundy Estimate Reference EIA Cost and Performance Characteristic Estimates for Utility Scale Electric Generation Technologies

EIA – Capital Cost Estimates – 2019 $s			
Configuration		650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture 1 x 831 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	12507	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	15%	
Owner's Services	% of Project Costs	5%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		311,200,000
Mechanical – Boiler Plant	$	967,433,333	
Mechanical – Turbine Plant	$	242,533,333	
Mechanical – Balance of Plant	$	92,077,778	
Mechanical Subtotal	$		1,302,044,444
Electrical – Main Power System	$	26,350,000	
Electrical – Aux Power System	$	31,050,000	
Electrical – BOP and I&C	$	113,150,000	
Electrical – Substation and Switchyard	$	23,350,000	
Electrical Subtotal	$		193,900,000
CCS Plant Subtotal	$		663,846,000
Project Indirects	$		390,200,000
EPC Total Before Fee	$		2,861,190,000
EPC Fee	$		286,119,000
EPC Subtotal	$		3,147,309,000
Owner's Cost Components (Note 2)			
Owner's Services	$		157,365,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000

Case 3 EIA – Capital Cost Estimates – 2019 $s			
Configuration			650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture 1 x 831 MW Gross
Combustion Emissions Controls			Low NOx Burners / OFA
Post-Combustion Emissions Controls			SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%
Fuel Type			High Sulfur Bituminous
	Units		
Owner's Cost Subtotal	$		173,735,000
Project Contingency	$		498,157,000
Total Capital Cost	$		3,819,201,000
	$/kW net		5,876
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			

Attachment I

TECHNICAL COMMENTS ON HYDROGEN AND AMMONIA FIRING

REGARDING:

EPA'S PROPOSAL ENTITLED "NEW SOURCE PERFORMANCE STANDARDS FOR GHG EMISSIONS FROM NEW AND RECONSTRUCTED EGUS; EMISSION GUIDELINES FOR GHG EMISSIONS FROM EXISTING EGUS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE" (DOCKET EPA-HQ-OAR-2023-0072)

PREPARED FOR:

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

PREPARED BY:

KIEWIT ENGINEERING GROUP, INC.

AUGUST 4, 2023

TABLE OF CONTENTS

1. ANALYSIS OF EPA'S TECHNICAL SUPPORT DOCUMENT

This section of the report will discuss two of the Environmental Protection Agency's (EPA) Technical Support Documents:

- Resource Adequacy Analysis
- Hydrogen in Combustion Turbine Electric Generating Units

1.1 RESOURCE ADEQUACY ANALYSIS

The Technical Support Documents for EPA's proposed "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" ("proposed EPA CO2 Rule") are based on the Integrated Planning Model (IPM) model. They developed two cases: a post-Inflation Reduction Act (IRA) 2022 Reference case and a Proposal case, which models the impact of EPA's rule. The proposal case is summarized in table below.

EPA: CO2 Rule, Proposal Case, Resource Adequacy	2028	2030	2035	2040	2045	2050	2055
1. Reserve Margin Capacity Summer [MW]	926,851	950,216	1,016,190	1,093,695	1,182,107	1,280,223	1,359,074
Plus Firm Contract Purchases Summer [MW]	0	0	0	0	0	0	0
Plus Transmission In Summer [MW]	100,391	98,069	99,476	99,293	124,498	146,303	151,862
Less Firm Contract Sales Summer [MW]	0	0	0	0	0	0	0
Less Transmission Out Summer [MW]	96,561	93,756	93,611	92,304	118,358	141,362	147,196
Total Reserve Margin Capacity Summer [MW]	**930,682**	**954,529**	**1,022,056**	**1,100,684**	**1,188,246**	**1,285,164**	**1,363,740**
Accredited Capability (MW)	1,733,344	1,777,388	1,901,950	2,047,662	2,212,026	2,394,207	2,541,250
2. Peak Load Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Less DSM [MW]	0	0	0	0	0	0	0
Net Demand Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Peak Load Growth (%/year)		1.27%	1.38%	1.49%	1.54%	1.58%	1.20%
3. Reserve Margin Summer [%]	**15**	**15**	**15**	**15**	**15**	**15**	**15**

To expand on this information, we provide a comparison of the Proposal case (vs. Reference Case) through 2035 is shown in tables below.

The first table shows the Reference Case.

EPA: New CO2 Rule (5/11/2023), Reference Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	9,338	1,351	0	0	0	10,689	1,527
New_Gas_CCS	0	6,662	3,713	0	0	0	10,375	1,482
Retrofit Coal_CCS	0	16,000	5,064	0	0	0	21,064	3,009
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**31,999**	**10,129**	**0**	**0**	**0**	**42,128**	**6,018**
Retire_Coal	56,296	24,855	23,068	8,803	13,672	12,145	138,838	5,142
Retire_Gas	1,695	733	3,797	639	14,648	14,542	36,055	1,335
Total_Retire_CG	**57,991**	**25,588**	**26,865**	**9,442**	**28,320**	**26,687**	**174,893**	**6,478**
New_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
New_Gas_CT	13,812	0	10,222	43,528	94,760	106,386	268,707	9,952
Total_New_Gas	**47,497**	**0**	**13,389**	**43,814**	**94,876**	**109,325**	**308,901**	**11,441**
Gas ($/MMBtu)	$3.02	$2.53	$2.10	$2.19	$2.13	$1.91	$2.31	
Source: EPA, Post-IRA 2022 Reference Case, Integrated Planning Model (5/11/2023)								

The second table shows the proposal case.

EPA: New CO2 Rule (5/11/2023), Proposal Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	12,104	6	0	0	0	12,111	1,730
New_Gas_CCS	0	4,188	3,855	0	0	0	8,043	1,149
Retrofit Coal_CCS	0	16,293	3,861	0	0	0	20,154	2,879
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**32,586**	**7,722**	**0**	**0**	**0**	**40,308**	**2,118**
Retire_Coal	57,758	23,626	44,988	3,655	9,028	158	139,213	5,156
Retire_Gas	1,695	1,162	3,595	574	14,693	14,461	36,181	1,340
Total_Retire_CG	**59,454**	**24,788**	**48,584**	**4,229**	**23,721**	**14,619**	**175,394**	**6,496**
New_Gas_CC	37,193	0	686	341	727	2,439	41,386	1,533
New_Gas_CT	13,990	123	33,048	38,638	89,406	96,079	271,283	10,048
Total_New_Gas	**51,183**	**123**	**33,734**	**38,979**	**90,133**	**98,518**	**312,669**	**11,580**
Gas ($/MMbtu)	$3.02	$2.76	$2.05	$2.14	$2.12	$1.88	$2.33	
Hydrogen ($/MMbtu)	$0.00	$7.40	$3.70	$3.70	$3.70	$3.70	$3.70	
New H2-CCGT (MW)	0	233	10,382	1,997	632	7,887	**21,131**	1,057
New H2-CCGT (Tbtu)	0	3	294	347	58	80		
EPA Peak Demand	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,987**	**307,495**	**1.5%**
Source: EPA, CO2 Rule, Proposal Case, Integrated Planning Model (5/11/2023)								

Of these projected NGCC builds, 6.4 GW are to co-fire hydrogen under the Proposal case. Using the methodology outlined above, EPA estimated that in 2040, approximate 2 GW of capacity increased hydrogen co-fire blends to 96% by volume while the remaining capacity reduced dispatch to below 50% under the Proposal case.

EPA did not analyze the impacts of gas-CCS as a compliance measure within this subcategory, which is not helpful to the industry in trying to evaluate the impact to manufacturing and construction resources. It is not possible to determine how much hydrogen production will be needed without determining how many plants are expected to implement CCS instead of using hydrogen to achieve compliance.

EPA estimated that in 2040 approximately 2 GW of capacity increased hydrogen co-fire blends to 96% by volume and the remaining capacity reduced dispatch to below 50% capacity factor. About 80% of the reduction in generation were apportioned to existing NGCC units operating below 50% capacity factor and the remaining 20% apportioned to incremental non-emitting resources. The decreases in generation from affected new NGCC units are offset by increases in replacement generation.

The net result is that utilities would need to expend significant capital to comply with this rule. Since the volumes of hydrogen are likely to be limited, the ability to satisfy 96% hydrogen firing for a 300 MW plant with greater than 50% capacity factor will be challenging. Therefore, the remaining choices for compliance will be to reduce capacity factor to less than 50% or implement CCS. In the case of reducing capacity factor to less than 50%, additional generating capacity will have to be brought online to meet electricity demand or existing, less efficient generation will have to increase its output. The result is that no decrease, or even an overall increase, in emissions will occur, and a duplication or overbuilding of plants required to meet overall capacity demands will occur instead. Bottom line, the regulations will likely result in a lot of units, including a lot of new units running below 50% capacity. Thus, this modeling shows the potential flaws of EPA's rule which are likely to significantly increase costs and decrease efficiency of capital without achieving any emissions reductions.

1.1.1 FORECAST COMPARISON OF EPA TO EIA

U.S. Energy Information Administration (EIA) in March 2023 released their Reference Case for the EIA 2023 Annual Energy Outlook, which includes the Inflation Reduction Act (IRA) tax credits, with new generation capacity additions for fossil generation summarized below. Since it came out in March, it does not include the EPA's GHG rule. However, it is relevant to compare to the EPA's numbers because the EIA's forecast is used by the entire power industry as a benchmark for future forecasting. The EIA uses its NEMS model for forecasting, while the EPA uses its own IPM model. The NEMS model has several advantages over the IPM model, which is why it is the standard bearer for the industry. One of the significant differences between the two models is that the NEMS model accounts for demand side management. Utilities use demand side management to cost effectively limit the amount of generation they need to build and burden the rate payers with. It is a valuable tool for managing the grid and the fact that it is not in the IPM model is a significant limitation of EPA's model.

Below is the EIA forecast.

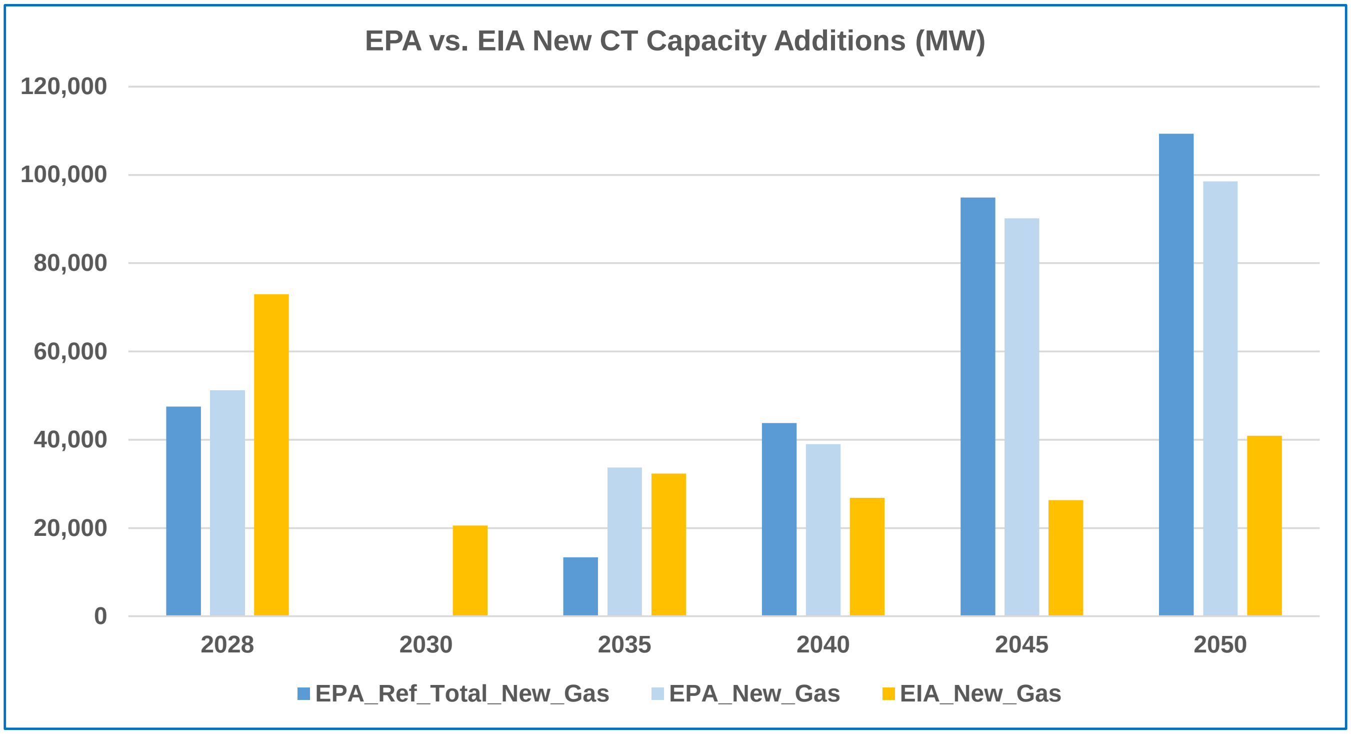
EIA: Reference Case (3/17/2023), Fossil Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	0	0	0	0	0	0	0
New_Gas_CCS	0	0	0	0	0	0	0	0
Retrofit Coal_CCS	0	0	0	0	0	0	0	0
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Retire_Coal	0	24,519	10,949	14,119	2,184	4,344	56,116	2,806
Retire_Gas	0	1,590	8,349	466	2,061	2,243	14,709	735
Total_Retire_CG	**0**	**26,109**	**19,298**	**14,585**	**4,245**	**6,587**	**70,824**	**3,541**
New_Gas_CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
New_Gas_CT	54,178	17,246	27,672	25,053	26,074	30,236	180,458	6,684
Total_New_Gas	**72,968**	**20,542**	**32,323**	**26,860**	**26,291**	**40,906**	**219,890**	**8,144**
Source: EIA, 2023 Annual Energy Outlook, NEMS Model (3/17/2023)								

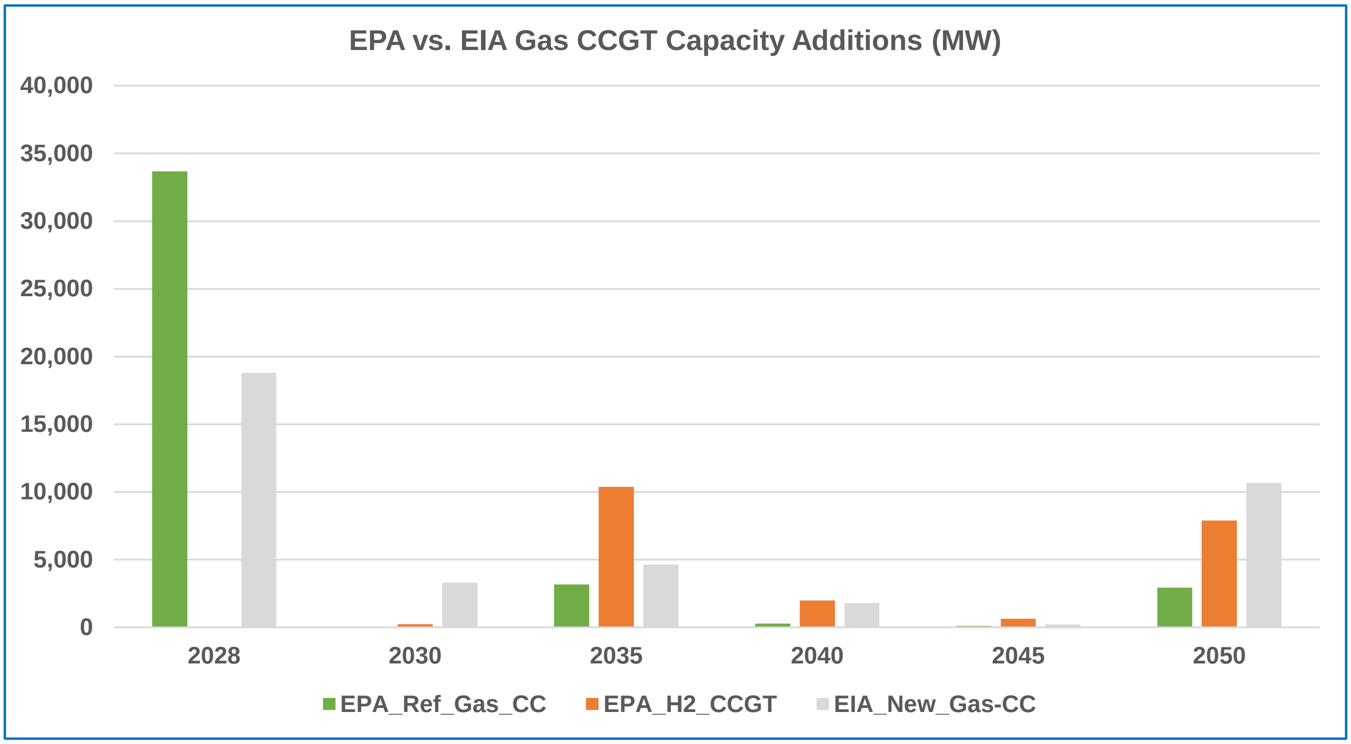
Over 2023-2028, EIA is projecting that 18,790 MW new gas-CC and 54,178 MW new gas-CT, totaling 72,968 MW will be built. Beyond 2028, EIA is projecting gas-CCGT additions ranging 20-40 GW in 5-year intervals, or annual gas additions over 2023-2050 averaging 8.1 GW per year.

A forecast comparison of EPA (CO2 Rule, Reference Case and Proposal Case) to EIA (AEO 2023 Ref Case) for new gas-CCGT and H2-CCGT generation additions (MW), in 5-year intervals, is summarized in the table and chart below.

Forecast Comarison: EPA CO2 Rule (5/11/23) vs. EIA 2023 AEO (3/17/23), Gas-CCGT Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	2023-2050	MW/Yr
EPA Reference Case								
EPA_Ref_Total_New_Gas	47,497	0	13,389	43,814	94,876	109,325	308,901	11,441
EPA_Ref_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
EPA Ref_%New_Gas-CC	71%	0%	24%	1%	0%	3%	13%	13%
EPA Proposal Case								
EPA_New_Gas	51,183	123	33,734	38,979	90,133	98,518	312,669	11,580
EPA_H2_CCGT	0	233	10,382	1,997	632	7,887	21,131	1,057
EPA_%H2-CCGT	0%		31%	5%	1%	8%	7%	9%
EIA Reference Case								
EIA_New_Gas	72,968	20,542	32,323	26,860	26,291	40,906	219,890	8,144
EIA_New_Gas-CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
EIA_%New_Gas-CC	26%	16%	14%	7%	1%	26%	18%	18%

The table above is presented in graphic form in the two graphs below. The first graph is the total gas generation, and the second graph is the likely hydrogen fired gas generation.


EPA vs. EIA New CT Capacity Additions (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Total_New_Gas
EPA_New_Gas
EIA_New_Gas


EPA vs. EIA Gas CCGT Capacity Additions (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Gas_CC
EPA_H2_CCGT
EIA_New_Gas-CC

1.1.2 CONCLUSIONS REGARDING EPA FORECASTS

There are several key conclusions that can be made from the above data:

- It may be difficult to make direct a comparison of the EIA data with the EPA proposal case since the EPA proposed data case considers the EPA proposed rule. It is for these reasons that Kiewit evaluated the EPA reference case as well.
- When comparing the EPA reference case to the EIA cases, it is concerning that the EPA case has so much more total combustion turbines forecasted than the EIA. It has almost 50 percent more combustion turbines forecasted as being built between now and 2050. This is likely a result of requiring plants to operate at less than a 50% capacity factor to maintain compliance, which again causes more plants to be built, more capital to be expended, but without any net reduction in emissions.
- Compared to the EIA, the EPA's estimates for combustion turbine generation requirements appear to be underestimated, despite overestimating total combustion turbine needs. The EIA is indicating that typically between 15 and 25 percent of new gas generation is combined cycle, whereas the EPA percent is between 0 and 10 percent. The result is a significant difference in potential hydrogen needs.

Total Potential Hydrogen Needs

Forecast	Total New MWs 2028 to 2050
EPA_H2_CCGT	21,131
EIA_New_CCCT	39,432

- The EIA's model represents the industry benchmark forecasting and planning. One of its benefits is that it does a better job of accounting for demand side management than does the EPA model. Therefore, its total energy needs are more accurate starting point for this analysis than the EPA's.

1.1.3 REVIEW OF ADDITIONAL EPA MODELING

On July 7, 2023, EPA released additional modeling in support of the proposed rule. The additional modeling reflects EPA's analysis of the integrated proposal (i.e., modeling the requirements on existing combustion turbines) and the third phase after 2040 of the NSPS together with the requirements that were already modeled as part of the Regulatory Impact Analysis for this rulemaking. Additionally, the analysis also separately projects illustrative impacts of higher LNG export demand consistent with the recently released EIA annual energy outlook AEO 2023. The EPA changed assumptions for natural gas prices and LNG prices in the IPM model scenarios for the Updated Baseline scenario and the Illustrative Integrated Proposal scenario, and *"exogenously"* evaluated the potential for hydrogen co-firing in existing combustion turbines, which were not evaluated in EPA's original Proposal case. This means that they evaluated hydrogen co-firing on existing turbines ***outside*** of the main model. It is difficult to know what this fully means, but it does appear that the existing combustion turbines were not fully integrated into the main model.

We draw attention to the following statements from EPA's memo of July 7, 2023, with concern as stated:

- The EPA indicates that 17 GW of NGCCs and 6 GW of NGCT additions will co-fire hydrogen in 2035.
- In 2040, the EPA forecasts that 1 GW of NGCC and 6 GW of NGCT additions are projected to continue to co-fire hydrogen.
- Of the existing NGCC units greater than 300 MW, 25 GW are projected to co-fire hydrogen in 2035 and 5 GW are projected to co-fire hydrogen in 2040.

- Table 22 (Integrated Proposal with LNG Update) shows additional hydrogen co-firing of 48 GW in 2035, and 12 GW in 2040.
- There is a discrepancy in EPA's estimate of additional hydrogen co-firing (2035, 25 GW vs 48 GW) in Table 22.
- EPA did not state the percentage of hydrogen co-firing in existing gas-CC over 300 MW size assumed.
- While proposed CO2 Rule requires minimum 30% co-firing of hydrogen in 2032, most existing gas-CC over 300 MW size do not have the capability to co-fire 30% hydrogen, and EPA did not evaluate how they would be retrofitted to maintain capacity.
- The economics of retrofits to existing gas-CCs over the 300 MW size to be capable of co-firing 30% hydrogen does not appear to be evaluated in EPA's analysis.

Kiewit has the following concerns with the July 7, 2023, modeling:

- The EPA did not provide a complete set of information on the July modeling, as they did with the original modeling. As a result, it is impossible assess the validity of this additional modeling.
- The modeling was provided extremely late in the comment period and, therefore, there was not time to analyze this information appropriately. Yet, EPA is presenting it as justification along with the rest of information as equal justification.
- By the EPA's own admission, the modeling of the existing combustion turbines is not fully integrated into the rest of the model. So, as a result, it is unknown whether they are being modeled correctly or whether they are accurately interacting with the rest of the grid.
- As will be discussed further in this report, it does not appear that the EPA has accounted for the fact that units retrofitted for hydrogen firing will not be able to maintain their original capacity without significant retrofit. This is a significant economic hit to these turbines that has not been modeled.

In summary, the lateness of the EPA's additional modeling, the way it was performed (i.e., outside of the IPM model), and the fact it does not account for lost capacity, make the July 7, 2023 modeling results extremely questionable and unreliable. In Kiewit's opinion, they cannot be depended on for policy decisions.

1.1.4 EPA COMMENTS ON HYDROGEN

EPA incorrectly assumes hydrogen firing will not impact the capacity of affected units.

EPA's Resource Adequacy Analysis document incorrectly asserts that:

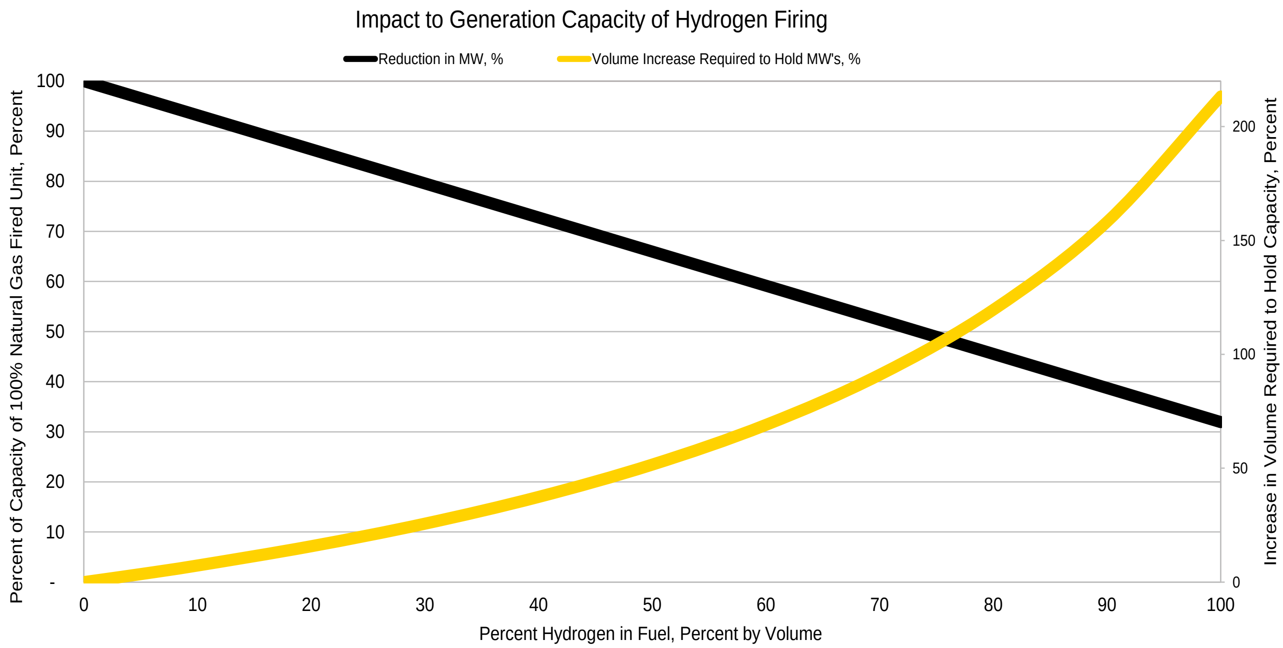
> *"For both the affected units that reduce capacity factor to 50% and those that increase hydrogen co-firing to 96% by volume, unit capacity accreditation and the amount that they contribute to resource adequacy is unchanged, as there is no capacity derate for hydrogen co firing."*

[CITE at p. 8.]

It is important to understand that capacity refers to a unit's maximum electric output, while capacity factor refers to the fraction of a unit's total available capacity utilized over a period of time. Hydrogen co-firing at 96% is likely to negatively affect a unit's capacity. That is because hydrogen has an energy density that is roughly 1/10th of natural gas. Therefore, even though the heating value of hydrogen is higher than natural gas, the increased heating value does not make up for the lower energy density. The EPA acknowledges this difference in its Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units" on Page 3:

> *"One of the differences between hydrogen and natural gas is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas."*

This difference in energy density means that for a combustion turbine to achieve the same capacity burning hydrogen as it would with natural gas, it would need to fire significantly more hydrogen. The graph below shows this impact.



The black line on the graph shows how the capacity of a unit changes as hydrogen firing is increased. For example, if hydrogen provides 70 percent of the fuel (by volume), the capacity of the unit will drop to 50% of the MW's it could produce when it was firing natural gas. When the unit is firing 96% hydrogen, it can only produce approximately 35% of the MW's that could produce when firing natural gas. So, to maintain the same MW production in a combustion turbine that is firing 96% hydrogen, a utility would have to fire almost 200% more fuel. The yellow line on the graph shows this. As such, a combustion turbine burning 96% hydrogen would have a significantly lower capacity.

To the extent that EPA is referring to capacity factor, its assertion is equally unsupported. A unit burning 96% hydrogen would have 65% less capacity than the same unit burning natural gas. For example, for a 100 MW unit firing natural gas, the same unit firing 96% hydrogen would have a capacity of 35 MW. Even if one were to assume that the unit's availability and utilization were the same (an assumption that is speculative because there is no history or data with which to assess the reliability of units burning 96% hydrogen since they do not exist), its capacity factor would be lower. That is because capacity factor is expressed as capacity in MW / utilization. And since the capacity will have decreased, so will the capacity factor.

For EPA's assertion to be true, the combustion turbine would have to burn approximately 200% more fuel to provide the same amount of power. It is unlikely that every unit can be designed or retrofitted to do so. Among other reasons, combustors would have to be converted for a much larger flow rate, which may or may not be possible. It would also require that the fuel supply system and the control system would need to be modified to handle 200% more flow, again it is unlikely to be possible on all the units where this would be needed. In addition, to our knowledge, it has not yet been attempted. The HRSG and emissions control equipment would also need to be able to handle the additional exhaust. Even if a few units could make such changes, it is unlikely that these changes will be able to be made on a consistent basis, system wide, to maintain capacity.

In short, EPA's assumption that 96% hydrogen firing will allow existing units to maintain their capacity is incorrect. Instead, the proposed rules would likely require significant additional generation to be built to make up for the loss of generating capacity because of switching to hydrogen. The EPA did not model this.

1.2 HYDROGEN IN COMBUSTION TURBINE EGUS

To support its assertion that hydrogen co-firing is ready for implementation on a large scale, EPA provides a list of new hydrogen firing projects on pages 8 and 9 of its Hydrogen in Combustion Turbine Electric Generating Units technical support document. The list fails to support EPA's conclusions.

Below is the list of projects in EPA's report, along with the total MWs and some additional comments on these projects. It should be noted that several of these projects are Kiewit projects.

Facility	Total MW[1]	Initial Hydrogen Firing	MW of Hydrogen[2]	Comments
Long Ridge Energy Center*	485	5%	24	Not green hydrogen, can only operate on hydrogen 45 minutes at a time
Intermountain Power Agency*	840	30%	250	Not yet operational
LADWP	297	30%	89	Not operational on hydrogen until 2029
Lincoln Land Energy Center	1,100	30%	~230	Not operational
Newman Power Station	178	30%	50	Not currently operational on hydrogen
Orange County Advanced Power Station*	1,215	30%	250	Design not started yet; EPA's description does not specifically indicate green hydrogen
Magnolia Power Plant*	725	50%	200	Not operational until 2025, capable of 50% H2 firing if hydrogen is available, EPA's description does not specifically indicate green hydrogen
Total	4,840		1,093	

Notes:

1. **Total MW = Total MW's that will be produced by the facility**.
2. MW of Hydrogen = Total MW's that will be produced from firing hydrogen initially (not including power from steam turbines). In all cases, 100% hydrogen firing is aspirational.
3. The (*) indicates Kiewit projects.

The only one of these units that is in operation and using hydrogen firing is the Long Ridge Energy Center. Long Ridge Energy Center's onsite storage only allows for firing up to 5% hydrogen. In addition, the facility can only fire hydrogen for 45 minutes before it runs out of storage. The other units on this list are all in the planning, design, or construction stage. None of the other units are in operation. In addition, none of these units are expected to fire anywhere close to 96% hydrogen initially. Instead, they expect to burn between 30-50% hydrogen, with an aspirational goal of having the capability of firing more.

Second, it should be noted that the timeline for most of these projects to be firing 100% hydrogen is 2045. This is significant since these units are the *early adopters*, with high aspirations for firing hydrogen. The 2045 date of these units, which the EPA presents as examples of what is possible with hydrogen firing, does not support EPA's 2038 deadline for 96% hydrogen firing.

In addition to the technical concerns discussed above, the list in the table represents an exceedingly small proportion, less than 0.1 percent, of the US combustion turbine fleet. While it may indicate that the industry is moving towards the technical ability to fire hydrogen, the EPA has not made (and cannot make) the case that the industry can meet the demands for hydrogen firing that this rule would require. Hydrogen transportation, availability, along with capability of combustion turbines all play a part in why the industry is not ready for this challenge, as will be discussed later in the report. But the timeline presented by EPA in the regulations is too aggressive.

2. HYDROGEN COMBUSTION

This section will discuss the industry status of hydrogen combustion in combustion turbines.

2.1 CAPABILITY OF COMBUSTION TURBINE OEMS

2.1.1 HYDROGEN FIRING

The capability of the turbine OEMs for hydrogen firing, as reported by the EPA, are shown in EPA's table on Page 7 of EPA's Hydrogen in Combustion Turbine Electric Generating Units technical resource document:

Manufacturer	Turbine Model/Type	Current Hydrogen Capability[1]	Future Hydrogen Capability[2]
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%

[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors.
[2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_x. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.

Figure 2: Hydrogen Capabilities in Certain Models of Combustion Turbines

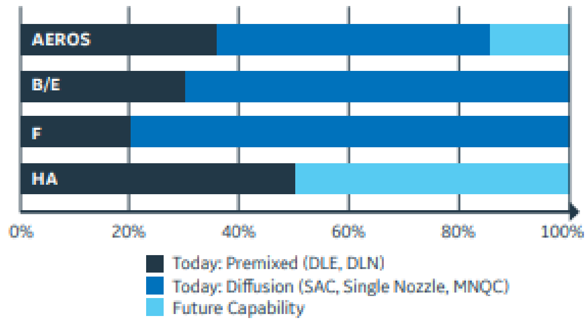
The current capability of burning hydrogen varies based on the OEM and the classification of combustion turbine. The table below is a summary of the capabilities and future target capabilities from the three (3) largest combustion turbine manufacturers from their respective websites.

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
Aeroderivative	30-100% depending on OEM	100%	2025-2030
B/E Class	30-100% depending on OEM	100%	2030
F Class	20-100% depending on OEM and combustor	100%	2030

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
G Class	30%	100%	2030
H Class	30-50%	100%	
J Class	30%	100%	2030

The numbers shown in EPA's table are misleading, especially for the larger frame units (F, G, H and J Class). For the GE Frame F, EPA indicates that GE can fire 100 percent hydrogen. However, GE indicates that the unit must use GE's Single Nozzle combustor (aero derivatives) or the multi-nozzle quiet combustor (frame CT's), as seen from the figure below. These combustors produce higher NOx than the dry low NOx (DLN) combustors. As of today, GE's DLN combustor can only burn between 20% and 30% hydrogen. If utilities switch away from DLN combustors to allow for more hydrogen combustion, it will increase NOx emissions from 9 ppm to 25 ppm.

Current status of GE turbines hydrogen capabilities (%vol)



Each of the three largest combustion turbine manufacturers aspire to construct 100% hydrogen fired units by 2030. However, as acknowledged by the Department of Energy National Energy Technology Laboratory's (DOE/NETL) white paper titled "A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control" (https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf); there are some major obstacles to overcome before those aspirations could be realized. Gas turbine combustors are designed to work at specific operating pressures and with a fixed volume with little room for variation. To accommodate the hydrogen fuel, the turbines will either need to be larger, use higher max pressures to reduce the hydrogen volume or both. To achieve a similar performance and emissions from a hydrogen fired turbine will cost more to produce than its natural gas fired counterpart because of the higher volumes and/or pressure requirements.

Hydrogen has a higher flame temperature, faster flame speed, and creates a higher concentration of H• radicals than natural gas, which presents some additional areas of concern for the turbine manufacturers. The higher flame temperature causes increased metal temperatures, while the higher flame speed, and particularly higher concentration of H• radicals, creates the potential for higher thermal NOx emissions and changes to thermal acoustics. These factors cause vibrations that could potentially destroy the turbine combustors. The increased metal temperatures will require localized cooling or other technique to protect parts of the turbine from thermal stresses.

One of the largest concerns with making the transition to 100% hydrogen-fired combustion turbines is the increased flame speed. Hydrogen's flame speed is an order of magnitude faster than natural gas. The higher flame speed can also increase the local flame temperature (added to the higher natural flame temperature) which accentuates the issues described above. The increased flame speed also causes concerns with flame stability within the combustion turbine. If the flame speed is higher than the fluid velocity, there will be "flashback" into the fuel mixing zone, which causes damage to the injectors and other components. If the fluid velocity is increased to avoid flashback, there is the possibility of blowout, where the flame is extinguished. This creates a challenge for the combustion turbine manufacturers, to design the combustion system to maintain the flame stability, while also designing the turbines to handle the higher temperatures and/or pressures of the hydrogen fuel.

Regarding retrofits, as stated before in Section 1.2, there is no guarantee that the capacity of CT's will be maintained when switching to hydrogen from natural gas. With the higher flame speed and temperatures of hydrogen, retrofitting the existing combustion turbines will not be as simple as switching out the combustors. If the fuel velocity is increased to eliminate flashback, this will cause increased pressure drop across the combustor, which will have an impact on the reliability, maintenance schedule and life expectancy of the turbines.

Also of note is that the combustion turbines that can currently burn the higher percent of hydrogen are the aeroderivative and smaller combustion turbines. These smaller units are typically used as peaking units and are not typically base loaded turbines; therefore, they are not likely to be impacted by the EPA requirements. Most base load facility utilize the larger frame (F, G, H and J Class) in either simple or combined cycle configurations. The larger frame units are more efficient which makes them a better solution for base load operation.

Finally, as stated in Section 1.1.4, existing heavy duty frame gas turbines will require a new combustion and fuel system to burn the higher rates hydrogen because higher volumes of hydrogen will be required to maintain capacity. In addition, retrofit costs have not been fully assessed for converting to hydrogen, nor has the downtime required to make the conversion.

2.1.2 AMMONIA FIRING

For ammonia firing, the following information has been provided by the OEM's.

Combustion OEM	Class Size	Current Capability	Future Capability
Mitsubishi	Smaller Frame Sizes Larger Frame Size	None None	100% Planned by 2026 None
GE	6F, 7F	None	100% by 2030

EPA's proposal is unclear as to whether the agency intends to allow ammonia firing as a form of hydrogen firing. However, ammonia firing information is being presented here because there would be some advantages to being able to fire ammonia instead of hydrogen. Those advantages have to do with transportation and storage infrastructure. Ammonia is already a common commodity in the US because it is used for fertilizer. The regulations for storage and transport are well established and it is much more commonly transported than hydrogen. However, as can be seen by the table above, there is limited effort being made by the OEMs to develop ammonia firing capability. Therefore, ammonia is unlikely to significantly change the US's ability to implement widespread hydrogen firing.

2.2 OPERATING IMPACTS OF FIRING HYDROGEN

Within each combustion turbine class, there are different turbines each with different current capabilities for burning hydrogen. Using the current hydrogen capability of each turbine we calculated how much hydrogen (kg) each turbine can burn currently and divided that by the output of the combustion turbine to get the amount of hydrogen required per megawatt of power. Below is a table which shows the hydrogen required to generate 1 MW of power output for each of the turbine classes averaged across all the combustion turbine OEMs. The table also shows how much hydrogen would be required in each of the turbine classes to burn 100% hydrogen, again averaged across each of the OEMs. Using electrolysis to create hydrogen requires both demineralized water and auxiliary power. Electrolysis is the process of splitting water into hydrogen and oxygen using electricity. The demineralized water and auxiliary power required shown below is based on using Proton Exchange Membrane (PEM) electrolysis for generating hydrogen and is representative of various electrolyzer OEMs.

Turbine Class	Output Range	Hydrogen Req'd Current Capability	Hydrogen Req'd Future Capability	Demin Water Req'd Current Capability	Demin Water Req'd Future Capability	Aux Power Req'd Current Capability	Aux Power Req'd Future Capability
Units	(MW)	(kg/MW)	(kg/MW)	(gal/MW)	(gal/MW)	(MW/MW)	(MW/MW)
Aeroderivative	5-65	14	25	0.66	1.18	0.764	1.364
B/E Class	75-120	15	25	0.71	1.18	0.819	1.364
F Class	170-250	7	23	0.33	1.09	0.382	1.255
G Class	225-285	7	22	0.33	1.04	0.382	1.201
H Class	275-390	9	21	0.43	0.99	0.491	1.146
J Class	330-430	6	20	0.28	0.95	0.327	1.091

As shown from the table above, the amount of hydrogen required per MW is larger for the smaller combustion turbines. These turbines are less efficient and require more fuel per MW than the larger turbines. The table also shows that for all combustion turbine classes, **the auxiliary power required to create hydrogen using PEM electrolysis is greater than the power generated by burning 100 percent hydrogen in a combustion turbine.** Such basic energy balance shows that firing hydrogen in combustion turbines is a net energy loser rather than a net energy producer. It is neither possible nor practical to require more auxiliary power than the power generated by the combustion turbine, this would create a significant reduction in energy capacity in the grid, thus resulting in a significant increase in overall construction, which defeats the overall goal of reducing greenhouse gases.

2.3 ONSITE STORAGE REQUIREMENTS

The hydrogen required for each turbine classification in the table above were used to calculate the hydrogen storage required and is shown below for both 1- and 5-days storage. The storage criteria is consistent with the current storage philosophy used at power generating facilities. The table below shows how much hydrogen would need to be stored to meet the current hydrogen capability as well as the future target capability of 100% hydrogen. The values shown below are based on a single MW output for each of the turbine classification ranges. The storage pressure of hydrogen is assumed to be 2,500 psi. When calculating how much hydrogen needs to be stored the assumption is that no onsite compressors will be used to send hydrogen from the storage to the combustion turbines which means there will always be a certain amount of hydrogen in the storage. Using the turbine gas supply pressure requirement and accounting for pressure losses between the onsite storage and the combustion turbines shows that you need to store ~32% more hydrogen than the turbine requires. The values below show how much hydrogen needs to be stored to generate the power output shown.

Turbine Class	Output (MW)	Current Hydrogen Capability Stored (1 Day) (kg)	Future Hydrogen Capability Stored (1 Day) (kg)	Current Hydrogen Capability Stored (5 Day) (kg)	Future Hydrogen Capability Stored (5 Day) (kg)
Aeroderivative	65	28,829	51,480	144,144	257,400
B/E Class	120	57,024	95,040	285,120	475,200
F Class	250	55,440	182,160	277,200	910,800
G Class	285	63,202	198,634	316,008	993,168
H Class	390	111,197	259,459	555,984	1,297,296
J Class	430	81,734	272,448	408,672	1,362,240

Based on the storage requirements in the above table, onsite, above ground storage would be as shown in the table below. There are options for underground storage of hydrogen, but those are currently limited to salt caverns which are not widely available throughout the US. Accordingly, aboveground storage was assumed for this evaluation because that would be available at more power generation facilities than underground salt caverns.

Turbine Class	Output (MW)	Number of Tanks (1 Day) Current/Future	Number of Tank (5 Days) Current/Future	Truck Deliveries to Fill the Tank (1 Day of Storage) Current/Future	Truck Deliveries to Fill the Tank (5 Day of Storage) Current/Future
Aeroderivative	65	16 / 28	77 / 138	46 / 83	233 / 416
B/E Class	120	31 / 52	153 / 255	92 / 153	460 / 767
F Class	250	30 / 98	149 / 489	89 / 294	448 / 1,470
G Class	285	34 / 107	170 / 533	102 / 320	510 / 1,602
H Class	390	60 / 140	298 / 696	179 / 418	897 / 2,093
J Class	430	44 / 147	219 / 731	132 / 439	660 / 2,198

Note:
Truck delivery assumes all truck deliver in a 12-hour period. Each truck delivery contains 310 kg. Each tank holds 1,863 kg.

Most facilities store backup fuel supplies (1 to 5 days) on site to guard against infrastructure and transportation disruptions. Accordingly, it is reasonable to assume that they would similarly do so with hydrogen, especially because of the high degree of uncertainty and unknowns surrounding the current and future hydrogen infrastructure. Even with only 1 day of hydrogen storage onsite, a generating facility would be significantly hampered in its ability to continue generating power during supply disruptions.

Each tank would require approximately 1,500 ft^2 of land. For 1 day of storage for an H-Class turbine requiring 140 aboveground tanks that would require approximately four acres of storage tanks. If 5 days of storage was used for the H-Class turbine that would be approximately 17 acres for the storage tanks. The required storage area will be a concern for many existing facilities. There will also be safety and fire protection implications for storing this amount of hydrogen aboveground, including zoning restrictions.

The tables above show that truck delivery and storage of even a small amount of hydrogen onsite is not practical. For an F-Class turbine, the facility would need to receive 294 trucks in a 12-hour period to maintain the 1-day storage. To do that, each truck would need to unload in less than 2.5 minutes; For H-Class turbines that would have to be done in 2 minutes. It is not possible to have trucks pull into site and unload in less than 3 minutes.

A more realistic duration for truck deliveries would be 30-60 minutes for each truck. With the trucks being unloaded 12 hours per day, it would take between 12 and 24 days to unload the number of trucks for a single F-Class turbine to provide 1 day of hydrogen storage. It would take between 17 and 35 days of truck deliveries for a single H-Class turbine and 1 day of storage. Many existing power generation facilities have multiple combustion turbines on their site, which would cause even longer durations and larger tanks requirements on the site.

Even if a facility could be designed to include the number of tanks required in the tables above, additional infrastructure would be required to upgrade the roads to the plant to be able to handle hydrogen tanker trucks arriving to and leaving from the plant every 2 minutes. These roads would have to be designed all over the country for the same situation, as hydrogen would be delivered to many facilities throughout the U.S. In addition, the delivery travel from the hydrogen production facilities to these power plants would place a lot of wear and tear on road.

2.4 IMPACT ON NO_X EMISSIONS

One of the potential environmental impacts of firing hydrogen is the potential increase in NOx emissions. As stated on Page 4 and 5 of the EPA's Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units":

> *"The technical challenges of co-firing hydrogen in a combustion turbine EGU result from the physical characteristics of the gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.12 A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NOx emissions. It is necessary in combustion for the working fluid flow rate to move faster than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as "flashback" occurs, which can damage injectors or other components and lead to upstream complications.*
>
> *Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F) and a wider flammability range for hydrogen than natural gas.16 It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can also lead to formation of greater volumes of NOx.*
>
> *Combustor modifications or retrofits have the potential to limit NOx emissions. For example, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is an option for combined cycle turbines. For combined cycle plants planning to co-fire higher volumes of hydrogen over time, it is important to estimate the increased NOx emissions when sizing the SCR unit."*

The EPA has therefore acknowledged that NOx will go up in many cases for combustion turbines firing hydrogen. While the combustion turbine OEMs have not yet expressed significant concerns with increased NOx emissions at the 30% hydrogen firing case, there is no testing data available to show that NOx emissions will not be a problem. Especially in the case of retrofitting existing combustion turbines, where the OEMs will have less flexibility to make changes, the potential for increasing NOx emissions is higher, even at 30% hydrogen firing.

In addition, while the OEMs are working to produce dry low NOx (DLN) hydrogen combustors that can maintain lower NOx emissions in the future, it is uncertain whether they will be successful at maintaining the levels that are currently achievable. As with the 30% hydrogen firing case, the OEMs' ability to keep NOx low is most limited for the combustion turbines that are retrofitted to fire hydrogen.

Finally, as discussed in detail above in Section 1.1.5, when a unit fires 96% hydrogen, it will need to fire almost 200% more fuel to maintain the same capacity. A combustion turbine firing more fuel will also produce more NOx emissions because of the increase in the fuel being fired. So, hydrogen firing is potentially a double hit on NOx emissions: 1) because it results in a higher concentration of NOx emissions and 2) because the mass of emissions is higher due to more fuel being used.

3. HYDROGEN STORAGE AND TRANSPORT

3.1 HYDROGEN HUBS

It is believed that approximately 20 hydrogen hubs in the US submitted final applications by April 7, 2023 deadline to the US Department of Energy (DOE) for "regional clean hydrogen hubs" funding up to $1.25 billion (out of total of $7 billion) available for an expected 6-10 clean hydrogen hubs that will be awarded by 2030. Concept papers for the Hubs were due on November 7, 2022, and full applications were due on April 7, 2023

The ultimate winners of the DOE hydrogen hub funding selection process may not be known for some time. According to the DOE's funding opportunity announcement, the application period that concluded on April 7 leads into the first phase of the selection process, in which the DOE will dole out up to $20 million to hubs with a 50% minimum cost matching requirement following the merit review process. That phase will span 12 to 18 months during 2023-2024.

Then, awardees move into a "negotiated go/no-go" process in 2024 before moving into phase two, where they can receive up to 15% of each hub's total requested amount. This phase can take up to 2-3 three years by 2026-2027.

Once in phase three by 2027, the DOE will begin releasing the remaining 85% of federal funding on an undefined schedule while closely monitoring each hub's implementation process -- a stage that could take 2-4 years by 2029-2031. In the final fourth stage, hubs will transition to their operational stage after 2031.

It should be noted that the other side of this equation is the "Regional Clean Hydrogen Hubs Demand-side Support Notice of Intent." Responses were due by July 24, 2023. This is where parties interested in receiving hydrogen from the hubs are requested to provide notice to the DOE. This timeline is vastly out of step with the timeline for the GHG rule that the EPA has established. As defined in Section 2.3, combustion turbine units that are firing 30% or 96% hydrogen are not going to be able to have a lot of onsite storage of hydrogen because hydrogen has such a low density that makes onsite storage impractical. As a result, utilities will need to depend on hydrogen transport through pipelines for hydrogen supply. Therefore, the infrastructure created by these future hydrogen hubs will represent most of the US supply storage for hydrogen for the foreseeable future. Unfortunately, because of the 2035 and 2038 timelines in the EPA's rule, utilities will have already missed their deadline to notify the DOE of their interest in reserving supply in the hydrogen hubs. As a result, there is no guarantee that the hubs will be sized to meet the hydrogen needs of combustion turbines built or retrofitted to meet the EPA rule. Currently, there is no hydrogen fuel storage constructed to supply the needs for the combustion turbine fleet and no pipelines available for transportation.

3.2 HYDROGEN PIPELINES

As stated previously, to supply hydrogen to combustion turbine units firing hydrogen, most of the hydrogen will need to come from hydrogen hubs because onsite storage is impractical. However, there are many concerns with conveying hydrogen in pipelines. As EPA has acknowledged:

> *"Hydrogen blends of up to 5 percent in the natural gas stream are generally safe. However, blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.*
>
> *Hydrogen blends of more than 20 percent present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.*
>
> *Analysts assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required. Other recent analyses of existing pipeline materials indicate that 12 percent may be the maximum blend. In addition, the existing end-use equipment in power plants and industrial facilities may not tolerate higher hydrogen concentrations without modification. If implemented with relatively low concentrations, less than 5 to 15 percent hydrogen by volume, this*

strategy of storing and delivering low-GHG hydrogen to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis."

Indeed, these concerns are well documented in other sources, such as:

- "Once hydrogen enters pipelines, it can weaken metal pipes which can lead to cracking. Hydrogen is also far more explosive than natural gas which could create safety issues." – *"Focus: Has green hydrogen sprung a leak?,"* By Sarah Mcfarlane and Ron Bousso, December 22, 2022
- "It is well known that the presence of hydrogen increases fatigue crack growth rates in commonly used pipeline steels, and studies have shown that metals with higher tensile strength tend to experience greater reductions in fracture resistance than metals with lower tensile strength when in contact with hydrogen. Recent research has shown that fatigue crack growth and fracture resistance can degrade even with low partial pressures of hydrogen, with subsequent degradation being more modest as the partial pressure is increased. In high-stress situations, fatigue crack growth is fairly independent of hydrogen concentration." – *"Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,"* National Renewable Energy Laboratory, University of Colorado Boulder, Sandia National Laboratories, Pacific Northwest National Laboratory, October 2022

The potential for pipeline leaks is of significant concern because these pipelines will need to be routed in areas where the public lives and works, resulting in potential hazards associated with gas ignition in populated areas.

The potential for embrittlement of pipeline material is a well-known phenomenon with hydrogen. This increases the potential for leaks. In addition, embrittlement increases the maintenance potential and inspection requirements on the pipeline. Given the quantity of pipelines that will be required to supply hydrogen to hydrogen-fired combustion turbines throughout the country, the inspection and maintenance requirements will become challenging, especially in populated areas.

Finally, these quotes establish that transporting 96% to 100% hydrogen is especially challenging. Yet, to meet the proposed requirements, the hydrogen transport piping will need to be able to transport this high concentration of hydrogen to supply 96% fired combustion turbines. The EPA's discussion of pipelines does not address the significant challenges of this transport piping at all.

In addition to the above discussions about the technical challenges with hydrogen transport piping, the EPA acknowledges the cost challenges associated with hydrogen transport piping:

"The capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure."

As such, the hydrogen supply will be hindered by the cost of transporting the hydrogen. It is simply not practical to resolve such costly technical, engineering, let alone complete construction of an entirely new nationwide pipeline system in the timeframe and cost estimates assumed by EPA. In addition, unlike hydrogen used for transport vehicles or for shipment overseas, combustion turbines firing hydrogen need to be located in a distributed manner to meet power delivery requirements. As a result, expansive hydrogen pipeline infrastructure will be essential to the feasibility of hydrogen firing for power productions.

3.3 QUANTITY REQUIREMENTS

On Page 25 of the Technology Support Document ""Hydrogen in Combustion Turbine Electric Generating Units", the EPA indicates that "approximately 1,600 miles of dedicated hydrogen pipelines are deployed in regions of the U.S." According to the Congressional Research Service Report, "Pipeline Transportation of Hydrogen: Regulation, Research, and Policy," published March 2, 2021, 90% of that pipeline is located along the Gulf Coal in Texas, Louisiana, and Alabama. "By comparison, there are over 300,000 miles of U.S. natural gas transmission pipeline (not counting distribution mains) located in the 48 contiguous states and Alaska." From a comparison perspective, this means there are almost 200 times more miles of natural gas pipelines in the country than hydrogen pipeline. This comparison is important because it demonstrates the infrastructure needed for natural gas to be a critical part of the US's energy supply and gives an indication of the magnitude of need for hydrogen supply pipelines. To meet EPA's goals a pipeline network close to the size of the existing (and expanding) natural gas pipeline network would need to be constructed on a timeline never before seen.

This is not speculation. According to EIA, through 2021 there were over 800 combustion turbines, in 47 states, in the US being used for power production. This demonstrates that the use of combustion turbines for power is widely distributed throughout the US. In addition, as stated previously, hydrogen supply cannot be provided by onsite storage since that is unpractical. Therefore, hydrogen supply to support hydrogen firing will need to be provided through hydrogen pipelines.

The hydrogen pipeline must reach more areas than just the current 1,600 miles along the Gulf coast and must have a reach that is much more like the 300,000 miles of natural gas pipelines that the country currently has to support combustion turbines spread through the country. In fact, while Kiewit has not calculated the exact need, the need is several orders of magnitude greater than the current pipelines available. Much of this pipeline will need to be routed in highly populated areas. Given the safety concerns discussed in Section 3.2, the issue of supply pipelines is a significant barrier to the practicality of the hydrogen requirements of the proposed rule.

4. HYDROGEN PRODUCTION

4.1 ELECTROLYZER OEMS

Electrolyzer manufacturers offering their products in the US consist of industrial conglomerates with an electrolyzer division such as Siemens, mature “pure play” manufacturers such as Plug Power and new start-ups with a successful lab experiment. Offerings vary from stack-only to complete plug and play packages.

We have identified twelve (12) manufacturers currently active in the US market. While this list is not exhaustive, it includes the majority of the players in the U.S. market. The different electrolyzer technologies are described below:

AEM – Anion Exchange Membrane

AWE – Alkaline Water Electrolysis

E-TAC – Electrochemical, Thermally Activated Chemical

PEM – Proton Exchange Membrane

SOEC – Solid Oxide Electrolyzer

In the table below, “capacity” indicates the amount of power required by the electrolyzer to produce hydrogen. This is the typical convention used when defining the size of electrolyzer capacity. The manufacturers in the table below have a combined 2023 capacity of approximately 12 GW of hydrogen production. Since every GW of electrolyzer capacity can produce an estimate 400 tons per day of hydrogen, this represents 4,800 tons per day of hydrogen production for 2023. **If all the electrolyzers forecasted for 2023 were built to produce hydrogen for combustion turbines, the forecasted hydrogen production for 2023 would provide enough hydrogen to fuel approximately 87 F-Class or 43 H-Class combustion turbines burning 100% hydrogen for just 1 day.**

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE(1)	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP(2) (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Bloom	SOEC	22	2000	$4,150	$1,199	($301)
Accelera (Cummins)	PEM, AWE	70+(3)	1600	$34,190	$28,074	$2,151
Enapter(4)	AEM	6	280	$344	$13,924	($10,291)
H2Pro	E-TAC	4	No Forecast	Private(5)	Unknown	Unknown
H-TEC(6)	PEM	26	0	$16,597	$138,009	$6,000
Hydrogen Optimized(7)	AWE	6(8)	No Forecast	Private	Unknown	Unknown
NEL	PEM, AWE	96	500	$2,330	$96	($122)
Ohmium	PEM	4	2000	Private(9)	Unknown	Unknown

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE[1]	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP[2] (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Plug	PEM	26	3000	$7,330	$701	($274)
Siemens	PEM	TBD	1300	$125,030	$78,028	$4,036
Sunfire[10]	AWE, SOEC	13	500	Private	Unknown	Unknown
ThyssenKrupp	AWE	100[11]	1500	$4,600	$43,336	`

1. Measured from date of incorporation.
2. As of 10 March 2023, PER S&P Global Intelligence
3. Includes Stuart Energy experience.
4. 2021 results
5. Has publicly announced 4 rounds of funding, most recent in January 2022, totaling ~$97m.
6. Owned by MAN Energy Solutions SE, a wholly owned subsidiary of Porsche Automobil Holding SE. Revenue and income 2022 forecasts for ultimate parent, Porsche.
7. Hydrogen Optimized technology is basically AWE, however they have a unique electrode arrangement that has not been deployed on a large scale.
8. The founders of Hydrogen Optimized, the Stuart family, has electrolysis experience of more than 100 years.
9. Series B funding round completed April 2022. Raised $45m, estimated valuation of $135m.
10. Has publicly announced 6 rounds of funding, most recent in July 2022, totaling ~$262m, with last available valuation of $1.7B. Revenue and net income from 2020.
11. Includes experience of De Nora

It should be noted that the above listed forecasted capacities are the nameplate capacities of the electrolyzer. If renewable energy is utilized as the power source for the electrolyzer, the actual output will be lower. The capacity factor, or amount of time energy is produced, for renewables is approximately 30%. So, the actual production of hydrogen could be 30% of the above listed values. Using the forecast data presented in Section 1.1.4, the hydrogen required is as follows:

Total Potential Hydrogen Needs for New Units

Forecast	Total New MWs 2028 to 2050	**Hydrogen Needs, tons per day**
EPA_H2_CCGT	21,131	14,000
EIA_New_CCCT	39,432	26,233

This does not include any other uses for electrolyzers, including international uses and other US uses. It also does not include any existing combustion turbine facilities that will require hydrogen retrofits. This indicates that a significant increase in electrolysis project manufacturing and execution would be required to meet the hydrogen needs required by the EPA. Bottom line, the electrolyzer industry is simply not suitable to meet the demand that would be put on the industry if EPA's rule is passed.

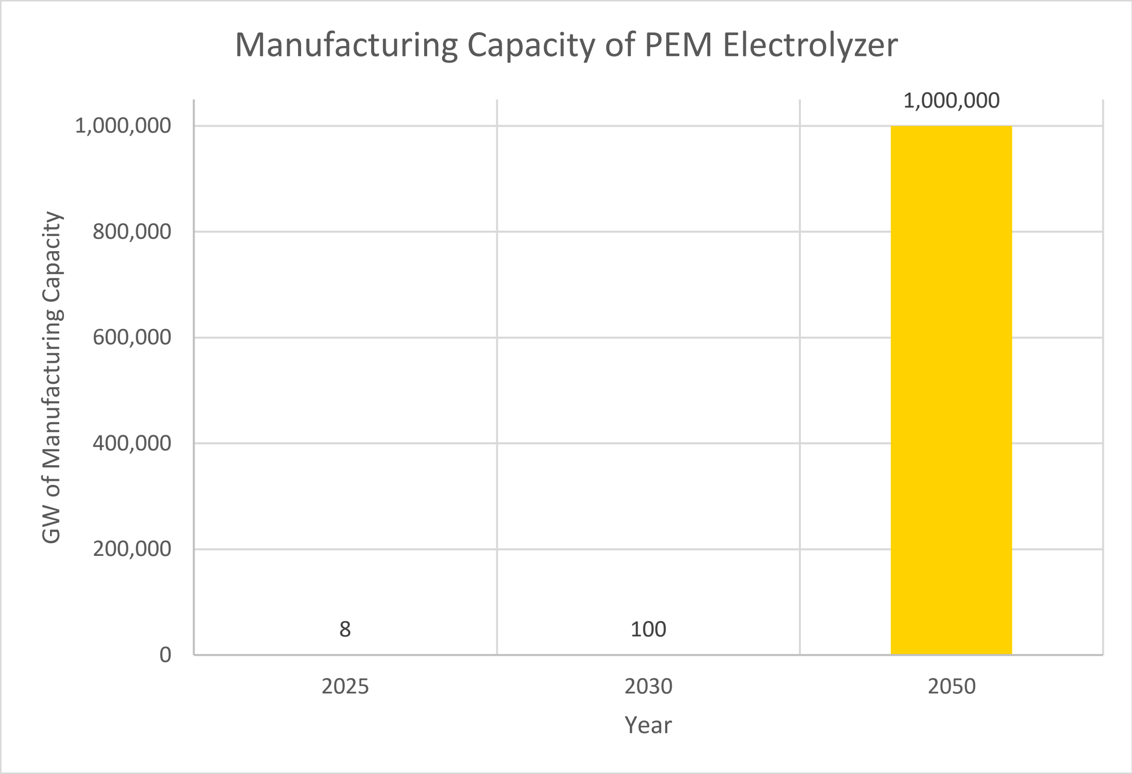
4.2 ELECTROLYZER PRECIOUS METALS

In addition to the electrolyzer production not being able to support the demand from EPA's rule, the precious metals, especially iridium and platinum, needed to produce electrolyzers are a critical barrier to production.

PEM electrolysis is the most popular technology, and it uses iridium and platinum. According to an article published by the International Renewable Energy Agency (IRENA) https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021.pdf?la=en&hash

=40FA5B8AD7AB1666EECBDE30EF458C45EE5A0AA6, scarce materials can represent a barrier to electrolyzer cost and scale-up.

The current production of iridium and platinum for PEM electrolyzer will only support an estimated 7.5 GW of annual manufacturing capacity. However, IRENA estimates that demand will require an annual manufacturing requirement of 100 GW by 2030. IRENA also projects that 1 TW of installed capacity would be required in 2050. The graph below demonstrates these numbers if visual form and shows the impractical requirements for iridium and platinum if IRENA's forecasts are correct. However, even if IRENA's forecasts are close, it demonstrates a significant problem in the commodities market with meeting the needs of the electrolyzer market for green hydrogen.



The bottom line for electrolyzers is that the demand for them in the next two decades is exponential. However, the precious metals availability means meeting these goals are highly unlikely. Given these facts, EPA's assumption that hydrogen can be produced by electrolysis, in the quantities that will be required to by the rule, is flawed.

Attachment J

Analysis of Hydrogen in Combustion Turbine Electric Generating Units

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. Doug Campbell, FTB Energy Solutions, Inc.

August 3, 2023

Introduction

This paper provides technical commentary on the Environmental Protection Agency's (EPA's) proposed rule "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule." The proposed rule would require some fossil fuel-fired stationary combustion turbine electric generating units (EGUs) to use emission control measures that are based on highly efficient generating practices, hydrogen co-firing, and carbon capture and storage (CCS). [1]

Executive Summary

This document focuses on various aspects of hydrogen co-firing, including known demonstrations to date, status of hydrogen production and transportation, and numerous identified technology challenges. The EPA's stated objective is "each of the [New Source Performance Standards (NSPS)] and emission guidelines proposed here would ensure that EGUs reduce their [greenhouse gas (GHG)] emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable [Clean Air Act (CAA)] requirements and caselaw."

This paper only looks at the evaluation of the status of the technology as presented in "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document." [2] This paper does not evaluate the proposal's consideration of CCS for gas-fired units.

The following key findings were determined:

1) Approximately 176 MW of clean energy is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen. This is extremely inefficient and would result in the addition of a significant amount of electrical generation required to create the hydrogen fuel.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (approximately 45 MW) for 24 hours would require more than 200 trailer truckloads to be delivered and unloaded in that period. The amount of GHG emissions from the transportation of the fuel would be significant and would undercut any perceived benefit derived. (The LM6000 is one of the more common gas turbines in the generation fleet and has a full load rating at sea level standard conditions of 46.6 MW.)
3) Although hydrogen can be transported in specially built pipelines, there is not currently a sufficient piping network available, nor will there be in the foreseeable future.
4) A hydrogen production price of $0.5/kg or $1/kg, as referenced by EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of $5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

Background

For the purposes of the EPA's proposal, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," [1] affected gas units are categorized in Table 2 (Proposed Sales Thresholds for Subcategories of Combustion Turbine EGUs) of page 33322 of the proposed rules as either new gas combustion units or existing gas combustion units. New gas combustion units (i.e., those that commenced construction on or after May 23, 2023) would need to meet certain emissions limitations, clean hydrogen co-firing requirements, and/or CCS requirements. The compliance requirements for new gas units depends upon their capacity factor categorization as either baseload units (generally above 40% for simple cycle units or above 55% for natural gas combined cycle (NGCC)), intermediate load units (between 20% and 40% for simple cycle or 55% for NGCC), or low load units (less than or equal to 20%). For existing gas combustion units, large units with a nameplate capacity of greater than 300 MW and a capacity factor of greater than 50% would be required to meet either clean hydrogen co-firing requirements or CCS requirements.

The EPA has modelled its assumptions using the Integrated Planning Model (IPM) v6.21 model, [4] using assumptions of cost data, such as the National Energy Technology Laboratory (NETL), the International Energy Administration (IEA) Energy Outlook, and other industry reports. The classifications for this model are as defined in Table 2 on page 4 of the "Integrated Proposal Modeling and Updated Baseline Analysis." [5] It appears that the EPA has grouped multiple years in each run, with a total of four runs. Although selective output is presented in the reports, there does not appear to be sensitivity runs on the variables that would be considered most important, other than gas supply curves. Other variables might be just as important for modeling, such as demand, dry or wet hydropower years, or oil prices. This generally would be determined by a presentation of the statistical relevance of each factor. The EPA does say run time was a consideration in making these choices, but provides no insight as to the boundaries. Furthermore, there appears to be no consistency in batching the years run. All this is important because big swings in major variables can change dispatch significantly. By running sensitivities, risk exposure can be defined.

Analysis and Considerations

The information reviewed in this section is found in the EPA's document "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document," Docket ID No. EPA- HQ- OAR-2023-0072. [2] The EPA uses NETL cost data that is developed through a well-defined procedure described in NETL document "Quality Guidelines for Energy Systems Studies," [6] using Class 4 or Class 5 estimates. It is noted that these guidelines are consistent and widely accepted in cost comparisons of one technology to another, but they do not provide a comprehensive assessment of total project costs. As the owner is exposed to full project cost, for such a comprehensive assessment, a full project cost approach should be used, as referenced in the U.S. Energy Information Administration's (EIA) "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" report. [7] That approach better demonstrates the cost for specific projects. Further details on the analysis supporting this recommendation can be found in the accompanying comment paper, “Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy,” (Doug Campbell, August 3, 2023).

Hydrogen Production

The EPA document states that “most of the dedicated hydrogen currently produced in the U.S. (more than 95 percent) originates from natural gas using a process known as steam methane reforming.” The paper then goes on to discuss various other processes for hydrogen production that are at different stages in development. The target date for new and existing natural gas units of 30% co-firing with low-GHG hydrogen is 2032.

By the definition of low-GHG hydrogen, this energy would have to come from renewable energy resources, such as wind or solar. In reviewing estimated timelines for permitting, licensing, and construction of new zero-emitting nuclear generating facilities, such as small modular reactors, it is unlikely that this would be a viable option for hydrogen production in the timeframe required. When considering small modular reactors, it is noted that the process of mining and refining uranium ore requires large amounts of energy that generally come from CO_2 emitting resources.

The only technology that appears to be viable at scale in the time frame that would meet EPA’s low-GHG requirements is hydrogen produced by electrolysis. Electrolysis is a process that uses the power of electricity to split elements into compounds. In this process, electric current is passed between a cathode and an anode in water to release hydrogen and oxygen. Electrolysis is forecast to require between 48-53 kWh of electricity to produce one kilogram of hydrogen. [8] The energy required to produce enough hydrogen to fire one single LM6000 simple cycle gas turbine (46.6 MW gross) is calculated to be 176.5 MW or 3.8 times the output power. This calculation assumes a rating of 46.6 MW gross for the LM6000. Gross power is the total power generated by the unit including the power required to supply auxiliary equipment. Net power to the system is gross power minus auxiliary power.

Important to the EPA analysis is the cost of hydrogen. The second phase of the proposed regulation starts in 2032, and the EPA states in the notes of page 4 of the reference document [5] “delivered hydrogen price is assumed to be \$0.5/kg in years in which the second phase or third phase of the NSPS is active, and \$1/kg in all other years.” Cost studies that I have reviewed show that the most optimistic price being used today is about \$5/kg using electrolysis. The IEA Global Hydrogen Review 2022 [9] page 6 shows the cost range of clean hydrogen, even under an optimistic scenario, would still fall between \$1.3/kg and \$4.5/kg by 2030. This optimistic scenario assumes electrolyser projects currently under development are completed, manufacturing capacities are rapidly scaled up, and the costs of renewable energy continues to drop.

The lower end of that range would only be possible for regions with sufficient access to renewable energy to be competitive. A median price of \$2.9/kg, based on that IEA projection, could reflect a 40% reduction in the cost of low-GHG hydrogen, but would still be six times greater than the EPA’s modelled price. This is a major concern.

The EPA also notes on page 20 of the reference document that "for each kg of hydrogen produced through electrolysis, 9 kg of by-product oxygen are also produced and 9 kg of purified water are consumed." [2]. To create enough fuel to run a single LM6000 for 24 hours at 46.6 MW gross on 100% hydrogen, one would use 173,142 U.S. gallons of water per day just to make hydrogen. Any additional water requirements to run the unit would be added to this. In many regions of North America, water resources are at a premium now and would not be able to support these levels of low-GHG hydrogen production, so this provides another challenge to the hydrogen supply.

Use of Hydrogen in Combustion Turbines

It is recognized that combustion turbines have been burning by-product fuels containing hydrogen for decades. It is noted in the EPA documents that these applications are generally in the oil and gas sectors, as well as some developments with syngas firing for Integrated Gas Combined Cycle (IGCC) units. The discussion that is presented in the Technical Support Document references a long list of original equipment manufacturers' (OEMs') marketing material related to hydrogen co-firing from major manufactures such as GE, Siemens, and Mitsubishi. After reviewing several of these documents, my determination is that they are presented as either design goals for potential modification for existing units or development goals for futures offerings. Therefore, sales information that market blends beyond 20% have not been demonstrated in field tests with publicly available data. Until these units are proven commercial, they are not available to meet the EPA standards. The EPA is instead assuming that all the proposed test work will result in commercially-proven offerings.

The document also provides a list of proposed projects with specified hydrogen blends of 30% by volume and have projected completion dates between 2025 and 2029. Other projects are also described as "hydrogen ready," but there is no detailed information on what that means. As far as can be determined from literature searches, these projects are still in either the pre-Front-End Engineering Design (FEED) or FEED process of design and characterization and have not yet been determined to be economical or feasible. In some cases, permits have been obtained, but no firm operational dates are available. Based on publicly available information, these are only on paper or could be test runs in OEM research facilities. An example project that the EPA uses is the Los Angeles Department of Water and Power (LADWP) Scattergood Generating Station project. [1] An article in Hydrogen Insight [10] states that the actual status of this project is that the LADWP is to conduct a new or updated assessment and report the results to council in six months. Projects such as this, or technology tests, do not present an available option for meeting the EPA guidelines in the timelines specified.

An effort to determine the status of hydrogen firing was undertaken through searching publicly available information. Only two tests that were performed in North America were verified. The test with the most publicly available information was the New York Power Authority (NYPA) test on a GE LM6000 turbine in 2022. In their report, NYPA claimed to have burned from 5% to 44% blend by volume at its Brentwood facility. A search showed no publicly available data can be found to verify the duration of the test runs and the related performance. The Electric Power

Research Institute (EPRI) has a summary review of the test on its portal. [11] Information found suggests that the hydrogen was supplied via tube trailers, and due to the limited storage capacity of the trailers on the site, run times were relatively short. The mixing skid and associated piping had to be custom designed for this demonstration. (A mixing skid blends the hydrogen with the natural gas for the prescribed volumetric ratio.)

The second test was carried out at Georgia Power's Plant McDonough on a Mitsubishi M501 G gas turbine at 20% blend by volume. [12] Again, a specially designed fuel mixing skid was employed, and the test was limited by the amount of hydrogen that was available. A search showed no additional publicly available data on this test. In the literature, there is mention of test firing of lower blends in the 5% by volume range, but data are not available. The conclusion is that these very limited and short-duration hydrogen co-firing demonstrations do not provide justification to qualify as being adequately demonstrated today, and much work would be required to meet a 2032 goal on a commercial basis.

Transportation and Storage

As noted above, the gas unit that has the most publicly available information on hydrogen co-firing was the NYPA test fire of the LM6000 at Brentwood. With this information and known performance data of an LM6000, specifically heat rate, a calculation was done to determine what would be required to transport and store enough hydrogen for operation of a single simple cycle combustion turbine. In doing this calculation, a heat rate of 8,600 Btu/kWh LHV was used. This would be a rated performance for a new LM6000. A typical running unit could see a degradation of performance overtime of up to 10%. If that was the case, more hydrogen would be burned for the same output. It was assumed to be fired at the design rated full load of 46.6 MW at standard conditions. The EPA implies in its work that trucking is a cost-effective option up to 200 miles. One hydrogen tube trailer can contain 380 kg of hydrogen compressed to 2,600 pounds per square inch gauge (psig). [13] Using calculations from the LM6000 mentioned above, nine tube trailers would be required for each hour of full load operation, or more than 200 trucks a day for a single 46.6 MW machine. The logistics of moving this many trucks would be unmanageable. The other option is to store on site the equivalent amount of hydrogen. Although not sized here, this would be a significant sized high-pressured tank.

While the EPA's support document states that there are about 1,600 miles of dedicated hydrogen pipeline services that exist, it is very user-specific, transporting hydrogen between oil, gas, and chemical process facilities. [14] This is compared to the about 3 million miles of natural gas pipeline installed. In the discussion section on transportation and storage, the EPA states that analysts "assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required." In doing literature research on the subject, very little definitive data were found. Some researchers say this number could be 5%-15%. [15] The IEA Global Hydrogen Review 2022 makes it clear that that upper bound of 20% hydrogen blend in pipelines without significant infrastructure changes is limited to certain distribution networks and would still require some upgrading. For natural gas transmission networks, the IEA notes that research indicates levels of only 5-10% of hydrogen blending is feasible without significant upgrades.

Another option could be a dedicated hydrogen pipeline. It could be designed to move approximately 88% of the equivalent energy of a natural gas pipeline in the same diameter pipe. [15] To do this, additional compression would be required. The construction of a new pipeline would also face all the challenges, costs, and timelines related to permitting, design, and construction. It is noted that due to the molecular weight of hydrogen, compressors need to operate at three times the speed of natural gas compressors. This requires specialized equipment and more energy to compress the gas.

If existing gas lines are to be used for hydrogen blends, then consideration needs to be given to all users. This often includes gas distribution companies that provide gas to residential and commercial services. Various studies are being carried out in Europe on how much hydrogen could be safely blended for this use, and 1% to 5% is the most recognized range of blends identified. Since the EPA's target date for 30% blending is 2032, we can rule out this option.

Conclusions

After reviewing the EPA technical document on hydrogen development, I can make several conclusions. One of the most important is the document's assertion that there is available pipeline capacity in the United States to meet the EPA requirements. This is not accurate. Although there is much talk about blending hydrogen into the natural gas transmission and distribution system, an amount of between 1% and 5% is likely all that is practical without major changes to end use equipment. This does not meet an EPA 30% blend target in 2032. The EPA proposes trucking on tube trailers for transport. As the LM6000 example shows, the logistics of moving this many trucks are not feasible. That would only leave on-site storage as an option, which the EPA does not adequately assess or account for in its support document.

The EPA's technical document reviewed the technical readiness level of the various turbine options. Although there is a lot of marketing or forecast development of machines that will run at 30% blends, they are neither demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA requirements.

As mentioned in the production section discussion, the EPA's targeted price for low-GHG hydrogen of $0.5/kg used in the modelling is not a reasonable assumption for the early years of compliance requirements.

To summarize:

1) Approximately 176 MW of renewable electricity is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (46.6 MW) for 24 hours would require more than 200 tube trailer truckloads to be delivered and unloaded daily.
3) Although hydrogen can be transported in specially built pipelines, there will not be a sufficient network available in the foreseeable future.

4) A hydrogen production price of \$0.5/kilogram (kg) or \$1/kg, as referenced by the EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of \$5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

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About the Author

Mr. Doug Campbell, FTB Energy Solutions, Inc.

Mr. Doug Campbell is a professional engineer with demonstrated managerial ability including planning, financial control, contract management, staff supervision and reporting. Over a 48-year career, Mr. Campbell has developed a wide range of technical skills associated with the design construction and start-up of new generation and the operation and maintenance of existing generation facilities. He has held positions as Manager of Hydro, Manager of a Multi-unit Steam Plant and Combustion Turbine operation, as well as Director of Generation Services in a vertically-integrated utility. As a Senior Technical Advisor, Mr. Campbell contributed to various engineering problems, such as recent studies on inspection and evaluation of fitness for service for high pressure equipment and various pressure retaining component parts. His involvement as an independent contractor has been in providing expert advice on new and developing technologies to support the transformation of the electrical grid. Current work includes providing insights in these developments, especially as related to a low carbon world. Mr. Campbell completed a Master of Science in Energy from Heriot-Watt University in 2018 and a Master of Applied Economics from Saint Mary's University in 2022, which has allowed him to obtain additional skills to evaluate technology and to comment on the strategic outcomes of their application.

Reference calculation and terminology to be aware of in Hydrogen Natural Gas Comparisons

Doug Campbell

July 11, 2023

Conversion Factors

Definition of and calculation of decatherms for natural gas consumption and billing

Explanation as found in Wikipedia, often useful never cited.

The **therm** (symbol, **thm**) is a non-SI unit of heat energy equal to 100,000 British thermal units (BTU),[1] and approximately 105 megajoules, 29 kilowatt-hours, 25200 kilocalories and 25.2 thermies. One therm is the energy content of approximately 100 cubic feet (2.83 cubic metres) of natural gas at standard temperature and pressure. However, the BTU is not standardised worldwide, with slightly different values in the EU, UK, and USA, meaning that the energy content of the therm also varies by territory.

Natural gas meters measure volume and not energy content, and given that the energy density varies with the mix of hydrocarbons in the natural gas, a 'therm factor' is used by natural gas companies to convert the volume of gas used to its heat equivalent, usually being expressed in units of 'therms per CCF' (CCF is an abbreviation for 100 cubic feet). Higher than average concentration of ethane, propane or butane will increase the therm factor and the inclusion of non-flammable impurities, such as carbon dioxide or nitrogen will reduce it. The Wobbe Index of a fuel gas is also sometimes used to quantify the amount of heat per unit volume burnt.

Definitions

- Therm (EC) ≡ 100000 BTU_{ISO}[2]

  = 105506000 joules
  ≈ 29.3072 kWh
  The therm (EC) is often used by engineers in the US.

- Therm (US) ≡ 100000 $BTU_{59\,°F}$[3]

  = 105480400 joules
  ≈ 29.3001111111111 kWh.

- Therm (UK) ≡ 105505585.257348 joules[4]

  ≡ 29.3071070159300 kWh

Decatherm

A **decatherm** or **dekatherm**[5] (dth or Dth) is 10 therms, which is 1,000,000 British thermal units or 1.055 GJ.[6][7] It is a combination of the prefix for 10 (deca, often with the US spelling "deka") and the energy unit therm. There is some ambiguity, as "decatherm" uses the prefix "d" to mean 10, where in metric the prefix "d" means "deci" or one-tenth, and the prefix "da" means "deca", or 10, though decatherm may use a capital "D". The energy content of 1,000 cubic feet (28 m^3) natural gas measured at standard conditions is approximately equal to one dekatherm.

This unit of energy is used primarily to measure natural gas. Natural gas is a mixture of gases containing approximately 80% methane (CH_4) and its heating value varies from about or 10.1 to 11.4 kilowatt-hours per cubic metre (975 to 1,100 Btu/cu ft), depending on the mix of different gases in the gas stream. The volume of natural gas with heating value of one dekatherm is about 910 to 1,026 cubic feet (25.8 to 29.1 m^3). Noncombustible carbon dioxide (CO_2) lowers the heating value of natural gas. Heavier hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}) increase its heating value. Since customers who buy natural gas are actually buying heat, gas distribution companies who bill by volume routinely adjust their rates to compensate for this.[8]

The company Texas Eastern Transmission Corporation, a natural gas pipeline company, started to use the unit dekatherm in about 1972. To simplify billing, Texas Eastern staff members coined the term dekatherm and proposed using calorimeters to measure and bill gas delivered to customers in dekatherms.[9] This would eliminate the constant calculation of rate adjustments to dollar per 1000 cubic feet rates in order to assure that all customers received the same amount of heat per dollar. A settlement agreement reflecting the new billing procedure and settlement rates was filed in 1973. The Federal Power Commission issued an order approving the settlement agreement and the new tariff using dekatherms later that year,[10] Other gas distribution companies also began to use this process.[11]

In spite of the need for adjustments, many companies continue to use cubic feet rather than dekatherms to measure and bill natural gas.[12][13]

Referenced from " Kyle's Converter"

https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)

Unit Descriptions	
1 Cubic Foot of Natural Gas: 1000 BTU_{IT}	1 Dekatherm (US): Roughly energy equivalent of a thousand cubic feet of natural gas (MCF). Equivalent to 1 000 000 BTU; dekatherm (US) based on the $BTU_{59°F}$ popular in USA. 1 Dekatherm (Dth US) = 1 054 804 000 joules (J).

Link to Your Exact Conversion
https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)#400000

Conversions Table	
1 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.001	70 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.07
2 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.002	80 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.08
3 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.003	90 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.09
4 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.004	100 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.1
5 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.005	200 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.2
6 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.006	300 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.3001
7 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.007	400 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.4001
8 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.008	500 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.5001
9 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.009	600 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.6001
10 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.01	800 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.8002
20 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.02	900 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.9002
30 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.03	1,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1.0002
40 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.04	10,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 10.0024
50 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.05	100,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 100.0239
60 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.06	1,000,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1000.2388

Calculation:

# of million cubic feet * Btu energy = dekatherms

Important things to be aware of:

Carbon dioxide emission coefficients in fuel is stated in:

lbs CO2 per million btu of fuel (Ex. Natural gas 116.65 of fuel burned)

EPA emission limits are stated in CO_2 /MWh -gross:

Example is 1,150 lb CO_2/MWh -Gross

Gas turbine efficiency calculations utilize Low Heating Values.

This is important to be aware of as conventional boilers following ASME heat rate calculations determine heat rate by HHV high heating value. Generally, units are dispatched on the HHV calculation.

Rule of thumb is to HHV = 1.11 * LHV.

Hydrogen Natural gas Comparisons:

Always be aware if you are talking by volume or by mass. Generally speaking, when suppliers are talking blending, they will be speaking in terms of % by volume.

6 Important properties of Natural Gas and Hydrogen

The following is extracted from Power Engineers:

https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas

Chemical Formula:	Hydrogen: H_2 Natural gas (methane): CH_4
Molecular Weight:	Hydrogen: 2 Natural gas (methane): 16
Flammability Limit	Hydrogen :4%/75% Natural Gas: 7%/20%
Flame Speed	Hydrogen :200-300cm/sec Natural Gas: 30-40cm/sec
Adiabatic Flame Temperature	Hydrogen :4000F Natural Gas: 3565 F
Heating value LHV (BTU/Lb)	Hydrogen: 51623Btu/lb. Natural Gas :(methane) 21518 Btu/lb
Volumetric LHV (Btu/ft^3)	Hydrogen: 266 Btu/ft^3 Natural Gas (methane): 881Btu/ft^3

Note: Absolute numbers vary depending on refence used. This reflects different gas quality from various processors.

Calculation for LM 6000 Gas Turbine with associated Reference Material

Doug Campbell

July 11, 2023

Calculation of LM 6000 fuel requirements:

Heat rate LHV = 8600 Btu/kwh

Heating Value Natural Gas LHV = 21,500 Btu/Lb (CH_4)

Fuel Burned:

8,600/21500 = .4Lb/kwh   Btu/kwh /btu/Lb = Lb /kwh

.4Lb/kwh * 1000 kwh /MWh = 400 Lb/MWh

1 MWh = 3.412 mmBtu

400Lb/MWh * 1Mwh/3.412 = 117 Lb/mmBtu

21,500 Btu/ln * 400 Lb/MWh = 8.6 * 10^6 Btu/MWh

Co_2 emissions = 116.65 LbCO_2/MBtu

CO_2 = 116.65 * 8.6 = 1003.19 Lb/MWh

LM 6000 full load meets CO_2 limit.

Full Load Calculation:

Fuel burned = 400 Lb/MWh

Full load = 46.6MW

Fuel burned: 400 * 46.6 = 18,600 Lb /hr

Btu input:

18,600 Lb/Hr * 21,500 Btu/lb.= 400.76 MMBtu/Hr.

Calculate number of tube trailers required 380 Kg trailers.

Hydrogen = 51,591Btu/Lb

One hour use = 400.76 MM Btu/51591 Btu/Lb = 7,780 Lb/hr = 3530.9 Kg/hr

Therefore 9 .29 tube trailers per hour required at full load.

Volume calculation:

NG = 964 Btu/ft^3

H_2 = 290 Btu/ft^3

Hydrogen = 400.76 mmBtu/hr * 1ft^3/290 Btu = 1.38 * 10^6 ft^3/hr

Natural Gas = 400.76mmbtu * 1ft^3 / 964 Btu = .41 * 10^6 ft^3/hr

When sizing pipe it is important to maintain the maximum allowable velocity in the pipe. We can see that velocities will increase greatly with hydrogen vs. natural gas. Therefore, in order to meet full load either pipelines need to be made larger or the pressure to maintain energy density needs to increased. A detailed engineering study by a piping engineer would be required to optimize the solution.

2.1 Low Density and Energy Content

Hydrogen has the lowest mass density of any substance in the universe, with an atomic weight of only 2.0. It is about eight times lighter than methane (CH_4) [1]. Because of this, there is a common misconception that hydrogen is a superior fuel to natural gas because of its larger heating value (141.86 MJ/kg for H_2 versus 55.53 MJ/kg for pure methane). However, this is due to the fact that hydrogen is *very light* compared to natural gas, not because it actually contains that much energy on a volume basis compared to natural gas. On a molecular basis, there is more energy contained within four C-H bonds compared to one single H-H bond. Also, gas turbine combustors are of fixed volume and designed to work at specific operating pressures with little room for deviation. Therefore, the amount of hydrogen that can be used in a particular gas turbine is limited by volume. Indeed, looking at the energy content on a per-unit-volume or mole basis reveals that natural gas has more than three times the energy density of hydrogen by volume (10,050 kJ/m^3 H_2 versus 32,560 kJ/m^3 CH_4) [1]. Thus, to accommodate hydrogen fuel, hydrogen gas turbines will either need to be larger, incorporate higher max pressures to reduce gas volumes, or both to compete with natural gas turbines. This means that, to achieve similar performance/emissions ratings to their natural gas counterparts, hydrogen turbines may be more costly to produce.

How do you calculate specific fuel consumption of gas turbine?

A simple-cycle gas turbine used for power generation has a thermal efficiency of about 34 percent. Since 1 kwh is theoretically equivalent to 3,415 Btu,the simple-cycle gas turbine has a fuel connsumption of:3,415 / 0.34 = about 10,000 Btu/kwh.

Given the heating value (i.e, heat of combustion) of a fuel, we can easily calculate thesimple-cycle gas turbine fuel usage.

For example, natural gas has a net heating value of about 21,500 Btu/pound.Thus, the natural gas consumption in a simple-cycle gas turbine would be:10,000 / 21,500 = 0.47 pounds/kwh = 0.21 kg/kwh.

As another example, a typical diesel oil has a net heating value of 130,000 Btu/gallon.Thus, the diesel oil consumption in a simple-cycle gas turbine would be:10,000 / 130,000 = 0.077 gallon/kwh.

(The gallon used just above is the U.S. gallon rather than the Imperial gallon)A combined-cycle gas turbine will have a higher thermal efficiency and, hence, lower fuel consumptions.

	LM6000 PC	LM6000 PG	LM6000 PF	LM6000 PF+
Net output (MW)	46.6/51.1*	56/57.2*	44.7/50*	53.9/57.1*
Net heat rate (Btu/kWh, LHV)	8533	8728	8248	8357
Net heat rate (kJ/kWh, LHV)	9002	9208	8702	8817
Net efficiency (%, LHV)	40%	39.1%	41.4%	40.8%
Ramp rate (MW/minute)	30	30	30	30
Startup time (cold iron) (min.)	5	5	5	5
GT Min. Turn Down Load (%)	25%	25%	50%	50%

LM6000 gas turbines can start up in 5 minutes

*MW output without SPRINT/with SPRINT

NOTE: All ratings are based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

Fuels - Higher and Lower Calorific Values

Higher and lower calorific values (heating values) for fuels like coke, oil, wood, hydrogen and others.

Energy content or calorific value is the same as **the heat of combustion**, and can be calculated from thermodynamical values, or measured in a suitable apparatus:

A known amount of the fuel is burned at constant pressure and under standard conditions (0°C and 1 bar) and the heat released is captured in a known mass of water in a calorimeter. If the initial and final temperatures of the water is measured, the energy released can be calculated using the equation

$$H = \Delta T \, mC_p$$

where H = heat energy absorbed (in J), ΔT = change in temperature (in °C), m = mass of water (in g), and C_p = specific heat capacity (4.18 J/g°C for water). The resulting energy value divided by grams of fuel burned gives the energy content (in J/g).

The combustion process generates water vapor and certain techniques may be used to recover the quantity of heat contained in this water vapor by condensing it.

- **Higher Calorific Value** (= Gross Calorific Value - GCV = Higher Heating Value - HHV) - the water of combustion is entirely condensed and the heat contained in the water vapor is recovered
- **Lower Calorific Value** (= Net Calorific Value - NCV = Lower Heating Value - LHV) - the products of combustion contains the water vapor and the heat in the water vapor is not recovered

The table below gives the gross and net heating value of fossil fuels as well as some alternative biobased fuels.

See also Heat of combustion, Fossil and Alternative Fuels - Energy Content and Combustion of Fuels - Carbon Dioxide Emission

Fuel	Density @0°C/32°F, 1 bar		Higher Heating Value (HHV) (Gross Calorific Value - GCV)					Lower Heating Value (LHV) (Net Calorific Value - NCV)				
Gaseous fuels	[kg/m^3]	[g/ft^3]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m^3]	[Btu/ft^3]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m^3]	[Btu/ft^3]
Acetylene	1.097	31.1	13.9	49.9	21453	54.7	1468					
Ammonia				22.5	9690							
Hydrogen	0.090	2.55	39.4	141.7	60920	12.7	341	33.3	120.0	51591	10.8	290
Methane	0.716	20.3	15.4	55.5	23874	39.8	1069	13.9	50.0	21496	35.8	964
Natural gas (US market)*	0.777	22.0	14.5	52.2	22446	40.6	1090	13.1	47.1	20262	36.6	983
Town gas						18.0	483					
	@15°C/60°F											
Liquid fuels	[kg/l]	[kg/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]
Acetone	0.787	2.979	8.83	31.8	13671	25.0	89792	8.22	29.6	12726	23.3	83580
Butane	0.601	3.065	13.64	49.1	21109	29.5	105875	12.58	45.3	19475	27.2	97681
Butanol	0.810		10.36	37.3	16036	30.2	108359	9.56	34.4	14789	27.9	99934
Diesel fuel*	0.846	3.202	12.67	45.6	19604	38.6	138412	11.83	42.6	18315	36.0	129306
Dimethyl ether (DME)	0.665	2.518	8.81	31.7	13629	21.1	75655	8.03	28.9	12425	19.2	68973
Ethane	0.572	2.165	14.42	51.9	22313	29.7	106513	13.28	47.8	20550	27.3	98098
Ethanol (100%)	0.789	2.987	8.25	29.7	12769	23.4	84076	7.42	26.7	11479	21.1	75583
Diethyl ether (ether)	0.716	2.710	11.94	43.0	18487	30.8	110464					
Gasoline (petrol)*	0.737	2.790	12.89	46.4	19948	34.2	122694	12.06	43.4	18659	32.0	114761

Gas oil (heating oil)*	0.84	3.180	11.95	43.0	18495	36.1	129654	11.89	42.8	18401	36.0	128991
Glycerin	1.263	4.781	5.28	19.0	8169	24.0	86098					
Heavy fuel oil*	0.98	3.710	11.61	41.8	17971	41.0	146974	10.83	39.0	16767	38.2	137129
Kerosene*	0.821	3.108	12.83	46.2	19862	37.9	126663	11.94	43.0	18487	35.3	126663
Light fuel oil*	0.96	3.634	12.22	44.0	18917	42.2	151552	11.28	40.6	17455	39.0	139841
LNG*	0.428	1.621	15.33	55.2	23732	23.6	84810	13.50	48.6	20894	20.8	74670
LPG*	0.537	2.033	13.69	49.3	21195	26.5	94986	12.64	45.5	19561	24.4	87664
Marine gas oil*	0.855	3.237	12.75	45.9	19733	39.2	140804	11.89	42.8	18401	36.6	131295
Methanol	0.791	2.994	6.39	23.0	9888	18.2	65274	5.54	19.9	8568	15.8	56562
Methyl ester (biodiesel)	0.888	3.361	11.17	40.2	17283	35.7	128062	10.42	37.5	16122	33.3	119460
MTBE	0.743	2.811	10.56	38.0	16337	28.2	101244	9.75	35.1	15090	26.1	93517
Oils vegetable (biodiesel)*	0.92	3.483	11.25	40.5	17412	37.3	133684	10.50	37.8	16251	34.8	124772
Paraffin (wax)*	0.90	3.407	12.78	46.0	19776	41.4	148538	11.53	41.5	17842	37.4	134007
Pentane	0.63	2.385	13.50	48.6	20894	30.6	109854	12.60	45.4	19497	28.6	102507
Petroleum naphtha*	0.725	2.745	13.36	48.1	20679	34.9	125145	12.47	44.9	19303	32.6	116819
Propane	0.498	1.885	13.99	50.4	21647	25.1	89963	12.88	46.4	19927	23.1	82816
Residual oil*	0.991	3.752				41.8	150072	10.97	39.5	16982	39.2	140470
Tar*			10.00	36.0	15477							
Turpentine	0.865	3.274	12.22	44.0	18917	38.1	136555					
Solid fuels*			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**		
Anthracite coal			9.06	32.6	14015							
Bituminous coal			8.39	30.2	12984			8.06	29.0	12468		
Carbon			9.11	32.8	14101							
Charcoal			8.22	29.6	12726			7.89	28.4	12210		
Coke			7.22	26.0	11178							
Lignite (brown coal)			3.89	14.0	6019							
Peat			4.72	17.0	7309							
Petroleum coke			8.69	31.3	13457			8.19	29.5	12683		
Semi anthracite			8.19	29.5	12683							
Sub-Bituminous coal			6.78	24.4	10490							
Sulfur (s)			2.56	9.2	3955			2.55	9.2	3939		
Wood (dry)	0.701		4.50	16.2	6965			4.28	15.4	6621		

* Fuels which consist of a mixture of several different compounds may vary in quality between seasons and markets. The given values are for fuels with the given density. The variation in quality may give heating values within a range 5 -10% higher and lower than the given value. Also the solid fuels will have a similar quality variation for the different classes of fuel.

- 1 Btu(IT)/lb = 2.3278 MJ/t = 2327.8 J/kg = 0.55598 kcal/kg = 0.000646 kWh/kg
- 1 kcal/kg = 1 cal/g = 4.1868 MJ/t = 4186.8 J/kg = 1.8 Btu(IT)/lb = 0.001162 kWh/kg
- 1 MJ/kg = 1000 J/g = 1 GJ/t = 238.85 kcal/kg = 429.9 Btu(IT)/lb = 0.2778 kWh/kg
- 1 kWh/kg = 1547.7 Btu(IT)/lb = 3.597 GJ/t = 3597.1 kJ/kg = 860.421 kcal/kg

- 1 Btu(IT)/ft^3 = 0.1337 Btu(IT)/gal(US liq) = 0.03531 Btu(IT)/l = 8.89915 kcal/m^3 = 3.7259x10^4 J/m^3
- 1 Btu(IT)/gal(US liq) = 0.2642 Btu(IT)/l = 7.4805 Btu(IT)/ft^3 = 66.6148 kcal/m^3 = 2.7872x10^5 J/m^3
- 1 MJ/m^3 = 26.839 Btu(IT)/ft^3 = 3.5879 Btu(IT)/gal(US liq) = 0.94782 Btu(IT)/l = 239.01 kcal/m^3
- 1 kcal/m^3 = 0.11237 Btu(IT)/ft^3 = 0.01501 Btu(IT)/gal(US liq) = 0.003966 Btu(IT)/l = 4186.8 J/m^3

‹ ENVIRONMENT

Carbon Dioxide Emissions Coefficients

Release Date: October 5, 2022 | XLS | METHODOLOGY

Carbon Dioxide Emissions Coefficients by Fuel

Carbon Dioxide (CO_2) Factors:	Pounds CO_2 Per Unit of Volume or Mass	Kilograms CO_2 Per Unit of Volume or Mass	Pounds CO_2 Per Million Btu	Kilograms CO_2 Per Million Btu
For homes and businesses				
Propane	12.68 gallon	5.75 gallon	138.63	62.88
Diesel and Home Heating Fuel (Distillate Fuel Oil)	22.45 gallon	10.19 gallon	163.45	74.14
Kerosene	21.78 gallon	9.88 gallon	161.35	73.19
Coal (All types)	3,876.61 short ton	1,758.40 short ton	211.87	96.10
Natural Gas	120.96 thousand cubic feet	54.87 thousand cubic feet	116.65	52.91
Finished Motor Gasoline[a]	17.86 gallon	8.10 gallon	148.47	67.34
Motor Gasoline	19.37 gallon	8.78 gallon	155.77	70.66
Residual Heating Fuel (Businesses only)	24.78 gallon	11.24 gallon	165.55	75.09
Other transportation fuels				
Jet Fuel	21.50 gallon	9.75 gallon	159.25	72.23
Aviation Gas	18.33 gallon	8.32 gallon	152.54	69.19
Industrial fuels and others not listed above				
Petroleum coke	32.86 gallon	14.90 gallon	225.13	102.12
Nonfuel uses				
Asphalt and Road Oil	26.25 gallon	11.91 gallon	166.12	75.35
Lubricants	23.58 gallon	10.70 gallon	163.29	74.07
Naphthas for Petrochemical Feedstock Use	18.74 gallon	8.50 gallon	149.95	68.02
Other Oils for Petrochemical Feedstock Use	22.61 gallon	10.26 gallon	163.05	73.96
Special Naphthas (solvents)	19.94 gallon	9.04 gallon	159.57	72.38
Waxes	21.10 gallon	9.57 gallon	160.06	72.60
Coals by type				
Anthracite	5,715.11 short ton	2,592.33 short ton	228.60	103.69
Bituminous	4,933.59 short ton	2,237.84 short ton	205.57	93.24
Subbituminous	3,747.36 short ton	1,699.78 short ton	214.13	97.13
Lignite	2,813.18 short ton	1,276.04 short ton	216.40	98.16
Coke	7,196.24 short ton	3,264.17 short ton	250.59	113.67
Other fuels				
Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97

Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97
Waste oil[b]	22.51 gallon	10.21 gallon	163.14	74.00

Data source: arbon factors provided by the U.S. Environmental Protection Agency, Inventory of *U.S. Greenhouse Gas Emissions and Sinks*: 1990-2020, Tables A-22, A-27, A-34, and A-230

[a]Includes fuel ethanol blended into motor gasoline. The fuel ethanol component of finished motor gasoline is treated as nonemissive. See methodology documentation for further details on calculations.

[b]Carbon factors for municipal solid waste, tire-derived fuel, and waste oil are provided by the U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Factor Hub*

[c]The carbon factor for municipal solid waste has been adjusted to apply both to biogenic and non-biogenic waste

Note: To convert to carbon equivalents multiply by 12/44.

Coefficients may vary slightly with estimation method and across time.

Coefficients are based on data from 2020. EIA uses these coefficients for estimating 2021, and more recent, energy-related CO_2 emissions.

Voluntary Reporting Program emissions factors (discontinued)

Attachment K

Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on the Generation Alternative of Fuel Switching to Natural Gas

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

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August 3, 2023

Introduction

The EPA's proposed greenhouse gas (GHG) emissions regulations for existing coal-fired electric generating units (EGUs) ("proposed rules")[1] includes a determination that natural gas co-firing is a "best system of emission reduction" (BSER) for certain coal-fired EGUs. In support of this determination, the EPA includes in its regulatory docket a document entitled "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Steam EGU TSD).[2] Section 3.3 of that Steam EGU TSD, titled "Evaluation of Natural Gas Co-firing as BSER for Existing Coal-Fired EGUs," contains information about co-firing or converting coal-fired steam generating units to natural gas. Many of the assumptions in that section cannot be generalized to fit the fleet of generating units in the United States. Those deficiencies are addressed in the paragraphs below.

The EPA cites public reports, such as the Energy Information Administration (EIA) 2020 report entitled "More than 100 coal-fired plants have been replaced or converted to natural gas since 2011,"[3] to suggest that conversion to natural gas is a common occurrence and widely available to most coal plants. That is a misleading generalization that is unsupported by facts and experience. As the title of the EIA report indicates, 100 is the total number of units that have converted to natural gas, as well as those that were replaced altogether with gas generation. Indeed, the EIA report states, "At the end of 2010, 316.8 gigawatts (GW) of coal-fired capacity existed in the United States, but by the end of 2019, 49.2 GW of that amount was retired, 14.3 GW had the boiler converted to burn natural gas, and 15.3 GW was replaced with natural gas combined cycle." From those numbers, we see that 15.3 of those GW were replacement rather than fuel switching with the coal-fired boilers. Furthermore, these GWs together are 40% less than the amount of GWs that were retired, presumably because switching them or replacing them with gas was infeasible, uneconomical, or both. The report further states: "Coal-fired plants in the eastern half of the country have been good candidates for conversion because they tend to be smaller-capacity units and are mostly over 50 years old."[4]

The following graphic from the EIA shows that the majority of retired or repurposed coal-fired units were either retired outright or replaced entirely by a natural gas combined cycle unit, and demonstrates how small the percentage is of actual conversions of the coal-fired boilers to natural gas.[5]

[1] "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" (Docket EPA-HQ-OAR-2023-0072)

[2] "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Docket EPA-HQ-OAR-2023-0072)

[3] https://www.eia.gov/todayinenergy/detail.php?id=44636

[4] https://www.power-eng.com/emissions/coal-to-gas-plant-conversions-in-the-u-s/#gref

[5] https://www.eia.gov/todayinenergy/detail.php?id=44636

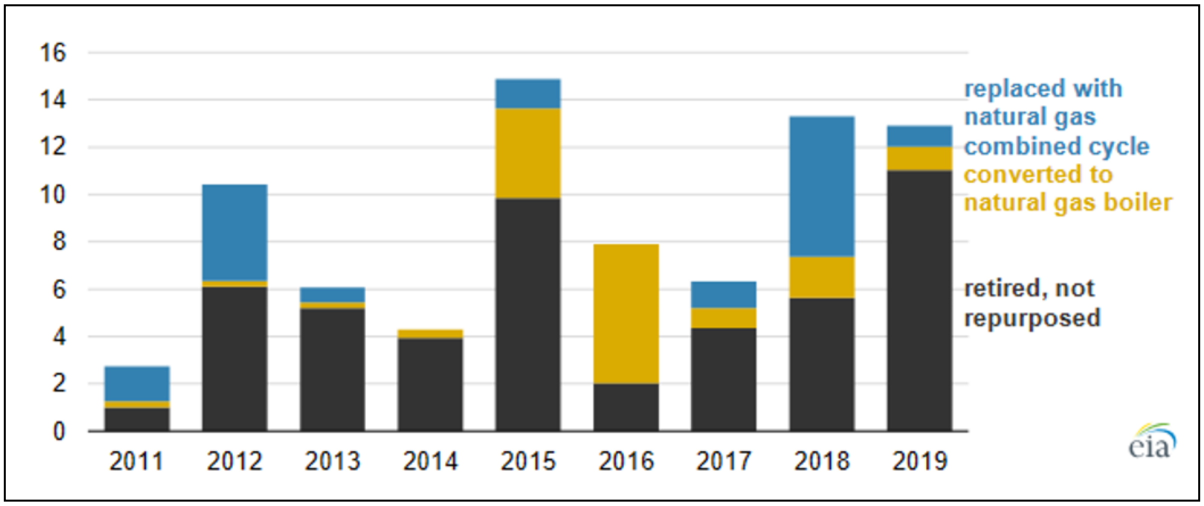

Figure 1: U.S. coal-fired capacity retired or repurposed to natural gas by conversion type (2011-2019) gigawatts (Source: EIA)

With that note of caution, let us examine the reasons why converting coal plants to natural gas is often not a practical option.

The Sargent & Lundy report entitled "Natural Gas Co-Firing Memo" (Project No. 13527-002 March 2023),[6] which is referenced by the EPA, provides a general description of co-firing natural gas in a coal boiler, including for ignition/warm-up. Most coal boilers require an ignition fuel to be utilized to ignite the coal on startup. If natural gas is available, it is one of the easiest ignition fuels to use, but using natural gas for ignition is not the same as co-firing with natural gas. In fact, it is common practice to shut down the natural gas igniters once the flame is established, so co-firing during normal operation is not as common a practice as the report would suggest.

However, the EPA inappropriately extrapolates that common practice of using natural gas in a limited way for startup to justify its claims that switching to natural gas or co-firing at levels required in its proposed rules are technically feasible. In its Steam EGU TSD, EPA states that 249 of 565 coal-fired units reported using natural gas "as a fuel **or startup source.**" From this, the EPA concludes – without basis – that higher levels of co-firing are "immediately available" at some coal units, based only on speculative discussion that some of those EGUs may have the ability to co-fire at higher levels and may be able to do so for significant periods of time.[7]

Several factors contribute to the practice of only using small amounts of natural gas for ignition fuel, including limitations related to the supply of natural gas, quantity available, and operational aspects of the boiler. These issues are discussed in further detail in this document. As the relatively low number of natural gas boiler conversions in the EIA data above indicates,

[6] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available at Docket ID EPA-HQ-OAR-2023-0072.

[7] "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Docket EPA-HQ-OAR-2023-0072)

however, the choice to switch to natural gas as the primary fuel, or to cofire significant quantities of natural gas for the boiler, is often neither feasible nor economical.

Finally, it is clear that significant levels of natural gas co-firing at existing coal units will have an impact on generating capacity of those units. The Sargent & Lundy report states that: "If steam temperatures are reduced, this lowers generator output and increases all heat rates." This will have a large impact on utility decisions with the current need to retain dispatchable capabilities in the fleet. This is in direct conflict with the EPA's assumptions in its March 2023 Integrated Planning Model assumptions (Table 5-18 Cost and Performance Assumptions for Coal-to-Gas Retrofits in v6 on page 5-23) where the EPA states that there will be no capacity loss from coal to gas conversion.[8]

Availability of Natural Gas During Periods of Inclement Weather and High Demand

The EPA has proposed that one option for cutting greenhouse gas emissions from coal-fired power stations is to utilize natural gas co-firing to reduce the carbon emissions per unit of heat input at the power station. While this may be possible in some cases, it is not feasible in many more other cases. For example, extreme winter weather has shown the risks of depending too much on natural gas for power generation. During winter storm Elliott, PJM Interconnection, the nation's largest system operator, experienced significant failures of natural gas fired power generators. During this event, the system was at severe risk of not being able to meet load. In the aftermath, PJM's analysis showed that "about 63% of all outages were natural gas" and that the failures were a result of the rapid onset of cold temperatures that "heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured for gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more-efficient gas-fired power generation units that require nominated supply and higher pipeline pressures to operate."[9]

Clearly, this event shows the risk of relying more heavily on natural gas as a fuel source, which may not be available to power generators when necessary. The supply of natural gas is already insufficient in the PJM region without the forced fuel switching and blending requirements that the EPA is proposing. Unless and until the EPA demonstrates that the existing gas infrastructure is able to meet current demand and the increased demand from mandated fuel switching, it is unreasonable to consider fuel switching an achievable option.

Inadequacy of Natural Gas Transmission and Distribution Infrastructure for Fuel Switching

The EPA proposal also assumes that natural gas is readily available for all coal fired power plants to begin fuel switching by 2030 to meet the regulatory mandate. However, this is not factually

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[8] Environmental Protection Agency. *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. March 2023. Available at: https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf

[9] *Winter Storm Elliott Frequently Asked Questions*, Issued by PJM, Accessed 7/19/23, Available at: https://www.pjm.com/-/media/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx

accurate. As detailed in the discussion that follows, the actual situation for each plant location would need to be studied to determine if a switch is feasible depending on natural gas pipelines proximity, capacity, and offtake limits, as well as feasibility, cost, and timeline for additional pipeline construction where needed.

Even under the most ideal circumstances, however, there are many coal-fired power stations that are not located adjacent to the necessary natural gas infrastructure required for fuel switching or blending, and would thus require additional pipeline infrastructure at a significant cost to the unit owner utility.

Provided below are figures and data from the EIA's Energy Atlas map related to coal-fired unit proximity to the nearest natural gas pipeline.[10] As evidenced by the examples further below, actual distances to pipelines with adequate capacity and offtake potential are often multiple times these distances and require tens or even hundreds of millions of dollars in capital costs alone. But the EIA map provides an illustrative example of the bare minimum distance for possible natural gas co-firing.

According to the EIA data, roughly 17% of coal-fired units nationwide are more than 10 miles from even the single nearest natural gas pipeline and nearly one-third are more than 5 miles.

Figure 2 overlays natural gas infrastructure and the location of coal-fired plants in the PJM area. Nearly half of the coal plants in the region are at least 2.5 miles, with a significant number of units in Eastern Pennsylvania 10 miles or further, from even the nearest natural gas pipeline that may potentially be available for fuel switching.

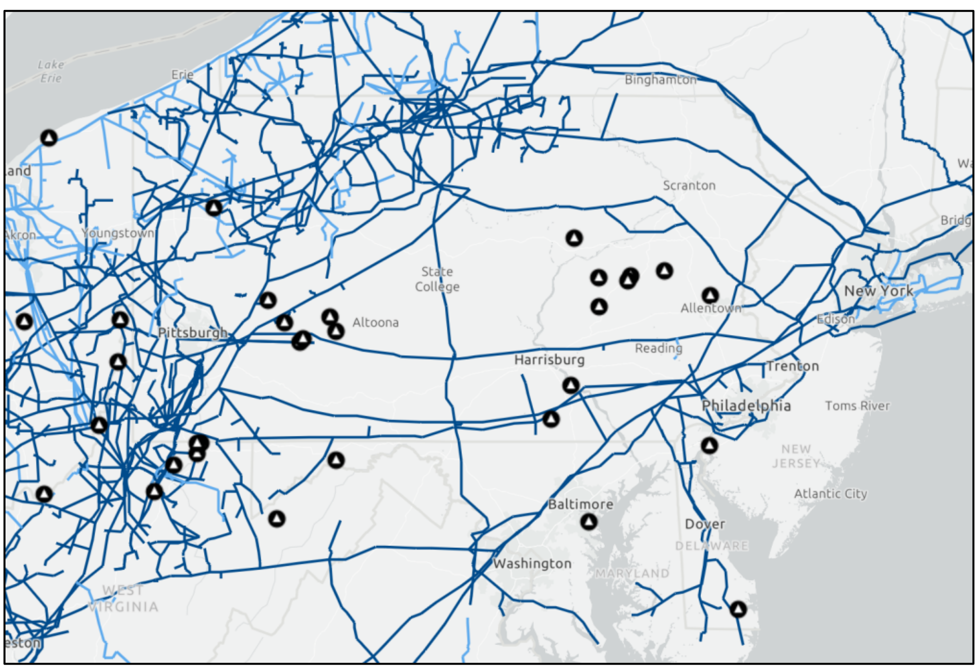

Figure 2. EIA data showing natural gas infrastructure and coal plants in the PJM region.

[10] EIA Energy Atlas Interactive Map, Accessed 7/19/2023, Available at: https://atlas.eia.gov/apps/eia::all-energy-infrastructure-and-resources/explore

This infrastructure mismatch is not limited to the mid-Atlantic or PJM region either. It's apparent, using the same map and data, that this absolute minimum possible distance is even greater in the central portion of the country (Figure 3), as well as the Upper Great Plains and Rocky Mountain Region (Figure 4). In Figure 3, nearly 25% of units are more than 10 miles from the nearest natural gas pipeline, and over half are more than 5 miles. Similar distances can be found in Figure 4, with numerous units more than 10 miles from the nearest natural gas pipeline.

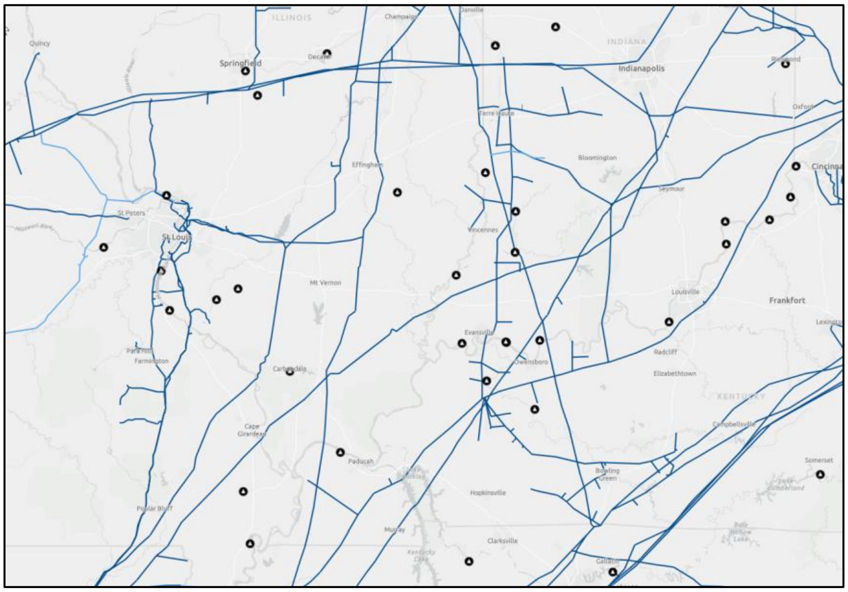

Figure 3. EIA map showing the locations of coal fired power stations and natural gas transmission infrastructure in the Lower Midwest Region.

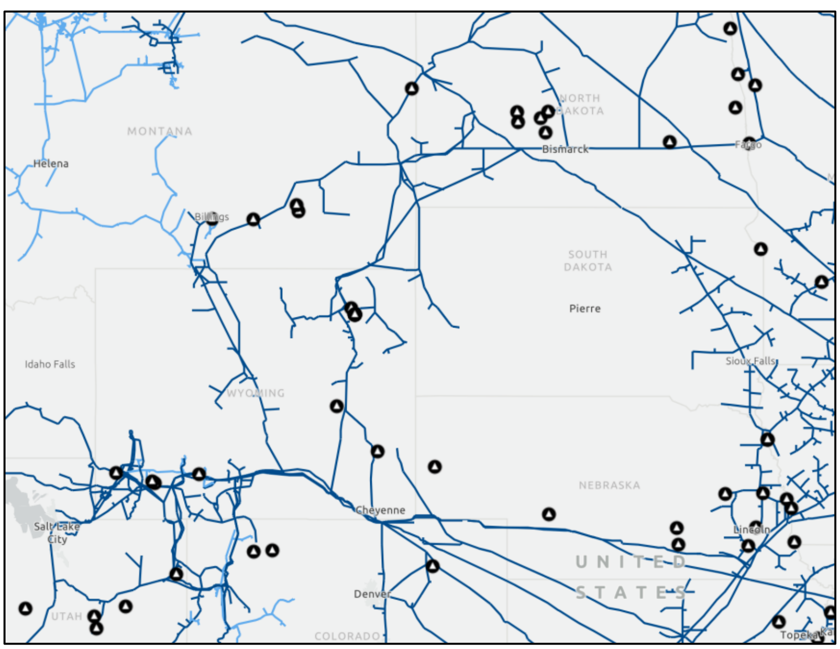

Figure 4. EIA map showing the locations of coal fired power stations and natural gas transmission infrastructure in the Great Plains and Rocky Mountain Region.

Furthermore, the presence of a natural gas pipeline near a plant is not an indication of adequate capacity. For example, Mr. John Weeda, technical expert and consultant to NRECA, is experienced with the Coal Creek Station north of Bismarck, ND. Figure shows a gas line just east of the plant, however, that line does not even have enough capacity to provide ignition fuel for the 1,100 MW coal plant. The nearest pipeline with adequate capacity is over 40 miles from the plant.

The referenced EPA document states that "Even if a generator doesn't necessarily report burning natural gas, in many cases, coal-fired EGUs are located in the vicinity of other generating assets. In the cases where coal-fired EGUs are located near natural gas EGUs, they likely have access to an existing supply of natural gas." This speculation or overgeneralization is no substitute for actually evaluating the availability of natural gas to the units the EPA would make subject to this rule. Pipeline companies need to have lines subscribed to as full an extent as possible for their businesses to be successful. As a result, excess capacity to feed a large unit transitioning from coal to natural gas is often not possible with existing infrastructure.

For example, Mr. Weeda is in discussion with a pipeline company about the potential to supply approximately 100 MW equivalent of gas to a peaking plant being planned as backup to a wind and solar installation in eastern Montana. Although, an existing line runs adjacent to the site, it is unclear whether supplying the plant is even possible. An in-depth analysis of the pipeline's capacity and the potential to shift capacity would be required. In short, proximity to a pipeline alone is not even sufficient to make co-firing, let alone substantial co-firing, a viable option.

Difficulty and Cost Associated with Procuring Natural Gas Service at a Coal Plant

The EPA assumes that natural gas is available at coal plants to provide natural gas co-firing as an option for compliance. However, this is not the case during extreme weather events like winter storms (as discussed extensively in the section "Availability of Natural Gas During Periods of Inclement Weather and High Demand"), for certain plants in certain locations, and can be extremely expensive or impossible for others.

For example, on a simple map, Associated Electric Cooperative's New Madrid Station in Missouri appears close to existing natural gas pipeline infrastructure. However, when the cooperative researched the cost of obtaining natural gas service at their site, the closest pipeline with capacity and pressure to support the plant is located 46 miles away, with an estimated capital cost of $213,798,000 to connect to the plant. At Associated Electric Cooperative's Thomas Hill facility, the closest gas line is 14 miles away, with an estimated capital cost of $59,500,000 to connect. These are likely typical costs for many more power plants. The EPA, however, does not seem to have accounted for these substantial costs in its analyses for the proposed rule. Securing the right-of-way (ROW), surveying, and permitting can be expected to take three years with construction, and another two years if there are not any litigation or challenges to the permits. That is highly unlikely, as recent history of vociferous opposition to natural gas pipelines shows. Even when natural gas service is in close proximity, the cost of connecting to a suitable service line can be prohibitively expensive and is unlikely to be available by 2030.

Furthermore, in the case of Arizona Electric Power Cooperative, Inc. (AEPCO), steam unit 2 of the Apache Generating Station has been converted to natural gas, but additional firm natural gas transportation is not available on the natural gas supply pipeline. If coal-fired steam unit 3, which is the same size as steam unit 2, were converted to natural gas, the current metering station, piping, and transportation contracts would require modifications to reliably deliver the additional gas to the site.

Arkansas Electric Cooperative Corporation has estimated that to continue operating one of their coal-fired units until 2040, less than its remaining life, they would need to invest $70 million to $120 million by 2030, just to bring natural gas to the plant site in order to co-fire with natural gas. Necessary retrofits to the plant to enable co-firing would require additional investment.

Plant Design Challenges

The design challenges that need to be addressed in the conversion of a coal unit to co-fire or fully-utilize natural gas are significant in most cases. The Sargent & Lundy report "Natural Gas Co-Firing Memo" that the EPA references devotes less than a page to this important topic. The mass of the gas from natural gas combustion is different than the mass of gas from burning coal. The flame temperature and the attachment of the flame to the wall of the boiler, the safety characteristics of handling natural gas, the boiler controls for natural gas, and many other factors all need to be considered. In other words, this is a major engineering study of conversion that EPA's single page description does not adequately represent. For example, adding or increasing flue gas recirculation will likely be needed and adding hundreds of horsepower. Heat transfer in the boiler surfaces would be affected, requiring modification or addition of heat transfer surface. The exit gas temperature from the boiler would typically increase, causing shortened life on the equipment at the back of the boiler and downstream. The heat rate measure of unit efficiency is typically negatively affected. A detailed engineering analysis would have to be completed by each unit owner to determine the feasibility of a gas conversion.

For example, AEPCO's Apache Station in Cochise, AZ converted one approximately 200-MW boiler to natural gas and the other one remains on coal. In the conversion process, the need was identified to double the size of the flue gas recirculation system and to direct it to the burner area. Despite these changes, the exit gas temperature of the boiler runs hot and is destructive to equipment in the back pass of the boiler and downstream.

Similarly, Mr. Weeda was responsible for the engineering group at a 1,100-MW lignite-fired power plant. The thermal sciences engineer in the group evaluated natural gas conversion. His findings determined that the large volume of the boiler designed for lignite firing would have major heat transfer imbalance with the enormous difference in flue gas volume with natural gas. This would significantly reduce the efficiency of the boiler, leading to capacity loss, equipment failures, inability to make steam temperature, and other challenges. It is fair to say that most large lignite boilers would experience similar engineering limitations, preventing co-firing from being an achievable option, due to the economics of such a large change. Sargent & Lundy, in their experience report, stated that modifications are more extensive for plants of 500 MW or more.

Cost

Table 1 on page 15 of the EPA Steam EGU TSD includes estimated capital cost and impact on energy cost for a hypothetical "representative" unit. The estimated capital cost is not representative of an actual project when considering all costs of the project including investment in natural gas infrastructure. For example, in the EPA's own "Documentation for Lateral Cost Estimation" the EPA references assume a $151/kW average for pipeline costs, but the EPA arbitrarily decides in its technical support document to use the *median* value of pipeline cost of $92/kW, undercutting that average cost by nearly 40%.[11]

Even with the cost included in this table, for many small entity utilities – such as electric cooperatives and municipal power utilities – that have large generating units that would be impacted by these regulations, the estimated cost would be devastating to their ability to compete in the market. For example, if AEPCO were to convert their other Apache Station coal boiler to natural gas, the pipeline company has told them that the capacity of the gas line is not adequate to supply both units. Therefore, they would more than likely have to purchase delivered natural gas, exposing them to market volatility in fuel pricing.

For many of those small entity utility plants, the costs in the table would increase the incremental cost of generation by 50% to 100%. This would remove the motivation to make the conversion, as the plant would run extraordinarily little at the higher price.

Conclusion

The EPA's proposed rules do not contain practical options for converting current coal generation capacity to natural gas-firing. The evidence provided in this document identifies problems with design considerations, general availability, cost of conversion, cost of operation and adverse weather reliability. These factors will negatively impact the already tenuous condition of generating resources on the electricity grid.

About the Authors

Dr. William Morris, Carbon Management Strategies, LLC

Dr. William Morris completed his Ph.D. and M.S. in chemical engineering at the University of Utah, examining the effect of pollutants such as NO_X, SO_X, and particulate matter on aerosol formation in air and oxy-fired combustion for CO_2 capture. He also holds a coordinate A.B. in Physics and Environmental Studies, with a minor in History from Bowdoin College. He is currently president and technical director of Carbon Management Strategies LLC. He is also contracted by the Wyoming Energy Authority (WEA) as Program Director to provide

[11] U.S. Environmental Protection Agency. Office of Air and Radiation. *Documentation for Lateral Cost Estimation.* April 2023. Available here: https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0061/attachment_11.pdf

engineering and business development support services for CO_2 management technologies testing at the Wyoming Integrated Test Center (ITC). The ITC facility is a public/private venture between Basin Electric Power Cooperative, Tri-State G&T, the National Rural Electric Cooperative Association, Black Hills Power, and the state of Wyoming through the Wyoming Infrastructure Authority. The research facility can provide up to 23 MW equivalent of flue gas for large pilot post combustion CO_2 capture testing, as well as 6 small 0.4 MWe test bays which have hosted the NRG COSIA Carbon XPRIZE CO2 utilization competition as well as a post combustion capture system from TDA Research. Additional projects in the procurement phase are Kawasaki Heavy Industries solid adsorbent technology, Membrane Technology and Research's 180 tonne per day membrane CO_2 capture facility, and another 24 ton per day membrane capture system led by Gas Technology Institute and the Ohio State University.

As an employee of ADA Environmental Solutions, Dr. Morris worked in the areas of mercury emissions control, CO_2 capture, NO_X control, and is the listed inventor on 3 issued NO_X, mercury, and CO_2 emissions control patents, as well as other patents pending. He was also a contributing author to the oxy-fuel combustion section of the National Coal Council's report, *Fossil Forward,* in 2015 for then Department of Energy Secretary of Energy, Ernest Moniz, providing an update on CO_2 capture technologies. In addition, he was the CO_2 use chapter co-lead with Professor Alissa Park of Columbia University for the National Petroleum Council's report, *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. He has conducted basic research, small pilot research, and commercial scale demonstrations and trials of various mercury, NO_X, and emissions control technologies with both private industry and universities. Commercialization success included developing a novel coal treatment process to qualify for the IRS section 45 refined coal tax credit, which produced approximately $1.8 billion in tax credits. Previous partners have included University of Utah, University of California Berkeley, Texas A&M University, Lehigh University, Southern Company, Aspen Aerogels, The University of Akron, the Electric Power Research Institute, the National Energy Technology Laboratory, the U.S. Department of Energy, and other private industry companies. In addition, he has been a peer reviewer for the journals of American Chemical Society as well as Elsevier Publishing.

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having "all of the above" energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment L

Comments of the Power Generators Air Coalition on EPA's Proposed Rule Entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)"

87 Fed. Reg. 79,176 (Dec. 23, 2022)

Docket ID No. EPA-HQ-OAR-2021-0527

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") on its proposed rule entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)," which was published in the Federal Register on December 23, 2022 (hereinafter, "Proposed Rule").[1] The Proposed Rule proposes to amend the regulations governing implementation of emission guidelines under section 111(d) of the Clean Air Act ("CAA" or "the Act").

I. Background

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[2] Our members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired electric generating units ("EGUs"), as well as renewable resources like wind and solar. Greenhouse gas ("GHG") emissions from new, modified, and reconstructed fossil fuel-fired EGUs are regulated under section 111(b) of the CAA. Because GHGs are neither a criteria air pollutant under the Act's national ambient air quality standards ("NAAQS") program nor regulated as a hazardous air pollutant under section 112 of the Act, GHG emissions from existing fossil fuel-fired EGUs owned and operated by PGen members will be subject to regulation under section 111(d). As such, PGen has an interest in the Proposed Rule.

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[1] 87 Fed. Reg. 79,176 (Dec. 23, 2022).

[2] Additional information about PGen and its members can be found at https://pgen.org/.

EPA's proposed revisions to the section 111(d) implementing regulations are important. While historically section 111(d) has been invoked only rarely,[3] EPA's regulation of GHGs will lead to this provision being invoked much more frequently and for a broad spectrum of source categories given the ubiquitous nature of carbon dioxide ("CO_2") (a GHG) emissions. EPA recently proposed a section 111(d) emission guideline rule to regulate methane (another GHG) emissions from existing sources in the oil and natural gas sector,[4] and has announced plans to release a proposed rule regulating GHG emissions from fossil fuel-fired EGUs under section 111(d) in the next few months. PGen has been working with EPA regarding how best to regulate CO_2 emissions from existing EGUs, including meeting with EPA in November 2022, and submitting comments to EPA's pre-proposal non-rulemaking docket in December 2022.[5]

As part of the Affordable Clean Energy Rule,[6] EPA amended its section 111(d) implementing regulations to promulgate a new Subpart Ba of 40 C.F.R. part 60, which would apply to any emission guidelines issued after July 18, 2019. The original section 111(d) implementing regulations are promulgated as Subpart B and apply to emission guidelines issued before that date. Part of the Subpart Ba amendments included changing the deadlines for submittal and approval of state plans (and where necessary promulgation of federal plans) to align them with the deadlines in section 110 of the CAA for state implementation plans ("SIPs") under the NAAQS program. This aspect of the Subpart Ba regulations was challenged in the U.S. Court of Appeals for the D.C. Circuit. The court vacated the extensions of the compliance periods contained in Subpart Ba because it found that EPA had failed to adequately explain why the extensions were needed and because it further found that EPA had failed to address what the public health and environmental effects would be from the extension of the compliance periods.[7] The Proposed Rule proposes new timing provisions for Subpart Ba in response to the court's decision.

As an initial threshold matter, it is important for EPA to recognize that Congress limited its role under section 111(d). Unlike section 111(b) of the Act where EPA controls all aspects of a performance standard for new and modified sources in a source category, section 111(d) is a state-driven program. Under section 111(d), it is the states that "establish[] standards of performance for any existing source … to which a standard of performance … would apply if such existing source were a new source."[8] EPA must allow the state "in applying a standard of performance to any particular source under a plan … to take into consideration, among other

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[3] *See* 87 Fed. Reg. at 79,179.

[4] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[5] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Comments on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723-0031 (Dec. 22, 2022) (hereinafter, "Pre-Proposal Comments").

[6] 84 Fed. Reg. 32,520 (July 8, 2019).

[7] *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 991-95 (D.C. Cir. 2021).

[8] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1).

factors, the remaining useful life of the existing source to which such standard applies."[9] EPA has oversight authority and determines whether a state plan is "satisfactory."[10] If a state fails to submit a satisfactory plan, then EPA puts in place a federal plan and *must* take into consideration the remaining useful life of the source, among other factors ("RULOF").[11] In promulgating these implementation regulations for section 111(d), EPA should be careful to honor the cooperative federalism approach set out by Congress and not encroach on the states' authority. Further, states should be afforded adequate time to develop their state plans, aligned with the state's rulemaking process.

PGen offers the following specific comments on the Proposed Rule.

II. While EPA Acknowledges More Time Is Needed and Attempts to Rectify this Issue, Several of the Timing Provisions Set Forth in the Proposed Rule Do Not Provide Sufficient Time, Are Unrealistic Based on Evidence in the Record, and Will Result in Missed Deadlines.

A. The D.C. Circuit's decision in *American Lung Association v. EPA* does not foreclose longer timelines than those proposed.

It is important to note at the outset that the D.C. Circuit did not hold that the previous timing deadlines under the Subpart Ba implementation regulations were *per se* unlawful. Rather, the court said that EPA had failed to provide an adequate explanation for why the longer timing deadlines were needed (particularly given the fact that a state plan under section 111(d) is "simpler" and of a "different scale" than a SIP) and had failed to examine at all the public health and welfare implications of the longer deadlines.[12]

EPA has included empirical evidence in the preamble to the Proposed Rule that demonstrates that longer deadlines are needed. Indeed, as discussed further below, that empirical evidence shows that some of the deadlines in the Proposed Rule need to be longer to avoid missed deadlines. EPA needs to ensure that the deadlines that it sets are realistic and can be met. If deadlines are missed, this only further delays implementation of the program because the clock resets for EPA to promulgate a federal plan. As EPA acknowledges, "[a]llowing states sufficient time to develop feasible implementation plans for their designated facilities … *ultimately helps* ensure more timely implementation of an [emissions guideline], and therefore *achievement in*

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[9] *Id.*

[10] *Id.* § 111(d)(2)(A), 42 U.S.C. § 7411(d)(2)(A).

[11] *Id.* § 111(d), 42 U.S.C. § 7411(d).

[12] *Am. Lung Ass'n*, 985 F.3d at 991-93.

actual emission reductions, than would an unattainable deadline that may result in the failure of states to submit plans and requiring the development and implementation [of a] Federal plan."[13]

To ensure emission reductions are achieved in a timely manner, EPA should extend some of the deadlines in the Proposed Rule, as discussed in further detail below.

B. The proposed deadline for state plan submissions is too short and will be missed, particularly given the increased requirements associated with state plan preparation. (Comments A1-1, A1-2, A1-3, A1-4, and A1-5)

EPA proposes to give states 15 months to submit state plans under section 111(d) unless EPA specifies otherwise in the emissions guideline.[14] EPA provides evidence in the preamble to the Proposed Rule that shows that 15 months is not sufficient and that more time is needed. In the preamble, EPA appropriately examines the time it takes for states to submit plans under section 129 of the CAA.[15] Section 129 plans are very similar to section 111(d) plans, but section 111(d) plans "involve more complicated analyses" because of the fact that section 111(d) allows states to take RULOF into account.[16] EPA is proposing new requirements for states that choose to propose a less stringent standard for a designated facility based on RULOF, and these new requirements will add more time to the state's preparation of a plan. EPA notes that states take on average between 14 to 17 months after publication of an emissions guideline to prepare a state plan under section 129.[17] Given that plans under section 111(d) "permit[] more source-specific analysis," which takes more time, it is clear that 15 months does not provide sufficient time.

In addition to the individualized, source-specific analysis of RULOF that results in a section 111(d) plan taking more time than a section 129 plan, EPA is proposing to add significant new requirements for outreach and engagement.[18] Under the current regulations, a state must hold a public hearing prior to adopting a state plan.[19] In contrast, under the Proposed Rule, a state would be required to "conduct meaningful engagement" with pertinent stakeholders.[20] Meaningful engagement encompasses much more than the current requirement for a public hearing, including "the development of public participation strategies" and "early outreach, sharing information, and soliciting input on the state plan."[21] Depending on the number

[13] 87 Fed. Reg. at 79,183 (emphases added).

[14] Proposed 40 C.F.R. § 60.23a.

[15] 87 Fed. Reg. at 79,183.

[16] *Id.*

[17] *Id.*

[18] *Id.* at 79,190-92; Proposed 40 C.F.R. § 60.23a(i).

[19] 40 C.F.R. § 60.23a(c).

[20] Proposed 40 C.F.R. § 60.23a(i)(1).

[21] *Id.* § 60.21a(k).

of communities that might be affected by the state plan,[22] this outreach could be a significant effort on the part of the states. Because of these new community engagement requirements and the new requirements for states that wish to undergo a RULOF analysis, additional time is needed to ensure that the states can realistically meet the deadline. The proposed time of 15 months simply is insufficient.

States may also have unique procedures that could further lengthen the time they need.[23] For example, some states require a state plan to be approved by the state legislature, and many state legislatures meet only for a few months a year. Depending on when in the legislative cycle a state plan is completed and ready for state legislative review, it may be several months before the legislature is back in session. This provides yet more justification for why additional time is needed for states to submit plans.

In the Proposed Rule, EPA compares state plan preparation under section 111(d) to preparation of attainment plans for the 2012 $PM_{2.5}$ NAAQS, which had a statutory deadline of 18 months from the date an area was designated nonattainment.[24] EPA fails to acknowledge, however, that states have *much* more notice that they have an area that is nonattainment long before the area is formally designated nonattainment. Looking at the complete timeline for the 2012 $PM_{2.5}$ NAAQS shows the true amount of time states have to prepare attainment SIPs. The 2012 $PM_{2.5}$ NAAQS were finalized on January 15, 2013.[25] At that point, states had notice that they may have areas that are not in attainment with the NAAQS. Indeed, the Governors of each state have to submit initial designations regarding attainment of a NAAQS within one year of a NAAQS being promulgated.[26] EPA finalized the designations for the 2012 $PM_{2.5}$ NAAQS for most areas on January 15, 2015—*two years* after the NAAQS were finalized—and those designations became effective on April 15, 2015.[27] The 18-month time period for states to submit their attainment SIPs that EPA references in the Proposed Rule[28] began to run on that effective date (i.e., April 15, 2015). In examining how long a state has to prepare attainment SIPs, EPA needs to account for all the time leading up to the running of the 18-month clock where the state had notice that they had a nonattainment area. In this case, that was a period of *27 months* (January 15, 2013, to April 15, 2015), bringing the total amount of time the states had to prepare attainment SIPs to *45 months* (i.e., nearly four years).[29] In contrast, with regard to

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[22] *See id.* § 60.21a(l).

[23] 87 Fed. Reg. at 79,182 n.9 (acknowledging "[i]n many states, the agency must submit its rule to a particular independent commission or the legislature for review and approval before the rule is finally adopted").

[24] *Id.* at 79,183.

[25] 78 Fed. Reg. 3086 (Jan. 15, 2013).

[26] CAA § 107(d)(1)(A), 42 U.S.C. § 7407(d)(1)(A).

[27] 80 Fed. Reg. 2206 (Jan. 15, 2015).

[28] 87 Fed. Reg. at 79,183.

[29] Even if one assumes that the state did not have notice that it had a nonattainment area at the time the NAAQS was finalized, it is absolutely true that the state knew a year later when the

state plan submission under section 111(d), there is not a period of years where a state knows what it is going to have to do before the clock begins to run. A state does not know what EPA's determination of the BSER and the resulting presumptive level of stringency is until the final emissions guideline is issued.

In its Pre-Proposal Comments, PGen suggested that a minimum of two years is needed for submission of state plans from the time of publication of a final emissions guideline.[30] Since that time, however, PGen has seen that states are saying that even more time than two years is needed, and PGen respectfully suggests that EPA defer to the states regarding how much time is needed for state plan submission as they are in the best position to know what is involved in preparing a plan. For example, the State of Tennessee recently said in its comments on EPA's proposed section 111(d) emissions guideline for the oil and gas sector that given the new requirements for RULOF and community engagement that it needed 30 months to prepare its state plan.[31]

As discussed above, the D.C. Circuit's decision in *American Lung Association v. EPA* did not foreclose the current deadlines; rather, EPA must provide a better explanation for why that amount of time is needed. As further discussed above, the evidence provided by EPA in the preamble to the Proposed Rule demonstrates that the proposed time of 15 months is insufficient.

C. PGen supports the proposed 60-day limit for EPA to determine completeness of state plans. (Comment A2-1)

PGen generally supports EPA's proposal to require EPA to determine whether a state plan is complete within 60 days after receipt of the plan. Under the Proposed Rule, a state plan would be deemed automatically complete by operation of law if EPA misses this deadline.[32] As EPA notes, the completeness determination is a "ministerial" one that "requires no exercise of discretion or judgment on the Agency's part."[33]

PGen is concerned, however, that a state plan that is automatically deemed complete by operation of law could later be disapproved by EPA because it is missing something that should have been caught during the completeness determination process. This would unfairly impact the state because the clock for a federal plan would start ticking. The state should not be penalized for making a mistake that should have been caught during the completeness determination

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Governor made the initial designations. That still provided the state with 33 months to prepare and submit its attainment SIP, which is far more than the 18 months EPA references in the Proposed Rule.

[30] Pre-Proposal Comments at 15.

[31] Tennessee Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review at 6, Docket ID No. EPA-HQ-OAR-2021-0317-2157 (Feb. 7, 2023).

[32] Proposed 40 C.F.R. § 60.27a(g)(1).

[33] 87 Fed. Reg. at 79,184.

process, and if the only reason a state plan would face disapproval is because it is missing something that should have been caught during that review, the state should be given a reasonable period of time to cure the defect before the plan is disapproved and before the federal plan clock begins to run.

D. EPA does not appear to be giving itself enough time to act on state plans based on the evidence in the record. (Comment A3-1)

Under the Proposed Rule, EPA proposes to give itself 12 months after a state plan is determined to be complete (either by EPA or by operation of law) to determine whether the plan is "satisfactory." PGen notes that based on the evidence presented in the preamble to the Proposed Rule, this timeline appears to be unrealistic. EPA provides the following timelines and steps for the Agency to make a determination that a state plan is satisfactory:

- First, EPA has to evaluate a state plan, draft a proposed action on the plan, and have that proposed action edited, reviewed, and signed. According to EPA, this typically takes between 6 to 8 months.[34]
- Second, the proposed action needs to be published in the Federal Register, which EPA says can take several weeks of processing.[35]
- Third, the public must be given at least 30 days to comment on the proposed action, and this might be extended if requested.[36]
- Fourth, EPA has to review the comments, prepare updated recommendations for review, consult with agency decision makers, prepare a final rule, prepare a response to comments document and any necessary record support, and possibly prepare proposed regulatory text. EPA says this typically takes between 4 to 7 months.[37]

Assuming the *average* amount of time under these estimates, it is apparent that the 12-month deadline is unrealistic: 7 months for step one + 0.5 months to publish in the Federal Register + 1 month for public comment + 5.5 months to prepare final rule = 14 months. Only the *best-case scenario* might make this deadline (meaning everything happens at the low end of EPA's estimates and the rule is published in the Federal Register within one week): 6 months for step one + 1 week to publish + 1 month for comment + 4 months to finalize the rule = 11.25 months. It is unlikely that the review of every state plan can meet the high hurdle of the best-case scenario.

PGen suggests that EPA consider giving itself more time to ensure that it has adequate time to review state submissions. This is far preferable to the current proposal, which sets the

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[34] *Id.* at 79,185.

[35] *Id.*

[36] *Id.*

[37] *Id.* at 79,185-86.

Agency up to miss a deadline—or worse puts EPA in a position where it needs to rush to meet an unreasonable deadline and acts in a less than thorough manner. PGen suggests that EPA consider setting a deadline for itself between 14 months (the average scenario) and 18 months (a scenario on the longer side of the estimates).[38]

E. EPA should ensure it has sufficient time to consider remaining useful life, as is required under the CAA, when it is promulgating a federal plan. (Comment A4-1)

PGen is concerned that EPA has not provided itself with sufficient time to consider RULOF when it is promulgating a federal plan. EPA has proposed to give itself 12 months to promulgate a federal plan after either: (a) a state fails to submit a state plan by the deadline; or (b) EPA disapproves a state plan because it fails to meet the "satisfactory" standard.[39] EPA needs to ensure that it gives itself enough time to consider RULOF in its preparation of a federal plan. Unlike states where this consideration is optional, Congress *requires* EPA to take RULOF into account.[40] Particularly given the proposed additional requirements around RULOF, EPA needs to ensure it has enough time to conduct this important analysis.

As previously stated with regard to EPA's review and action on state plans, EPA should not set itself up for failure. Rushing to meet an unreasonable deadline will not result in a federal plan that considers all affected facilities in a meaningful way, including RULOF. EPA provides the following timelines and steps for the Agency to promulgate a federal plan:

- First, EPA has to form an intra-agency workgroup that develops recommendations for the components of the federal plan, including determining the standards of performance for designated facilities that generally reflect the presumptive level of stringency of the emissions guideline, including possible adjustments based on RULOF, any testing, monitoring, reporting, and recordkeeping requirements, and that complies with the meaningful engagement requirements of the Proposed Rule. The recommended components of the federal plan are reviewed and then a proposed federal plan is drafted, along with a technical support document. The proposed federal plan is then reviewed by the relevant EPA offices and signed. According to EPA, this step typically takes "a minimum" of 6 to 9 months.[41]

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[38] The scenario based on the longer side of the estimates is calculated as follows: 8 months for step one + 1 month to publish in the Federal Register + 2 months for public comment + 7 months to prepare final rule = 18 months.

[39] Proposed 40 C.F.R. § 60.27a(c).

[40] CAA § 111(d)(2), 42 U.S.C. § 7411(d)(2) (noting "the Administrator *shall* take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which a standard applies") (emphasis added).

[41] 87 Fed. Reg. at 79,187-88.

- Second, the proposed federal plan needs to be published in the Federal Register, which EPA says can take several weeks of processing.[42]
- Third, notice of at least 15 days must be given for a public hearing where members of the public can submit oral comments on the proposed federal plan, and notice of at least 30 days must be given for submission of written comments on the proposed federal plan. Because of the public hearing requirement, EPA says it "should allow for at least 45 days for public comment."[43]
- Fourth, EPA has to review the comments, prepare updated recommendations for review, consult with agency decision makers, prepare a final federal plan, prepare a response to comments document and any necessary record support, and prepare proposed regulatory text. EPA says this typically takes between 4 to 8 months.[44]

Assuming the *average* amount of time under these estimates, it is apparent that the 12-month deadline is unrealistic: 7.5 months for step one + 0.5 month to publish in the Federal Register + 1.5 months for public comment and public hearing + 6 months to prepare final rule = 15.5 months. Only the *best-case scenario* might make this deadline (meaning everything happens at the low end of EPA's estimates and the rule is published in the Federal Register within one week): 6 months for step one + 1 week to publish + 1.5 months for comment and public hearing + 4 months to finalize the rule = 11.75 months. It is unlikely that the preparation of a federal plan will always be able to meet the aggressive timelines of a best-case scenario.

PGen suggests that EPA consider giving itself more time to ensure that it has adequate time to promulgate a federal plan so that it does not set itself up to miss a deadline—or worse rush to meet an unreasonable deadline and set itself up for a legal challenge that it failed to adequately consider RULOF or another requirement. PGen suggests that EPA consider setting a deadline for itself between 16 months (the average scenario) and 20 months (a scenario on the longer side of the estimates).[45]

F. The timeline for increments of progress should run from EPA's approval of a state plan—not from the state plan submission deadline. (Comment A5-1)

PGen believes that it is reasonable to require states to show increments of progress when a compliance schedule for a state plan is going to extend more than 16 months.[46] PGen is concerned, however, with connecting the timing of the increments of progress to the state plan submission deadline. States should not be required to begin implementation on a state plan until

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[42] *Id.* at 79,185, 79,188.

[43] *Id.* at 79,188.

[44] *Id.*

[45] The scenario based on the longer side of the estimates is calculated as follows: 9 months for step one + 1 month to publish in the Federal Register + 2 months for public comment and public hearing + 8 months to prepare final rule = 20 months.

[46] Proposed 40 C.F.R. § 60.24a(d).

they know that EPA has approved it. As a result, the timing of increments of progress needs to be tied to the date EPA approves the plan—not the state plan submission deadline. EPA suggests that "[p]roviding a 2-month buffer after approval of plans but before the increments of progress are required allows for the owner or operator of designated facilities reasonable time to initiate actions associated with the increments of progress."[47] PGen believes that this does not provide a reasonable period of time.

Thus, PGen respectfully suggests that EPA require that state plans include increments of progress for any compliance schedule extending more than 16 months from EPA's *approval* of the plan.

G. EPA should continue to link the authority and timeline for a federal plan to a finding of failure to submit. (Comment B-1)

EPA proposes to revise the section 111(d) implementing regulations to link the 12-month clock for EPA to issue a federal plan to the missed state plan submission deadline—rather than what it is linked to now, which is a finding of failure to submit on the part of EPA.[48] As EPA notes, "a finding of failure to submit has value in notifying states and the public of the status of plans."[49] While the Agency says that it will still issue a finding of failure to submit, it says it will do so "anytime between the deadline for state plan submissions and the EPA's promulgation of a Federal plan."[50] The value of a finding of failure to submit is greatly diminished, however, the closer it occurs to the time a federal plan is issued, and is practically valueless if it occurs right before a federal plan is issued. The preparation and publication of a finding of failure to submit is not an onerous task that requires particular agency expertise or many man hours. There is no reason why this could not be done easily once the deadline has been missed.

EPA should not remove its own obligations and deadlines to issue a finding of failure to submit. The 12-month clock should continue to run from the publication of a finding of failure to submit.

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[47] 87 Fed. Reg. at 79,189.

[48] *Compare* Proposed 40 C.F.R. § 60.27a(c)(1) (requiring a federal plan be issued "after … [t]he State fails to submit a plan or plan revision within the time prescribed") *with* 40 C.F.R. § 60.27a(c)(1) (requiring a federal plan be issued "after the Administrator … [f]inds that a State fails to submit a required plan or plan revision").

[49] 87 Fed. Reg. at 79,190.

[50] *Id.*

III. EPA's Enhanced Requirements for Outreach and Meaningful Engagement Will Require States to Need More Time for State Plan Preparation, Could Strain Limited State Resources, and Need to Be More Clearly Defined if They Are Part of the Completeness Determination. (Comments C-1, C-2, and C-4)

EPA proposes significant new requirements for outreach by states to communities that are "most affected by and vulnerable to the impacts" of a state plan.[51] PGen agrees with EPA that public outreach, particularly with vulnerable communities, is valuable and worthwhile as a policy matter. EPA needs to consider, however, how these enhanced requirements add a layer of complexity to state plan development that will increase the time needed for states to submit state plans to EPA, and the Agency further needs to consider how these increased requirements may strain already limited state resources.

Under the current regulations, a state is simply required to hold a public hearing.[52] In contrast, the Proposed Rule would require states to "conduct meaningful engagement," with "pertinent stakeholders."[53] Pertinent stakeholders are defined to "include … industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revisions."[54] In addition, meaningful engagement encompasses much more than the current requirement for a public hearing, including "the development of public participation strategies" and "early outreach, sharing information, and soliciting input on the state plan."[55] Depending on the number of communities that might be affected by the state plan, this outreach could be a significant effort on the part of the states (and can be even more time if the state invokes RULOF to propose a less stringent emission limitation for a designated facility).[56] All of these requirements, while laudable and good public policy, need to be accounted for in the amount of time that a state will need to prepare a state plan.

Under the Proposed Rule, as part of the completeness determination, a state plan must include "[e]vidence of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, and a summary of stakeholder input received."[57] EPA specifically asks for comment on whether evidence of meaningful engagement should be included in the completeness criteria.[58] PGen does not object in theory to the idea of meaningful engagement being part of the completeness analysis, but it does respectfully suggest that before this can be required that EPA needs to provide much more information to the states as to what exactly the state needs to do and what evidence it needs to provide in the state plan to be

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[51] *Id.*

[52] 40 C.F.R. § 60.23a(c).

[53] Proposed 40 C.F.R. § 60.23a(i)(1).

[54] *Id.* § 60.21a(l).

[55] *Id.* § 60.21a(k).

[56] *Id.* § 60.24a(k).

[57] *Id.* § 60.27a(g)(2)(ix).

[58] 87 Fed. Reg. at 79,192.

considered complete. The Proposed Rule as currently written is too vague, and states will be unsure of exactly what it is that they are required to do for a plan to be considered complete, leading to the determination of "completeness" potentially being overly subjective.

Finally, EPA's statement that meaningful engagement with pertinent stakeholders will "help ensure that plans achieve the appropriate level of emission reductions"[59] has no basis as a matter of law under the CAA. Under section 111(a)(1) of the Act, a standard of performance "reflects the degree of emission limitation achievable through the application of the [BSER]."[60] While meaningful engagement with the public and with vulnerable communities is generally good public policy, it does not have any bearing on the emission reductions that are achieved under section 111.

IV. EPA's Proposed Regulatory Mechanisms for State Plan Implementation (Comment D-1)

EPA is proposing to incorporate five regulatory mechanisms as amendments to the implementing regulations: (1) partial approval and disapproval of state plans; (2) conditional approval of state plans; (3) parallel processing of state plans; (4) a "state plan call"; and (5) error correction. PGen generally supports most of these proposed revisions, with the exception of the "state plan call" amendment.

Partial Approval and Disapproval (Comment D1-1). EPA proposes to revise the implementation regulations to add a provision similar to section 110(k)(3) of the CAA that would allow EPA to "partially approve or partially disapprove a state plan when portions of the plan are approvable, but a discrete, severable portion is not."[61] PGen supports this proposed revision.

Conditional Approval (Comments D2-1 and D2-2). EPA proposes to revise the implementation regulations to add a provision similar to section 110(k)(4) of the Act that would allow EPA to conditionally approve a state plan "that substantially meets the requirements of an [emissions guideline] but that requires some additional specified revisions to be fully approvable."[62] After conditional approval, a state would have one year to adopt and submit the necessary revisions to EPA. PGen supports this proposed revision and believes that one year is a sufficient amount of time for the state to submit the necessary revisions. Under the Proposed Rule, if a state failed to meet this one-year deadline, the conditional approval would automatically convert to a disapproval, which would begin the clock for EPA to issue a federal plan. PGen supports this proposed revision, but reiterates its concerns, expressed above in Section II.E., that the one-year period of time for EPA to promulgate a federal plan seems unrealistic based on the evidence EPA provides in the preamble to the Proposed Rule regarding how long it typically takes to issue a federal plan. Any deadline for a federal plan following a

[59] *Id.*

[60] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

[61] 87 Fed. Reg. at 79,193; *see also* 40 C.F.R. § 60.27a(b)(1).

[62] 87 Fed. Reg. at 79,193-94; *see also* 40 C.F.R. § 60.27a(b)(2).

conditional approval should match the amount of time generally given for EPA to promulgate such a plan.

Parallel Processing (Comments D3-1, D3-2, and D3-3). EPA proposes to revise the regulations "to include a mechanism similar to that for SIPs under 40 CFR part 51 appendix V, section 2.3.1., for parallel processing a plan that does not meet all of the administrative completeness criteria."[63] This provision would provide a state with additional time to complete its process to fully adopt the plan. PGen supports this proposed revision.

State Plan Calls (Comments D4-1, D4-2, D4-3, and D4-4). EPA proposes to add to the section 111(d) implementation regulations a provision similar to section 110(k)(5) that would allow EPA to call for revision of a state plan if EPA "find[s] that a previously approved state plan does not meet the applicable requirements of the CAA or of the relevant [emissions guideline]."[64] EPA notes that such an action "would be generally appropriate under two circumstances": (1) "when legal or technical conditions arise after the EPA's approval of a state plan that undermines the basis for the approval" (such as a subsequent court decision or design assumptions about control measures proving to be inaccurate); or (2) "a state fails to adequately implement an approved state plan."[65]

With regard to the first circumstance proposed by EPA (where legal or technical conditions arise that undermine the basis for EPA's approval), PGen believes that this situation can be rectified under the Error Correction provision that EPA proposes because the approval in these circumstances would have been "in error."[66]

With regard to the second circumstance proposed by EPA (where a state is failing to adequately implement an approved state plan), this situation is addressed directly in section 111(d)(2)(B) of the CAA, which specifies that EPA has "the same authority … to enforce the provisions of [a state] plan in cases where the State fails to enforce them as [the Administrator] would have under sections [113 and 114 of the CAA] with respect to an implementation plan."[67] Congress thus directed EPA not to call for a revision of a state plan, but instead to employ the federal enforcement measures set forth in sections 113 and 114 of the Act. This forecloses EPA from employing a "state plan call" to address a situation where a state plan is not being adequately implemented. For this reason, the proposed State Plan Call revision is unauthorized and should not be finalized.

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[63] 87 Fed. Reg. at 79,194.

[64] *Id.*

[65] *Id.* at 79,194-95.

[66] Proposed 40 C.F.R. § 60.27a(j).

[67] CAA § 111(d)(2)(B), 42 U.S.C. § 7411(d)(2)(B).

Error Correction (Comments D5-1 and D5-2)

As a general matter, PGen does not object to the proposed revisions that allow EPA to correct a situation where a plan was approved, disapproved, or promulgated in error.[68] This provision could be used in the event of a court decision that undermines the basis of an EPA decision on a state plan or to correct any typographical errors that might have occurred in a final rule. EPA should make clear in the regulations, however, that this provision cannot be used to effect a change in policy because of a change in perspective on implementation that may arise from an administration transition. Designated facilities need regulatory certainty, and the error correction provision should not be able to be used to radically change a designated facility's requirements.

V. EPA Should Be Careful Not to Unduly Limit the Discretion that Congress Gave States to Consider RULOF.

Congress directed that EPA's implementing regulations under section 111(d) "shall permit the State in applying a standard of performance to any particular source under a plan submitted [under section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[69] While EPA has the authority to approve or disapprove of a state plan, it should not unduly limit a state's discretion to take RULOF into account. PGen generally supports EPA's proposed regulations regarding the steps that a state must take to apply a standard of performance to a designated facility that is less stringent than otherwise required by the emissions guideline based on RULOF.

A. EPA needs to be clear that if a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that the RULOF provisions do not apply. (Comment E2-1)

PGen suggests that EPA make more clear that the RULOF provisions set forth in proposed § 60.24a(f) are required *only* when a state is proposing a less stringent emission standard for a designated facility, and these provisions do not apply if a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA. If a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, EPA needs to approve that state plan as "satisfactory." This conclusion is implied in the preamble to the Proposed Rule, which states that:

> [T]he proposed RULOF provisions … would apply where a state intends to *depart* from the presumptive standards in the [emissions guideline] and propose a less stringent standard … and not where a state intends to *comply* by demonstrating that a facility or group of facilities subject to a state program would, in the aggregate,

[68] Proposed 40 C.F.R. § 60.27a(j).

[69] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1).

> achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the [emissions guideline] at individual designated facilities.[70]

This conclusion is further implied in the proposed § 60.24a(g), which says that a state "may not apply a less stringent standard in cases where a designated facility can reasonably implement a technology or other system of emissions reduction other than one identified as the [BSER] to achieve the degree of emission limitation required by an emission guideline."[71]

To avoid any potential confusion on this point, EPA should be clear in the preamble to the final rule that the RULOF provisions are required *only* when a state is proposing a less stringent emission standard for a designated facility—not when a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA.

B. PGen supports EPA's revisions that would allow for operational conditions based on remaining useful life or restricted operating capacity as a basis for setting a less stringent standard. (Comment E5-1)

PGen agrees with EPA's proposed approach for contingency requirements that would allow a state to invoke RULOF on the basis that a source "is running at lower utilization … than is anticipated by the BSER and intends to do so for the duration of the compliance period…."[72] As PGen stated in its Pre-Proposal Comments, existing fossil fuel-fired EGUs that operate rarely should be allowed to comply with alternative emission limitation requirements, and "[t]hese units could be subject to limitations on the amount they may operate in a given year."[73] There may be important reliability reasons why an electric generator may want to keep open a plant that is used rarely. Companies will not be willing to invest large sums in such a unit. Allowing states to invoke RULOF to allow for a less stringent standard for these facilities makes good sense.

PGen also agrees with the Proposed Rule's requirement that where a state plan contains a less stringent emissions limitation for a designated facility based on RULOF "on the basis of an operating condition(s) within the designated facility's control, such as remaining useful life or restricted capacity, the plan must also include such operating condition(s) as an enforceable requirement."[74] PGen also agrees with the approach where a state may change its plan in the future to address changes in operating conditions.[75]

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[70] 87 Fed. Reg. at 79,198 (emphasis in original).

[71] Proposed 40 C.F.R. § 60.24a(g).

[72] 87 Fed. Reg. at 79,200.

[73] Pre-Proposal Comments at 7.

[74] Proposed 40 C.F.R. § 60.24a(h).

[75] 87 Fed. Reg. at 79,201 (noting "a state may submit a plan revision to reflect [a] change in operating conditions" and "[s]uch a plan revision must include a new standard of performance that accounts for the change in operating conditions").

C. PGen generally supports EPA's proposal regarding how retirements may factor into state plans. (Comment E6-1)

EPA proposes to allow states to apply a less stringent standard on the grounds that a designated facility will retire within a period of time identified by EPA or determined by the states through a methodology provided by EPA.[76] PGen supports this proposal. As PGen said in its Pre-Proposal Comments, states should be permitted to provide alternative, less-stringent emission limitation requirements in their state plans for fossil fuel-fired EGUs that will retire within a reasonable amount of time.[77] PGen appreciates that EPA has made clear that "[i]f a designated facility's retirement date is both imminent and prior to the outermost retirement date identified in an emission guideline, the plan may apply a standard that reflects the designated facility's business as usual."[78]

As EPA knows, the electric generation industry is undergoing a transition away from fossil fuel-fired generation. As a result, many EGUs may not operate until their useful lives have expired, and EPA's Proposed Rule adequately takes that into account. States should be able to require less from units that are not expected to operate much longer under their consideration of RULOF. Owners and operators will not want to put significant monetary resources into units that will not be operating in the near future. If required to do so, these units may be prematurely retired, and this could have significant impacts on electric reliability.

In the Proposed Rule, EPA proposes to establish a date or a methodology for determining what announced retirement dates will qualify for alternative emission limitation requirements in an emissions guideline. PGen asks EPA in setting any retirement deadline for EGUs in its upcoming proposed emissions guideline for fossil fuel-fired EGUs to consider other statutes and regulations that may be driving retirements, such as EPA's Effluent Limitations Guidelines for fossil fuel-fired EGUs. EPA should coordinate the deadlines in these other rules with the outer limit that it establishes for retirements under section 111(d).

VI. PGen Supports EPA's Proposed Revisions to Change the Definition of Standard of Performance and to Allow Compliance Flexibility.

EPA proposes to revise the section 111(d) implementation regulations "to clarify that the definition of 'Standard of performance' allows for state plans to include standards in the form of an allowable mass limit of emissions."[79] PGen supports this proposed change. As PGen said in its Pre-Proposal Comments, "EPA should allow a state to express the emissions limits as a mass-based emission rate (e.g., tons of CO_2 per year)…."[80]

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[76] Proposed 40 C.F.R. § 60.24a(i).

[77] Pre-Proposal Comments at 7.

[78] Proposed 40 C.F.R. § 60.24a(i)(2).

[79] 87 Fed. Reg. at 79,206.

[80] Pre-Proposal Comments at 16.

PGen also agrees with and supports EPA's proposed reversal of its prior interpretation of section 111(d) that prohibited compliance flexibilities, including emissions averaging and trading.[81] States should be permitted to allow emissions averaging, trading, and other flexible measures to aid owners and operators of designated facilities in complying with emissions limitations established under section 111(d). As EPA noted when it proposed the Clean Air Mercury Rule, the Agency's "significant experience" with cap-and-trade programs for utilities has shown that such programs cause emissions to fall *below* the mandated cap, despite increased electric generation, while "maximizing overall cost-effectiveness."[82]

Ensuring that states have maximum flexibility in terms of compliance strategies will result in another significant benefit: electric reliability. As PGen noted in its Pre-Proposal Comments, "[a] trading program will allow fossil fuel-fired EGUs that are rarely used to continue to be operated for the purpose of stabilizing the grid during times of peak load (such as during times of extreme heat or cold or because of an extreme weather event)…."[83] As further discussed in PGen's comments, flexible compliance tools such as emissions trading or averaging have been shown to result in significant benefits to environmental justice communities.[84]

* * *

PGen appreciates the opportunity to comment on EPA's Proposed Rule. If EPA has any questions on PGen's comments, or if EPA would like to meet with PGen members to discuss these comments further, it should contact PGen's counsel below, who will work with PGen's Board of Directors to arrange a convenient time.

Dated: February 27, 2023

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[81] 87 Fed. Reg. at 79,207-08.

[82] 69 Fed. Reg. 4652, 5697 (Jan. 30, 2004); *see also id.* (noting that trading "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces" and that "[s]ources have an incentive to endeavor to reduce their emissions below the number of allowances they receive").

[83] Pre-Proposal Comments at 10.

[84] *Id.* at 10-15 (Section VI).

Attachment M

FINAL REPORT

Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule

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August 7, 2023

Table of Contents

1 SUMMARY

The following summarizes the major issues and flaws of the U.S. Environmental Protection Agency's (EPA) modeling using the Agency's Integrated Planning Model (IPM) of the proposed rule and they are:

- EPA's Updated Baseline is an outlier, when compared to other model forecasts of the electric power sector due to EPA's unrealistically "optimistic" interpretation of the Inflation Reduction Act; whereby, EPA fails to understand and properly consider grid reliability in 2028 and 2030.

- EPA fails to understand and properly consider those issues confronting RTOs and electric utilities during this transition from dispatchable fossil sources to non-dispatchable, intermittent generating sources.

- EPA's Updated Baseline is flawed based upon erroneous coal retirements and retrofitted CCS units in 2030.

2 INTRODUCTION

On May 11, 2023, the U.S. Environmental Protection Agency (EPA) announced proposed new standards and guidelines for greenhouse gas emissions from coal and gas-fired power plants. As a part of this rulemaking effort, EPA modeled the estimated impacts this proposed rule would have upon the electric power sector using its Integrated Planning Model (IPM). These modeling results appear in the Regulatory Impact Analysis (RIA), which accompanied the proposed rule announcement. However, on July 7, 2023 EPA issued "updated" IPM modeling runs which resulted in an Updated Baseline and a new Integrated Proposal (Policy Case) for the proposed rule. It is these two new modeling runs that are evaluated in this report.

3 IPM'S MODELED UPDATED BASELINE IS AN OUTLIER

This discussion presents a general overview of various models used to project public policy impacts on the electric power sector, specifically as they apply to environmental regulations. The focus here, is to compare and discuss in general terms how the results from EPA's Integrated Planning Model (IPM) compares to other models in predicting policy impacts on the electric power sector. Depending on available information, some models present more data than others. One of the major points of evaluation is to see how the Inflation Reduction Act (IRA) was handled by each model and how it impacts the future generating capacity levels in the electric power sector and the potential impacts on grid reliability, specifically in the years 2028 and 2030.

The Base/Reference Cases, that are illustrated in Appendix 3.0, represent modeled outputs that includes the IRA and various environmental regulations. In addition, to evaluating the impacts of the IRA on the electric power sector, there is also an IPM simulation of the Integrated Proposal (i.e., proposed GHG Emission Standard and Guidelines) on the electric power sector.

3.1 Overview of Models

As mentioned above, the primary focus was comparing model results from IPM to other models used in evaluating public policy impacts on the electric power sector. Those models are as follows:

- EPA's IPM – IPM is EPA's principal modeling tool to evaluate economic and compliance impacts on the electric power sector. Two modeling scenarios were evaluated: (i) Pre-IRA 2022 Reference Case (January 2023); and, (ii) Post-IRA 2022 Reference Case (March 2023). The Pre-IRA 2022 Reference Case was used in modeling the compliance and economic impact of the proposed Effluent Limitation Guidelines (ELG) rule, published on March 29, 2023, while the Post-IRA 2022 Reference Case, which is the Updated Baseline, was used in modeling the economic and compliance impacts of the proposed MATS Residual Risk and Technology Review (RTR) and Carbon Standard. Both IPM reference cases use the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2021 to forecast future electrical demand.[1]
- EIA's National Energy Modeling System (NEMS) – NEMS is an economy-wide modeling system that EIA uses in its annual AEOs. For this analysis, *AEO 2023's Reference Case* (March 2023) modeling of the electric power sector was evaluated, which included the IRA.[2]

[1] Information on IPM can be found at www.epa.gov/power-sector-modeling
[2] Information on NEMS can be found at www.eia.gov/outlooks/aeo/

- NREL's Regional Energy Deployment System (ReEDS) – ReEDS is an optimization model used to measure policy impacts on the electric power sector. The specific modeling that was evaluated in this discussion appears in *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (March 2023). The two specific cases that were evaluated were: (i) IRA-BIL Mid Case; and, (ii) IRA-BIL Constrained Deployment.[3] ReEDS uses AEO 2022 Reference Case to forecast future electrical demand.[4]
- EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (REGEN) – REGEN is a capacity planning and dispatch model of the electric power sector. The specific modeling that was evaluated in this discussion appears in *Power Plant Performance Standards and Tax Credit Interactions: Impacts of Design Decisions and the Inflation Reduction Act on the U.S. Power Sector – An EPRI White Paper (*March 2023). The Reference Case was evaluated, which includes all On-the-Books federal and state policies and incentives, including IRA as of November 2022.[5]
- RFF Haiku – Haiku is a simulation model of regional electricity markets and interregional electricity trade in the continental United States. The model accounts for capacity planning, investment, and retirement over a multi-year horizon in a perfect foresight framework, and for system operation over seasons of the year and times of day. The specific modeling that was evaluated in this analysis appears in *A New Baseline for the Power Sector: Insights from the Haiku and E4ST Models* (February 15, 2023), which includes the IRA.[6]

3.2 Inclusion of IRA Provisions

Table 3-1 lists those IRA provisions that were accounted for in each model. The focus is on provisions that apply to the electric power sector.

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[3] Mid Case – Moderate cost and performance for all technologies and delivered fuel prices are from the AEO2022 Reference Case. Constrained Deployment – Reduced land area/resources available for renewable development, new long-distance transmission build restricted to historical national average build rate (1.4 TW-mi per year), Increased (2x) cost of CO2 pipeline, injection, and storage infrastructure.

[4] Information on ReEDS can be found at www.nrel.gov/analysis/reeds/

[5] Information on REGEN can be found at www.epri.com/research/products/000000003002016601

[6] Information on Haiku can be found at www.rff.org/topics/data-and-decision-tools/haiku-electricity-model/

Table 3-1. Inflation Reduction Act Provisions in Each Model

Provision	IPM	AEO2023	ReEDS	REGEN
Production Tax Credit Extension	√	√	√	√
Investment Tax Credit Extension	√	√	√	√
New Clean Electricity Production Credit (45Y)	√	√	√	√
New Clean Electricity Investment Credit (48E)	√	√	√	√
Manufacturing Production Credit (45X)	√			
CCS Credit (45Q)	√	√	√	√
Nuclear Production Credit (45U)	√	√	√	√
Production of Clean Hydrogen (45V)	√			√
Solar in Low-Income Communities				√

As shown in Table 3.1, the number of provisions accounted for in each model varies. Of note, there was very little guidance from the Internal Revenue Service (IRS) when these models were run to evaluate the IRA. For example, ReEDS did not capture all the provisions that could directly or indirectly impact the electric power sector. Specifically, it did not capture the tax credit for clean energy production (45V) or the 45Q tax credit for direct air capture and storage of CO2.[7] Indeed, modeling any IRA impacts given the lack of guidance requires numerous subjective decisions. Consequently, the cost of monetizing tax credits under various IRA scenarios becomes important and can impact the effect of IRA on the electric power sector. For example, EPRI's REGEN model estimates an almost 37.5 percent reduction in Levelized Cost of Energy (LOE) for both On-Shore Wind and Utility-Scale Solar in 2030.[8] While ICF, which runs IPM for EPA, estimates IRA incentives could drive down solar by as much as 35 percent and wind by 49 percent by 2030.[9]

But more importantly, the IRA is still evolving through guidance making it somewhat difficult to model. An example of this evolvement can be seen through the three major clean energy tax provisions related to the production and investment tax credits, which have seen their guidance

[7] The IRS requested comments on these two provisions asking commenters to specify issues on which guidance is needed. The comment period closed December 3, 2022.

[8] Bistline et al, *Economic Implications of Climate Provisions of the Inflation Reduction Act*, Brookings Papers on Economic Activity, Spring 2023.

[9] ICF, *5 Actions for Utilities to Prepare for the IRA Impacts*, 2023

documents stretched over several months. The initial guidance of the Prevailing Wage & Apprenticeship provision (Notice IR-2022-61) was issued on November 30, 2022, while the initial guidance for the Domestic Content Bonus (Notice IR-2023-102), was issued on May 12, 2023, and the guidance for the Energy Community Bonus Credit (Notice IR-2023-29) was released on April 4, 2023. However, on June 15, 2023, the IRS released an update of the Energy Community Bonus Credit (Notice IR-2023-45) clarifying a special rule for beginning new construction.

Also, the IRS has asked for comments on several provisions, such as the Production of Clean Hydrogen (Notice IR-2022-58), which were due on December 3, 2022, but have yet to release any initial guidance. The IRS wanted commenters to specify issues for which guidance was needed.

3.3 Coverage of Environmental Regulations

Table 3-2 lists those environmental regulations that were accounted for in each model. REGEN did not list specific environmental regulations, but it does consider non-CO2 emission constraints.

Table 3-2 List of Environmental Regulations Included in Each Model

Regulation	IPM	AEO2023	ReEDS	REGEN
Proposed GNP	√			
CSAPR	√	√	√	
New, Modified GHG Standards: EGUs	√	√		
MATS	√	√	√	
Various Current and Existing State Regulations[10]	√	√	√	
Current and Existing RPS & Clean Energy Standards	√	√	√	√
Regional Haze and BART	√			
CA AB 32 and RGGI	√	√	√	√
Non-air Regulations: 316(b), ELG and CCR	√			

3.4 Modeled Coal Capacity

As shown in Table 3-3 below, all models forecast coal capacity in their Base/Reference Case to be in excess of 100 GW in 2030, except IPM which projects 69 GW in 2030.[11] IPM's 2030 coal capacity is almost 40 percent below, the average coal capacity projected by the other models.

[10] IPM's and ReEDs Current and Existing State Regulations are through 2020; whereas AEO2023 seem to be through 2021.
[11] It should be noted, that both REGEN and Haiku estimates are based upon an approximation of coal, renewable/storage, and natural gas capacity from figures in each report.

When EPA modeled the proposed Good Neighbor Policy (Transport Rule), IPM projected 2030 coal capacity to be 132 GW, which illustrates that the coal capacity forecasted under the proposed GNP will be higher than some projections without the proposed GNP, as shown in Table 3-3.[12] Therefore, the major diver in reducing coal capacity from 2028 to 2030 in the Updated Baseline is the modeler's assumptions about the IRA.

This proportional difference between AEO 2023 and IPM's Updated Baseline increases when one looks at years beyond 2030 due to the IRA. By 2045, IPM's coal capacity is projected to be 70 percent below AEO's. Under the proposed Integrated Proposal, IPM drastically reduces the amount of coal capacity further, to a point where only 500 MW of coal would be operating in 2045. Of note, all coal operating in 2035 and beyond under IPM's Integrated Proposal is equipped with CCS. In IPM's modeling platform, the CCS 45Q provision is available for 12 years, after which a coal unit with CCS no longer receives the tax credits and must be dispatched based upon unsubsidized operating costs.

Table 3-3. Comparison of Forecasted Coal Capacity Levels (GW)

Year	AEO2023	IPM Updated Baseline	EPRI ReGEN	NREL ReEDS - Mid/Const.	RFF Haiku	IPM-Integrated Proposal
2025	164	NA	≈165			
2028	127	100		143.9/154.4		99
2030	102	69	≈104	136.4/140.8	≈112.5	57
2035	92	44	≈99		≈100	13
2040	77.0	36				9
2045	74.1	22				0.5

How this coal capacity is operated varies significantly between the models, as shown in Appendix 3.0 - Operations. Specifically, AEO 2023 coal capacity factors (CF) are expected to remain consistent through the 2028 to 2045 time period (between 38% and 43%). ReEDS, which has the highest level of coal capacity operating in 2028 and 2030, has its coal capacity operating at CF in the high 20 percent ranges. IPM in its Base/Reference Case has coal CFs on a steady decline from 2028 to 2045 (55% to 12%); whereas, under the Integrated Proposal, the IPM CFs are somewhat erratic due to the shrinking level of coal capacity.

3.5 Modeled Renewable and Storage Capacity

As shown in Tab 3-4, the level of renewable capacity that IPM projects in its Base/Reference Case is significantly less that what is projected by the other models. Given the level of coal capacity IPM retires in its Base/Reference Case, one would expect a greater amount of renewable/storage capacity to be installed, especially in 2028 and 2030. Also of note, under IPM's Integrated Proposal, in which future coal capacity is brought to almost zero, the additional renewable/storage capacity only increases by a few gigawatts.

[12] US Environmental Protection Agency*, IPM SSR Report on the Proposed Rule,* March 11, 2022.

Table 3-4. Comparison of Forecasted Renewable/Storage Capacity Levels (GW)

Year	AEO2023	IPM Updated Baseline	NREL ReEDS - Mid/Const.	RFF Haiku	IPM-Integrated Proposal
2025		NA			NA
2028	618	298	676.4/610.1		295
2030	704	397	855.2/808.8	≈1012.5	398
2035	869	671		≈1125	665
2040	1000	871			878
2045	1134	1071			1076

So, what does all this mean? To truly measure the effect of renewable/storage capacity replacing retired coal capacity, one needs to evaluate the difference between future capacity levels with and without the IRA. Both AEO 2023, ReEDS and IPM have modeled a pre- and post-IRA reference cases, which are shown in Appendix 3.0 – Replacement Capacity.[13] The important metric is the amount of Renewable MW required to replace 1 MW of coal. These replacement ratios are highlighted in yellow for AEO, ReEDS and IPM.

As one can see from Table 3-5, AEO 2023 has more than 20 times more renewable/storage capacity replacing one MW of retired coal, while ReEDS have anywhere from 15 to 20 times more renewable/storage capacity replacing one MW of retired coal in comparison to IPM. Whereas, IPM has a very low replacement rate in both 2028 and 2030 and begins to increase slightly in 2035. But more importantly, under IPM's Integrated Proposal, in which coal capacity goes to zero, the replacement ratio is the same as the Base/Reference Case. One major factor that may contribute to these major discrepancies between these three models is how the capacity (accredited) credit is determined from intermittent resources. The capacity credit is an intermittent resource's contribution toward reserve margin requirements during peak load.

Table 3-5. Comparison of Level of Replacement Capacity (GW)

	AEO Renewable to Coal Replacement	ReEDS Renewable to Coal Replacement	IPM Updated Baseline Renewable to Coal Replacement	IPM Integrated Proposal Renewable to Coal Replacement
2028	41.4	14.9	1.5	1.4
2030	19.5	22.6	1.8	1.8
2035	24.2		5.3	5.3
2040	21.6		9.1	9.0
2045	23.9		9.6	9.6

[13] NEMS modeled a scenario in AEO 2023 without IRA along with its Reference Case, which included IRA and as mentioned earlier, IPM modeled a Pre- and Post-IRA 2022 Reference Case.

Why are these replacement ratios a concern? Because renewable generation is dependent on uncontrollable factors such as the amount of sunshine or wind, the installed capacity of a renewable resource reflects the amount of generation at peak energy-producing weather. To account for the variant nature of the weather, transmission organizations typically do not count on the installed capacity of a renewable resource when assessing reliability. Given the operating characteristics of these renewable resources, for example, PJM indicated one needs multiple megawatts to replace 1 MW of dispatchable, thermal generation.[14] Some examples of approximate nameplate capacity needed to replace 1 MW of thermal generation: (i) Solar – 5.2 MW; (ii) Onshore Wind – 14 MW; and, (iii) Offshore Wind – 3.9 MW. This seems to be the underlying premise behind AEO 2023 and ReEDS's higher levels of installed renewable/storage capacity: these models are acknowledging a concern regarding how renewable generation is able to meet its contribution to the reserve margin during peak load; thereby requiring a higher level of grid capacity from other resources (renewables, coal, gas) to avoid reliability issues. The premise is consistent with PJM's assessment of the need for additional megawatts from intermittent resources to fully replace retired coal capacity. It is only in 2035 that IPM begins to have multiple megawatts of renewable capacity replacing one megawatt of coal. Consequently, IPM's low replacement ratios in both 2028 and 2030, raise potential grid reliability issues during that time frame.

3.6 Modeled Natural Gas Capacity

Both AEO 2023 and IPM in the Base/Reference Case and IPM in the Integrated Proposal NGCC and NGCT capacity closely approximate each other, as shown in Appendix 3.0 – Model_Comparisons. Here, natural gas generation appears to be replaced by renewable generation.

ReEDS in its IRA scenarios is the only model that clearly discusses transmission infrastructure. Specifically, ReEDS contain several loan and grant programs to support new transmission infrastructure, which are not modeled but are assumed to facilitate modeled outcomes. Although these programs are not directly modeled, ReEDS increased transmission deployment across the IRA scenarios. Under the IRA Mid case, over 24 TW-miles of new long-distance transmission is deployed by 2030, a 16% increase in total installed capacity relative to today. This observed increase in transmission is largely driven by the increased deployment of wind (and solar) technologies in the IRA cases. The additional transmission enables access to more remote renewable resources and most likely explains ReEDS high levels of renewable/storage capacity in both 2028 and 2030.[15]

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[14] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.

[15] Steinberg et al, *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (March 2023).

3.7 Summary of Key Points

Some key points:

- EPA's modeling of the IRA, when compared to the other models is an unreasonable outlier. in particular regarding modeled coal and renewable/storage capacity in 2030.
- EPA adopted a very "optimistic" approach to the IRA, while lacking guidance from the Department of Treasury.
- EPA assumes IRA's financial provisions will alleviate uncertainties the industry will face during this transition period.[16] These assumptions dismiss concerns regarding supply chain problems, siting, labor shortages, infrastructure.
- EPA failed to understand that intermittent and limited duration resources require multiple megawatts to replace one megawatt of dispatchable generation, specifically in 2028 and 2030; thereby, failing to address grid reliability in 2028 and 2030.
- EPA seems to be dismissing the role of coal, assuming coal units will no longer serve as baseload capacity.

[16] EPRI-Resources of the Future, *Modeling the New Baseline for Electricity in the Presence of IRA*, February 15, 2023.

4 IPM's UPDATED BASELINE DOES NOT CONSIDER KEY CHALLENGES FACING THE POWER SECTOR'S TRANSITION FROM DISPATCHABLE FOSSIL GENERATION TO RENEWABLES

EPA's IPM 2030 Updated Baseline modeling fails to address and account for grid reliability issues confronting the electric power sector by replacing firm power with non-firm renewable generation without any consideration of the different nature of these two types of generating assets.

As discussed, in Section 3, EPA's IPM 2030 Updated Baseline failed to model enough new capacity to replace the level of coal-fired capacity retired in 2030. Consequently, the 2030 Electric Power Profile is flawed and does not reflect the energy mix needed in 2030 to maintain reliability. EPA should consider those major transition and reliability issues that electric generators and RTOs are confronting now and for the next seven years when modeling electric generation in 2030. Specifically, to ensure that the modeling results reflect grid reliability considerations, EPA must consider in its modeling, among others, factors relating to capacity in queues, length of time in the queues, project completion of renewables and accredited capacity of renewable sources.

EPA's current modeling relies on a very optimistic interpretation of the IRA, even though there has been a lack of guidance from the Department of Treasury, when EPA undertook this modeling. Modeling the IRA impacts requires numerous subjective decisions given this lack of guidance. EPA's approach has been, contrary to every other agency and entity that has considered the issue, to make wildly optimistic assumptions and to assess the likely impact of proposed regulatory programs with major impacts on the reliability of the electric grid (and, indeed, the entire American economy) base on these assumptions. In short, EPA simply assumes IRA's financial provisions will alleviate all the uncertainties the industry will face during the ongoing transition towards increasing renewable generation.[17] These assumptions dismiss concerns regarding supply chain problems, siting, labor shortages, infrastructure, permitting and transmission.

Why is it important that EPA in its modeling focus on these reliability issues? In testimony before the US Senate Committee on Energy & Natural Resources, Manu Asthana, President of PJM Interconnection highlighted concerns related to the mismatch between current resource retirements and low entry of replacement capacity as follows: [18]

[17] EPRI-Resources of the Future*, Modeling the New Baseline for Electricity in the Presence of IRA*, February 15, 2023.
[18] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023.
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- The rate of electricity demand is likely to continue to increase from electrification and increasing deployment of high-demand data centers in the region.
- Dispatchable generators are retiring at a rapid pace largely due to government and private sector policies.
- Replacement generation is primarily intermittent and limited-duration resources, requiring multiple megawatts of these resources to replace one megawatt of dispatchable generation.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.

These concerns were further reiterated by James Robb, President and CEO of the North American Electric Reliability Corporation (NERC) at the same Senate hearing, when he stated that the rapid, often disorderly transformation of the generation resource base and performance issues associated with replacement resources as conventional units retire are contributing to the deterioration of the grid.[19] What follows is a discussion of those reliability issues that EPA needs to consider in its modeling

4.1 What is the Interconnection Queue?

The queue for electric generating resources represents the time a project developer initiates an interconnection request and thereby enters the queue, which is followed by a series of interconnection studies. The studies culminate in an interconnection agreement, which is a contract between the RTO or utility. After this interconnection agreement, the project still must be built; however, most proposed projects are withdrawn during the interconnection study process.

Below is a table of capacity in the queue for four RTOs taken from several sources. The PJM interconnection capacity is as of April 1, 2023, while the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) interconnection capacity is of June 28, 2023 and was prepared by S&P Global.[20/21] The Midcontinent Independent System Operator (MISO) capacity data were reported on June 19, 2023 by S&P Global Market Intelligence.[22]

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[19] Testimony of James B, Robb, United States Senate Committee on Energy & Natural Resources, June 1, 2023.

[20] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023.

[21] S&P Global, *2023 U.S. interconnection queues analysis*, June 2023.

[22] S&P Global Market Intelligence*, Grid expansion again in focus as MISO grapples with decarbonization*, June 19, 2023.

Table 4-1. Interconnection Queue Capacity

Region	Interconnection Queue Capacity (GW)	Share of Renewable Capacity (%)
PJM	253	97.2
ERCOT	245	95.1
MISO	281	97.0
SPP	131	95.4

As one can see, these queues are mainly composed of intermittent resources, so the major question is how much of this capacity will eventually get built.

4.2 Small Number of Projects are Actually Built

As shown above, PJM's queue mainly consists of renewable sources; however, these renewable projects have a historical completion rate of 5 percent (queue to steel in the ground).[23] Last year, only 2 GW of capacity was built in PJM, of which only 700 MW (2.3% of the total capacity with signed interconnection agreements) were renewable capacity. This is compared to over 30 GW of generation with signed interconnection agreements.[24]

PJM on July 10th officially launched the transition to "first ready, first served" approach to expedite projects through the queue. This approach includes decision points along the way at which time developers must submit readiness deposits and demonstrate site control or withdraw their projects.[25]

Project completion rates are not only an issue within PJM but nationally. Only 14 percent of solar and 20 percent of wind projects requesting interconnection from filing dates from 2000-2017 reached commercial operation by the end of 2022. In addition, the average time projects are retained in queues has increased markedly. The typical project built in 2022 took 5 years from the interconnection request to commercial operation, compared to 3 years in 2015 and less than 2 years in 2008.[26]

[23] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February, 24 2023.
[24] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023
[25] PJM Inside Lines, *Transition to New Interconnection Process Begins July 10*, July 6, 2023
[26] Rand et al, *Queued U: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022*, Lawrence Berkeley National Laboratory, April 2023.

A major factor that is impacting these completion rates is the various interconnection costs associated with renewable generation. These costs have exploded over the past years suggesting limited transmission availability. For example, in ISO New England (ISONE), interconnection costs are the highest for onshore wind ($909/kW) followed by solar ($400/kW) and storage ($230/kW).[27] Nearly all (81%) of onshore wind projects since 2018 have withdrawn their applications, suggesting that high interconnection costs are a driver of these withdrawal decisions. On the other hand, natural gas interconnection costs are $91/kW. The Berkeley study concluded that many projects facing high interconnection costs withdraw from the queue and renewable and storage projects have higher interconnection costs than natural gas.[28]

Of note, there is no discussion in the EPA's *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model – Post-IRA 2022 Reference Case* (March 2023) of interconnection queues or project interconnection rates.

4.3 The Importance of Accredited Capacity

An important consideration, about new renewable capacity is the ratio of installed capacity to the level of accredited capacity that can be considered to replace retired thermal generation. Accredited capacity reflects how much generation capacity a unit is expected to meet during constrained conditions (accounting for historic performance), which is much less than the installed capacity of the unit for non-dispatchable renewable generation. RTOs have generally applied the following percentages to installed capacity to determine accredited capacity for renewables:

- Wind 15-20%
- Solar (Summer) 45-60%
- Solar (Winter) 3-12%
- Storage 65-90%

These ranges reflect the location and the class of renewable generation source. Of note, in examining EPA's *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model – Post-IRA 2022 Reference Case*, it is unclear how IPM handled accredited capacity for renewable resources, and EPA does not spell out how accredited capacity is handled for various renewable resources.

As discussed earlier, present-day queues are mainly composed of intermittent and limited duration resources. Given the operating characteristics of these resources, PJM indicated the grid would need multiple megawatts to replace 1 MW of thermal generation.[29]

[27] Seel et al, *Generator Interconnector Costs to the Transmission,* Lawrence Berkeley National Laboratory, June 2023.
[28] Id.
[29] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.

For example, MISO expects to retire 26.1 GW of coal capacity over the next seven years (between 2023 and 2030). However, as shown in the table below, MISO's new resources, primarily wind and solar, have a much lower accredited generating capacities than the fossil resources they are replacing.[30] Table 4-2 illustrates the difference between MISO summer installed and accredited capacity for wind and solar today and in 2031

Table 4-2. Comparison of MISO Summer Capacity

	Today		2031	
Category	Installed Capacity	Accredited Capacity	Installed Capacity	Accredited Capacity
Wind	25.6	4.6	56.0	10.1
Solar	4.7	2.1	56.3	12.9

Table 4-2 indicates forward years will encounter a higher degree of uncertainty regarding the accredited capacity available to replace the 26.1 GW of coal capacity by 2031; thereby, putting the region at risk of a capacity shortfall.

Just recently, MISO indicated a possible 2.1 GW accredited capacity shortfall in the summer of 2025 and growing to 9.5 GW in the summer of 2028.[31] These deficits are primarily attributed to MISO's planned accreditation reforms, which could see wind drop from 40% to 14% accredited value in the winter, meaning on paper these megawatts never existed and begin to reveal a major impact on reliability.

4.4 Steps RTOs are Taking to Ensure Reliability

To ensure current grid reliability during this period of energy transition two RTOs and individual generators have taken the following actions:

Southwest Power Pool (SPP). In addition to growing interconnection queues at SPP, the RTO is developing a plan to pay generators to delay retirements to help maintain reliability.[32/33]

Midcontinent ISO (MISO). Delayed retirements of generation units helped reverse a current capacity shortfall in MISO. Units that delayed retirements for reliability reasons are:[34]

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[30] MISO, *2022 Regional Resource Assessment, A Reliability Imperative Report*, November 2022.
[31] S&P Global Market Intelligence, *Midcontinent ISO, states eye possible 2.1 GW capacity shortfall in 2025,* July 17, 2023.
[32] S&P Global Market Intelligence, *Study finds "dramatically' growing interconnection queues, cost in SPP region,* May 17, 2023.
[33] S&P Global Market Intelligence*, SPP details plan to generators to delay retirements, help with reliability*, May 25, 2023.
[34] S&P Global Market Intelligence, *Delayed generator closures helped reverse capacity shortfall in MISO*, May 22, 2023.

- Rush Island (1.2 GW) – 2022 to 2025
- RM Schahfer 17 & 18 (722 MW) - 2023 to 2025
- Edgewater 5 (380 MW) – 2022 to 2025
- Columbia 1 & 2(1.1 GW) – 2024 to 2026
- South Oak Creek (1.1 GW) – 2023/24 to 2024/25

This delayed retirement of a total of 4.5 GW of capacity helped avert a capacity shortfall and ensure a sufficient supply in MISO's recent capacity auction for planning year 2023-24[35]. Of note, there are 24 coal units representing 10 GW of capacity that either delayed retirement or made a total conversion to natural gas due to reliability or supply chain issues.[36] Many of these delays extend into the 2025-2026 time period; however, 4.3 GW or 43 percent of this total are expected to extend to 2030 and beyond. Given the uncertainty around the transition to new generating resources, one can anticipate more retirement delays in the future.

4.5 Summary of Key Points

Unlike AEO 2023, which considered the impact of intermittent resources on the electric power industry, EPA's 2030 Updated Baseline failed to consider issues confronting RTOs and electric utilities about reliability and transition to non-dispatchable capacity. EPA continues to dismiss considerations of grid reliability by accelerating coal plant closures based upon wildly optimistic and wholly unrealistic assumptions about the impact of the IRA on the electric utility sector. EPA's IPM instantaneously "builds" new resources, without considering the many issues discussed above that are facing grid generators and operators. IPM is designed to ensure resource adequacy, which means it adds new resources, without the consideration whether these resources can or will be built. However, IPM is not capable of determining grid reliability because it does not consider the availability of essential reliability services (e.g., availability in all seasons, dispatchability), or other constraints (e.g., transmission) as spelled out by PJM and MISO.[37]
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[35] MISO, *Planning Resource Auction, Results for Planning Year 2023-24*, May 19, 2023.
[36] James Marchetti Inc, *EEMS Data Base.*
[37] PJM, *Evolving Resource Mix and System Reliability*, 2017 and MISO, *Identification of Sufficient System Reliability Attributes,* May 24, 2023.

5 IPM's MODELED UPDATED BASELINE IS FLAWED

The focus of this section is on the IPM 2030 Updated Baseline, because if there are significant flaws in the Baseline, the Integrated Proposal compliance results become unrealistic. The Updated Baseline is the Post-IRA 2022 Reference Case (March 2023), where IPM predicts a significant drop in operating coal capacity in 2030, in comparison to the 2030 operating coal capacity that is modeled for the Effluent Limitation Guidelines (ELG) Pre-IRA 2022 Reference Case (January 2023). Specifically, the Pre-IRA 2022 Reference Case predicts 111.8 GW of operating coal capacity in 2030, while the Post-IRA 2022 Reference Case predicts 68.9 GW of operating coal capacity in 2030, with major shifts to intermittent/non-dispatchable generating sources.

The primary factor contributing to the decline in baseline operating coal capacity, according to EPA, is the inclusion of the IRA in the Post-IRA 2022 Reference Case. The handling of the IRA within IPM causes a significant reduction in baseline coal capacity which distorts actual retirements and reliability, as well as compliance costs attributed to the Integrated Proposal.

The Post-IRA 2022 Reference Case platform uses demand projections from the Energy Administration's Annual Energy Outlook (AEO) 2021. The IPM Post-IRA Reference Case reflects the latest data and regulations affecting the power sector, and they include:

- New Cost and Performance Assumptions for Fossil and Renewable Technologies
- Tax Credit Extensions from the IRA for wind, solar, hydro, geothermal, landfill gas, energy storage, biomass and 45Q
- Minimum Capacity Factor requirements of 10 percent applied to existing coal units in regions without capacity markets
- Updates of Nuclear Unit Operational Assumptions to reflect pre-specified life and are no longer endogenously retired
- CCS Costs and Performance Updated and the 45Q modeled in 2030 and 2035
- Greater Detail on Operating Reserves

The Post-IRA 2022 Reference Case considers compliance with various regulations, which are summarized below:

- Inflation Reduction Act of 2022 (IRA)
- Proposed Good Neighbor Plan (Transport Rule)
- Revised Cross-State Air Pollution Rule (CSAPR) Update Rule
- Standards of Performance for Greenhous Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units
- Mercury and Air Toxics Standards Rule, which was finalized in 2011

- Various current and existing state regulations
- Current and existing renewable portfolio standards (RPS) and current energy standards
- Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART)
- Platform reflects California AB 32 and RGGI
- Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

5.1 Analytical Approach

The focus is to identify those units IPM modeled as coal retirements, CCS retrofits and coal to gas conversions (C2G) in both 2028 and 2030 and compare them to announced plans for unit retirements, technology retrofits and C2G conversions, in addition to identifying any modeling inconsistencies.

EPA did not provide any parsed file for either the 2030 Updated Baseline or Integrated Proposal, so we had to create our own parsed files for the Updated Baseline and Integrated Proposal using four different IPM files: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Updated Baseline and Integrated Proposal RPE File for the year 2030; (iii) Updated Baseline and Integrated Proposal RPT Capacity Retrofits File for the year 2028 and 2030; and, (iv) NEEDS Data File for the Post-IRA 2022 Reference Case.[38] The development of these two parsed files allows for the identification of IPM modeled retirements in 2028 and 2030, CCS retrofits in in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc EEMS Data Base.

This analytical approach yielded 68.1 GW of operable coal capacity (coal, pet coke and waste coal) in the 2030 Updated Baseline, which is roughly the same as, but slightly below IPM's 2030 modeled value of 68.9 GW.[39] In terms of the 2030 Integrated Proposal, this analytical approach yielded 57.9 GW of operable coal capacity, which is slightly higher than IPM's modeled value of 57.3 GW. The closeness of these values indicates the coal inventory we are working with matches the IPM inventory.

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[38] This is tedious work that would have been unnecessary had EPA provided the parsed files, as it has done in the past. It took a long time and prevented us from further analyzing the IPM results that EPA added to the docket after July 7, 2023, and refused to extend the comment period to allow for a more thorough analysis.

[39] U.S. EPA, *Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket* (EPA_HQ_OAR_2023_0072), July 7, 2023.

In addition, to determining the total operable coal capacity in 2030, our approach was able to determine the following; (i) the amount of coal capacity IPM retired in 2028 and 2030; (ii) amount of capacity converted to natural gas (C2G) in 2028 and 2030; and, (iii) amount of coal capacity retrofitted with CCS in 2030.

5.2 Coal Retirements

In the 2028 Updated Baseline model run, IPM had 108 coal units retired (51.4 GW) from 2023 to 2028. In the 2030 model run, IPM retired an additional 58 coal units (28.5 GW). The total number of retirements for the two Updated Baseline modeling runs is 166 coal units (79.9 GW), see Appendix 5.0 – 2028_2030 Coal Retirements.

Table 5-1 summarizes the IPM retirement errors identified in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 41 coal units (18.1 GW) by 2028 and additional 25 coal units (15.9 GW) in 2030 in the Updated Baseline. As shown in Appendix 5.0 – 2028_2030 Coal Retirements, these 66 retirement errors (34.0 GW), which account for almost 40 percent of the modeled retirements in the Updated Baseline are based upon current public information that indicates these units will remain in operation. The Notes section of this appendix presents those sources used to identify these errors. This is an extremely high percentage of erroneous coal retirements, resulting from EPA's unrealistic assumptions of IRA implementation, leading to a significantly comprised Updated Baseline. These errors center around coal units continuing to operate beyond 2028 or 2030 or coal units switching to gas.

Table 5-1. IPM Modeled Coal Retirement Errors

Year	IPM Unit Retirements	Unit Retirement Errors
2028	108	41
2030	58	25
Total	166	66

In addition, there are three coal units (1.6 GW) that EPA listed in its NEEDS file as being retired before 2028 that are expected to operate beyond 2030.

In terms of the Integrated Proposal, IPM retired an additional 17 coal units, resulting in 183 coal units (83.2 GW) being retired through 2030.

5.3 Coal-to-Gas Conversions

The number of units IPM converted in both the Updated Baseline and Integrated Proposal in the 2028 modeling run are the same, as shown in Appendix 5.0 – 2028_2030_C2G. IPM converted 35 coal units (13.7 GW); however, there are 7 coal units (3.0 GW) that have either been mischaracterized or will be retired.

Moving to 2030, IPM converted only two units to gas (Turk and Sandy Creek) in the Updated Baseline. Both seem highly unlikely, since these units are two of the newest coal units operating. In the Integrated Proposal, IPM converted 11 units (7.5 GW), but much like the units in the Updated Baseline, except for Elm Road and Weston 4, the remaining 8 conversions are highly unlikely by 2030 due to either retirements or lack of public announcements on a coal to gas conversion.

5.4 Coal CCS

IPM projected that by 2030, 30 units would retrofit CCS in the Updated Baseline and 39 units in the Integrated Proposal, as shown in Appendix 5.0 – CCS. However, none of these units have been involved in any Front-End Engineering and Design (FEED) Studies. Moreover, of all the units listed 15 will either be retired or converted to natural gas in and around 2030 as provided by the Notes in Appendix 5.0 – CCS. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projections in 2030. Indeed, it is next to impossible for these units to be able to retrofit CSS by 2030, regardless of any optimistic assumptions regarding IRA incentives.

An elaboration of the shortcomings of CCS and rationale as to why such technology cannot be applied to 39 units in 10 years is presented in a technical background document[40] accompanying the comments of APPA and NRECA. The key shortcomings in EPA's projection of CCS applicability are summarized as follows:

- CCS remains an evolving technology, without the basic understanding and experience of a "mature" process. Additional lessons learned have yet to be acquired that are necessary to refine design.

- EPA's prime contractor to develop the implementation schedule – Sargent & Lundy – although projecting a schedule of 7.25 years, clearly state in their deliverable document that the schedule accounts only for "on-site" activities, and not those external to the site but critical for execution.[41] S&L also specify potential "roadblocks and "bottlenecks" that will impose delays.

- The cumulative experience of seven CCS projects that are currently in planning, or the subject of FEED design suggests most will require more than 10 years from "concept" to CO2 injection – with the most uncertainty assigned to permit acquisition for sequestration site or pipelines to transport CO2 for enhanced oil recovery or sequestration.

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[40] Cichanowicz et al, *Technical Comments on the Carbon Capture Utilization and Sequestration aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule,* August 7, 2023.

[41] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

5.5 Coal Delayed Early Retirements

IPM modeled a delayed coal retirement option for 85 facilities representing 45 GW in the 2030 Integrated Proposal. This means these 85 facilities would fall into the Near-Term subcategory for existing coal under the proposed Clean Air Act Section 111d rules, which means they would cease operation after December 31, 2031 and before January 1, 2035 and commit to an annual capacity factor of 20 percent. This means these units must retire by January 1, 2035. However, for 35 of these facilities IPM had modeled their retirement in the 2030 run year, which encompasses the years 2029 to 2031. Plus, IPM installed CCS in 2030 for four of these units. So, the question is why are these previously modeled 2030 retired units and CCS installations included in this subcategory? Their inclusion represents a significant modeling disconnect, bringing into question the entire modeling of this option.

5.6 Other Modeling Issues

Listed below are some other modeling issues that were identified:

- Fayette 3 and San Miguel had CCS installed in the 2030 Updated Baseline, but both units were retired in the 2028 Integrated Proposal
- Leland Olds 2 had a CCS installed in the 2030 Updated Baseline, but was retired in 2030 in the Integrated Proposal
- Coyote was retired in the 2030 Updated Baseline, but was "unretired" in the 2030 Integrated Proposal
- Craig 3 will have retired on December 31, 2029 but in the 2030 Updated Baseline installs a CCS
- Several units could not be found in the 2030 IPM modeling platform – Merom 1&2, Dave Johnston 1 and Morgantown Energy Facility

The retirement of CCS units in the Integrated Proposal defies logic and is a modeling disconnect. One installs a technology to reduce CO2 and take advantage of the 45Q tax credit in the Updated Baseline and is retired in the Integrated Proposal, which is designed to reduce CO2.

5.7 Summary of Key Points

The major issues associated with EPA's IPM modeling of the 2030 Updated Baseline and Integrated Proposal are summarized as follows:

- The Updated Baseline used to measure the compliance impacts of the proposed rules is seriously flawed, mainly attributed to EPA's assumptions on IRA implementation.
- Most notably, IPM erred in retiring 66 coal units representing 40 percent of the retired Updated Baseline coal capacity in 2030, which seriously compromises the baseline.
- IPM assumes retrofitted units with CCS in 2030, which is next to impossible for these units to retrofit CCS by 2030.

- There seems to be some significant modeling disconnects that will further comprise both the Updated Baseline and Integrated Proposal in 2030
- The IPM modeled compliance impacts for the proposed rule in 2030 is very likely misstated.