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. 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] 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

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[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,

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[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-

[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

[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

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[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

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[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]

[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. **<u>NSPS for Fossil Fuel-Fired EGUs</u>**[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.

[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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Attachment A

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

American Public Power Association
Edison Electric Institute
National Rural Electric Cooperative Association
Tri-State Generation and Transmission Cooperative
Indiana Electric Association
WEC Energy Group
LG&E and KU Energy
Salt River Project

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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.

[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/DirectSupercriticalCO_2.

[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

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[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]

[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-CO2-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

[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

[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.

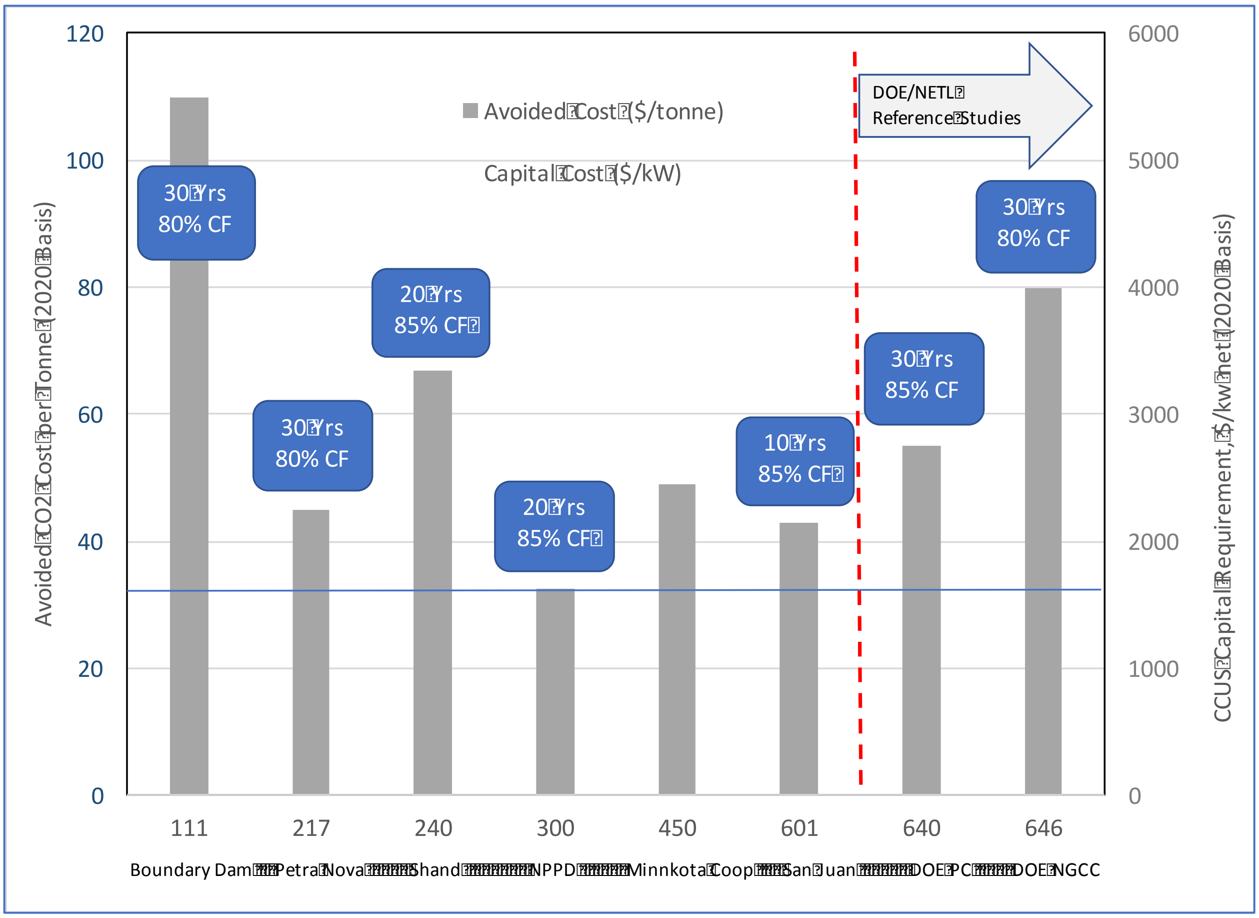

Figure 1-1. Capital Cost, Avoided CO_2 Cost per Facility Lifetime, Capacity Factor

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

[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.

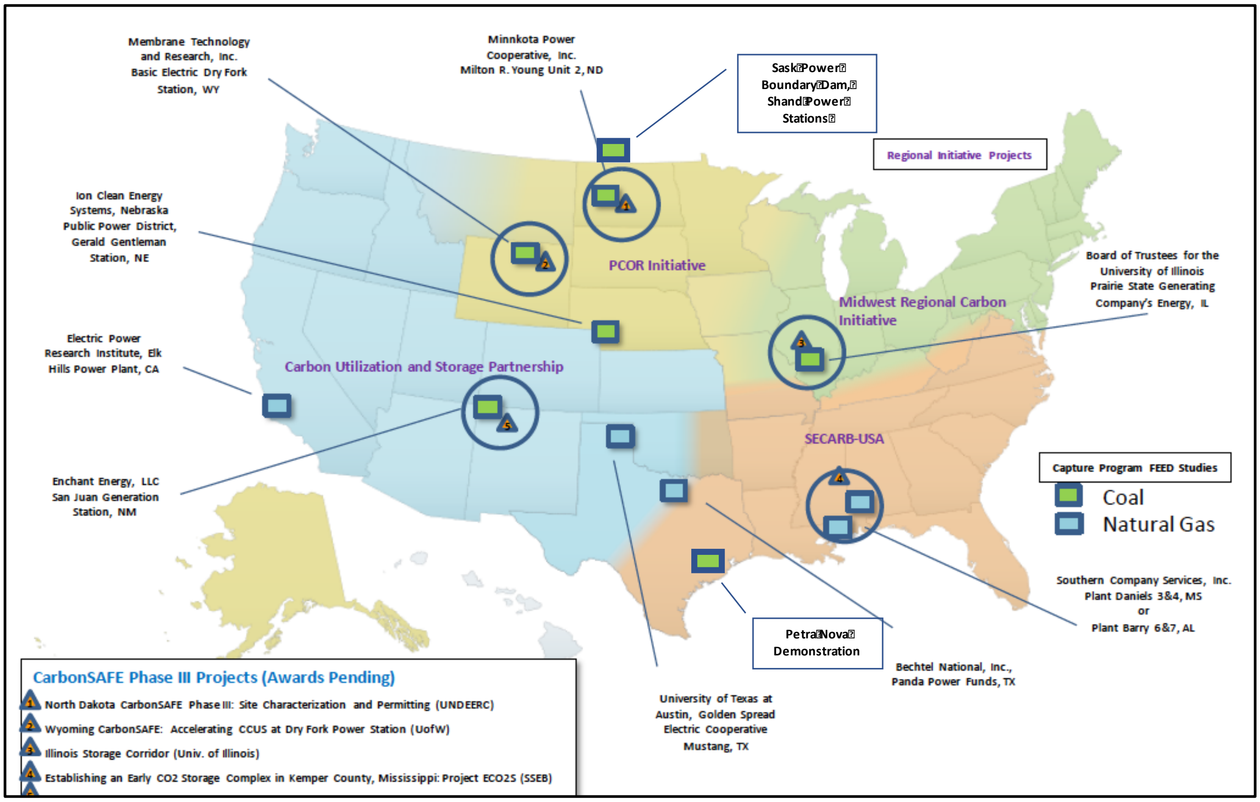

Figure 2-1. Location of CCUS NGCC and Coal-fired Projects in North America

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

<u>Concentration of CO_2 and Oxygen (O_2).</u> 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.

<u>Trace Constituents</u>. 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.

<u>Gas Temperature</u>. 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.

<u>Gas Volume Processed</u>. 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.

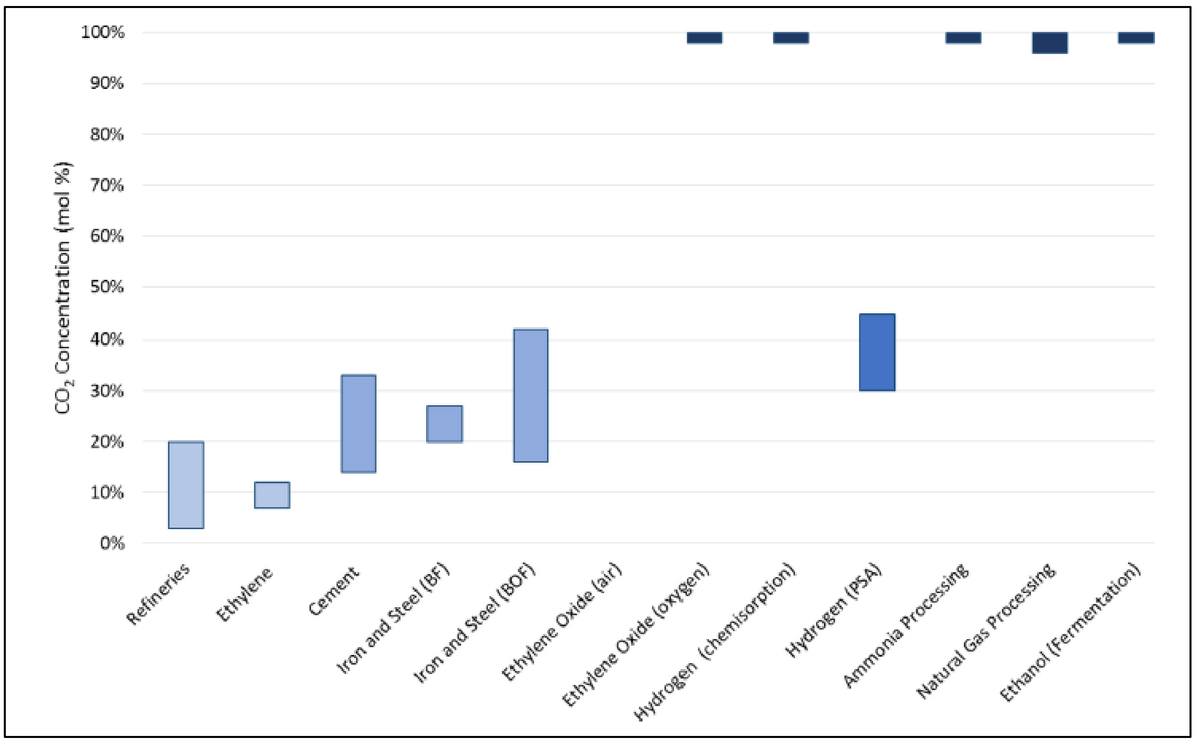

Figure 2-2. CO_2 Concentration (Mol Percent) of Various Industrial Sources

[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.

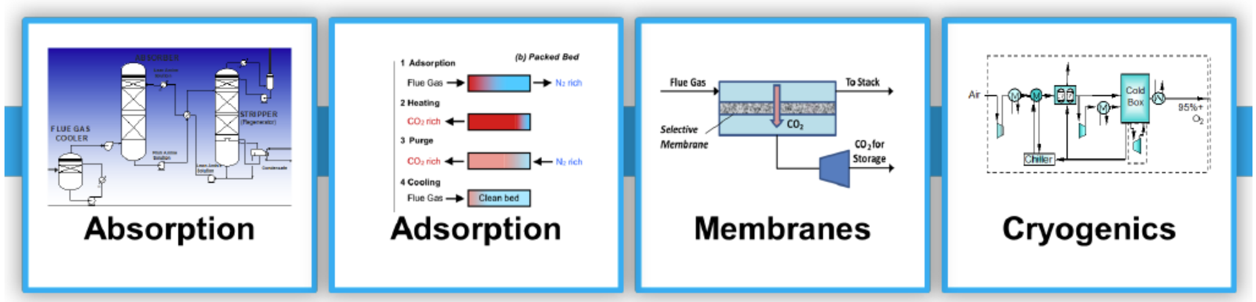

Figure 2-3. Four Categories of Capture Technology

(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

[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.

[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.

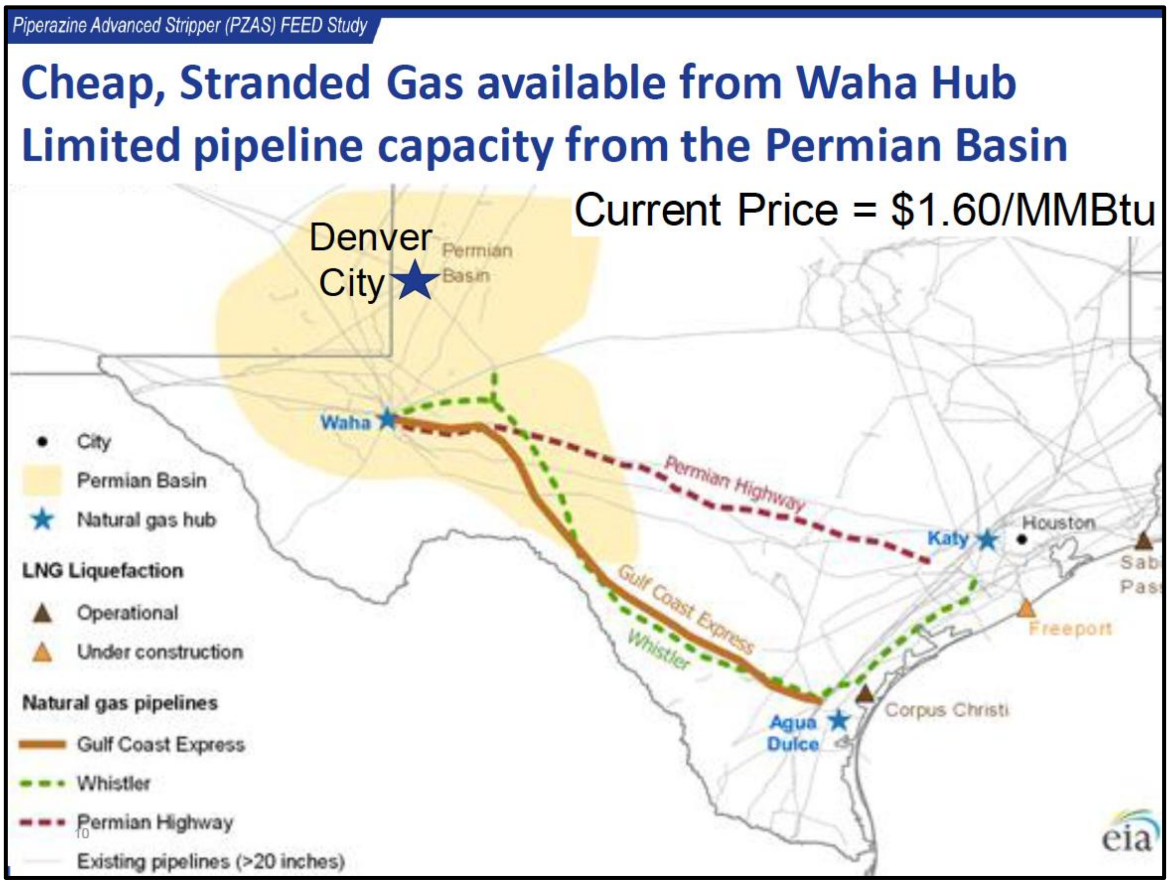

Figure 3-1. CO_2 Pipelines, Permian Basin Access to Mustang Station

A FEED study was to be completed in December 2021.

Summary: 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.

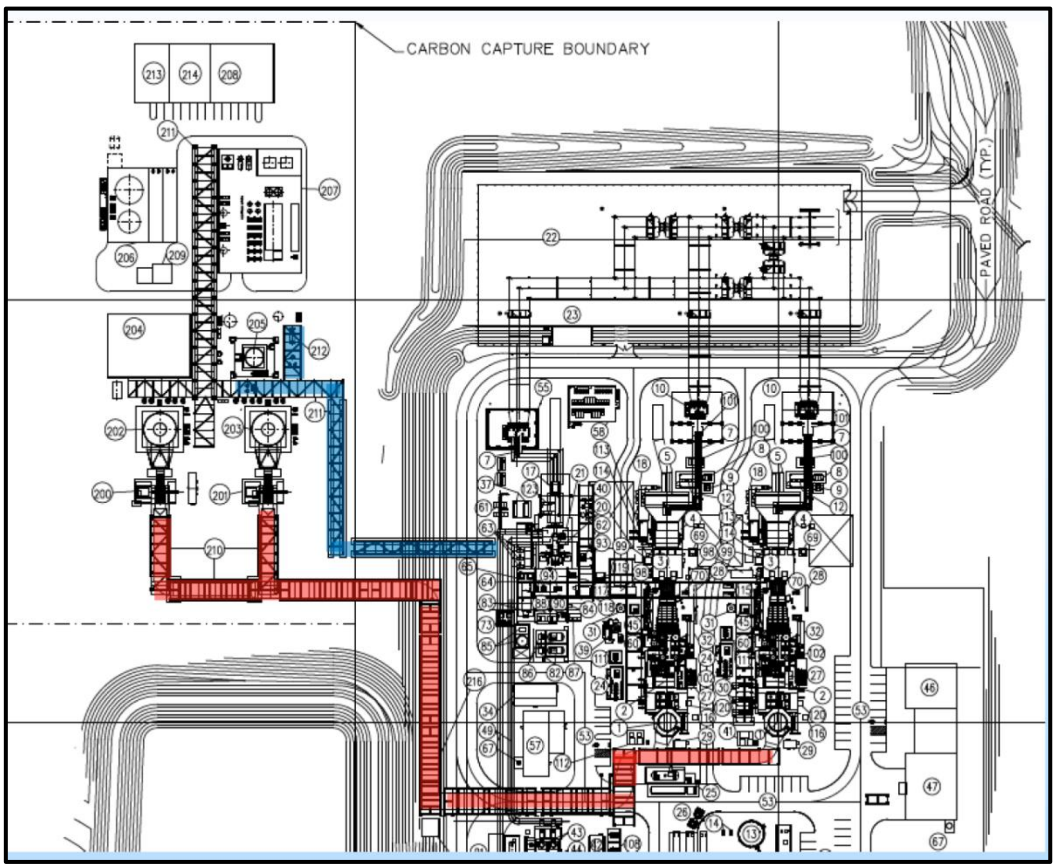

Figure 3-2. Plan Depicting CCUS Footprint: Panda Power

[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.

Summary: 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.

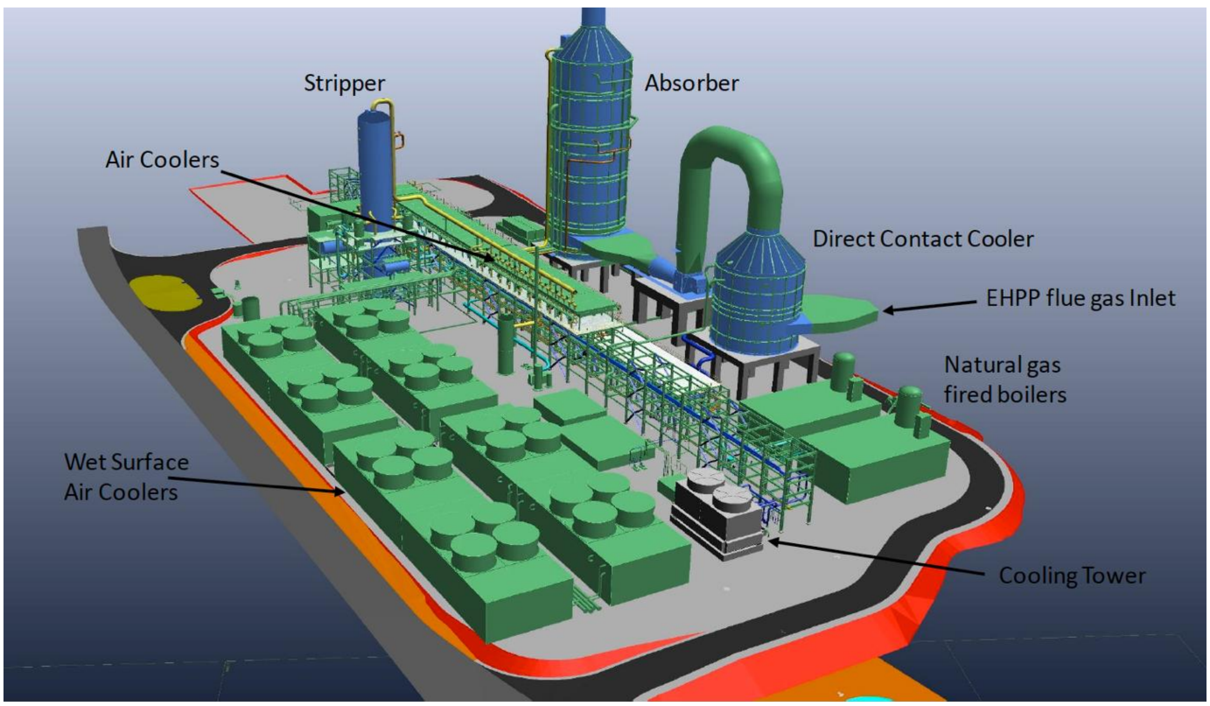

Figure 3-3. Depiction of Process Equipment as Installed: Elk Hills Power Plant

[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.

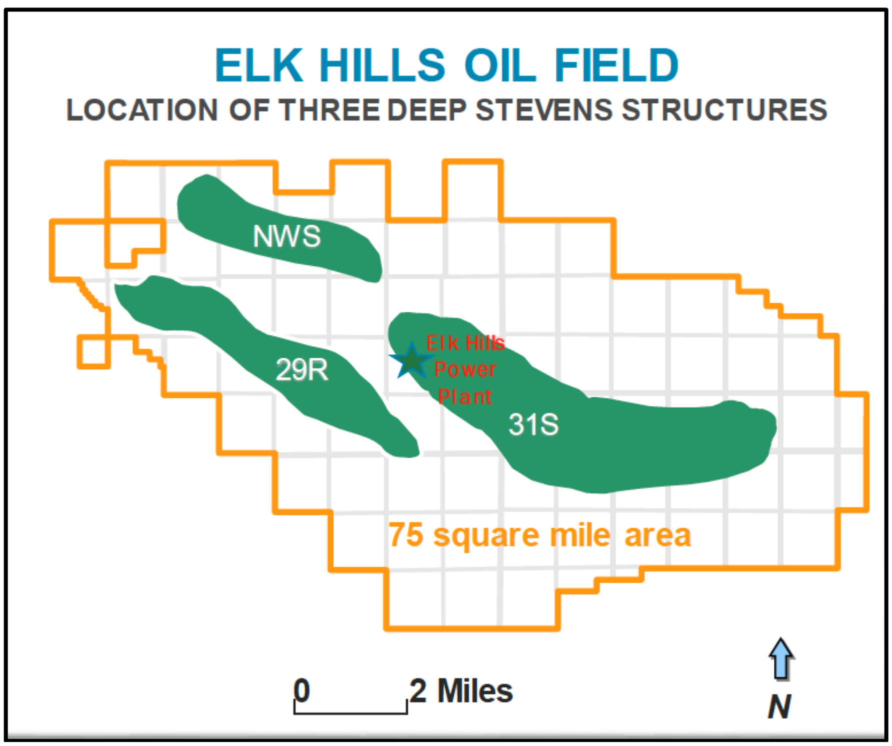

Figure 3-4. Location of Elk Hills Power Plant within the Elk Hills Oil Field

[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.

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[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.

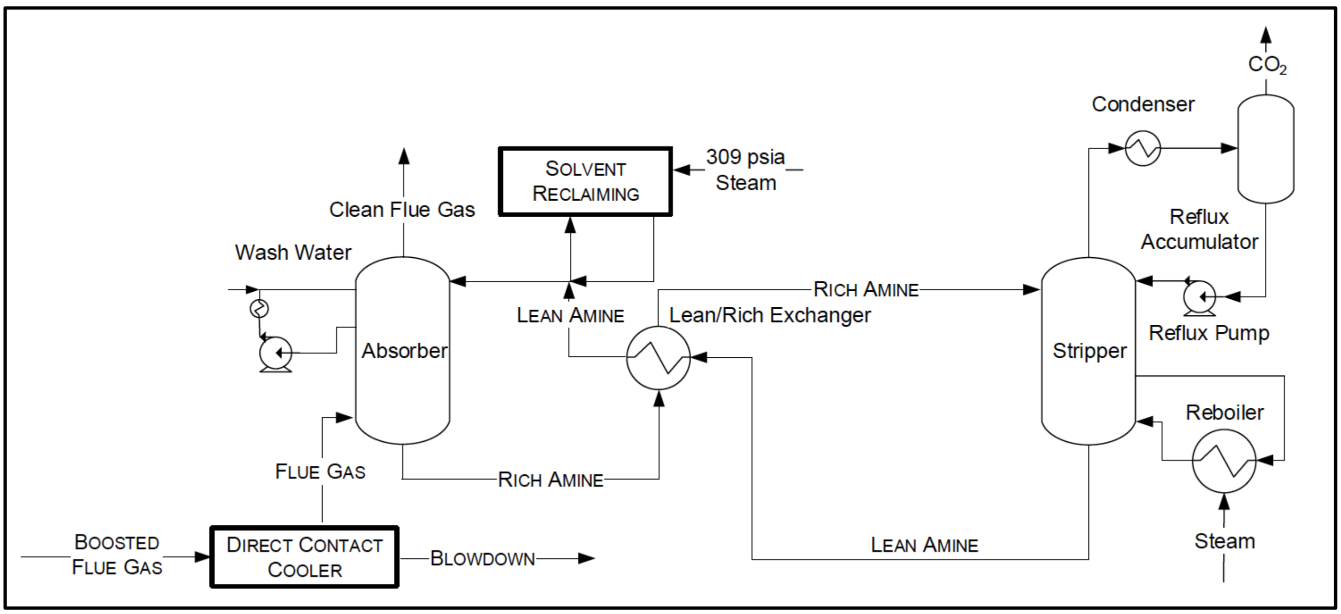

Figure 3-5. Simplified Block Flow Diagram: Cansolv CCUS to 550 $MW_{(n)}$ NGCC

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.

[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.

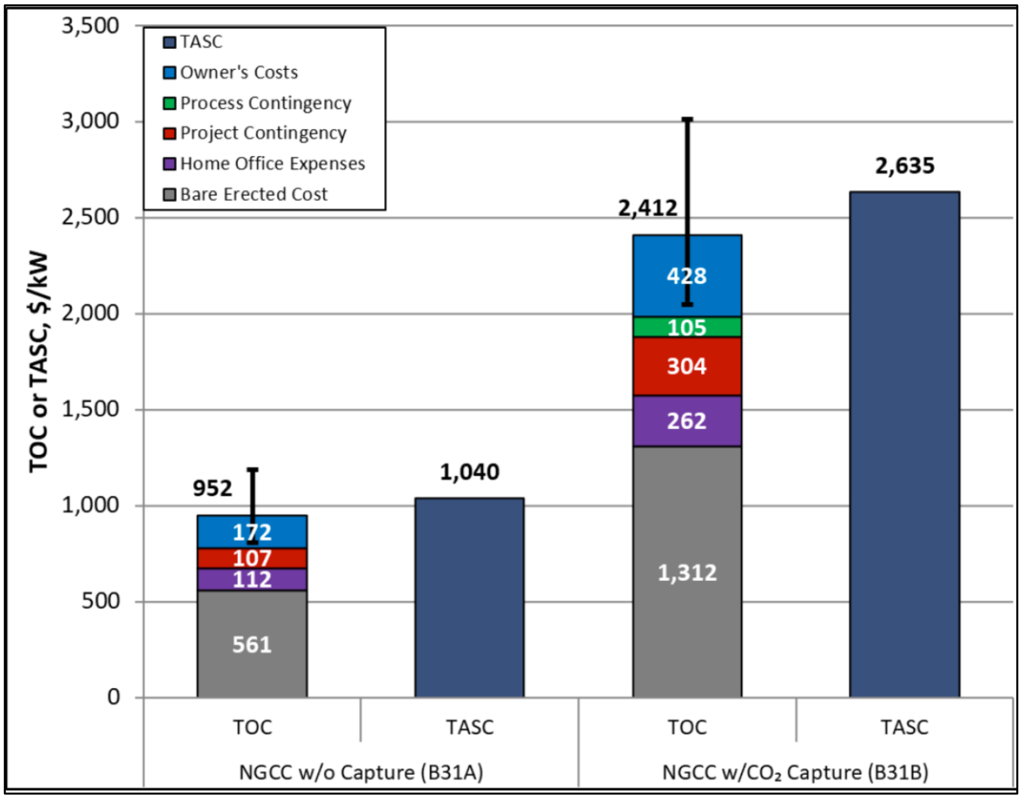

Figure 3-6. Capital Cost for DOE/NETL Reference Study: NGCC Application

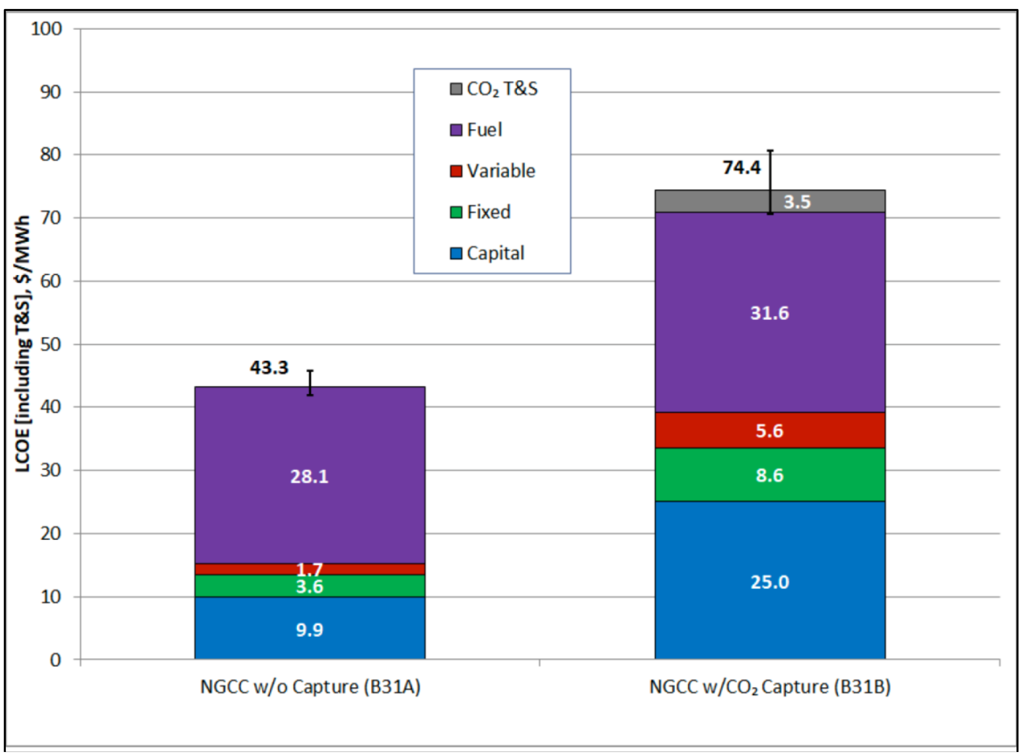

Figure 3-7. Cost Results for DOE/NETL Reference Study: Capital, LCOE

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.

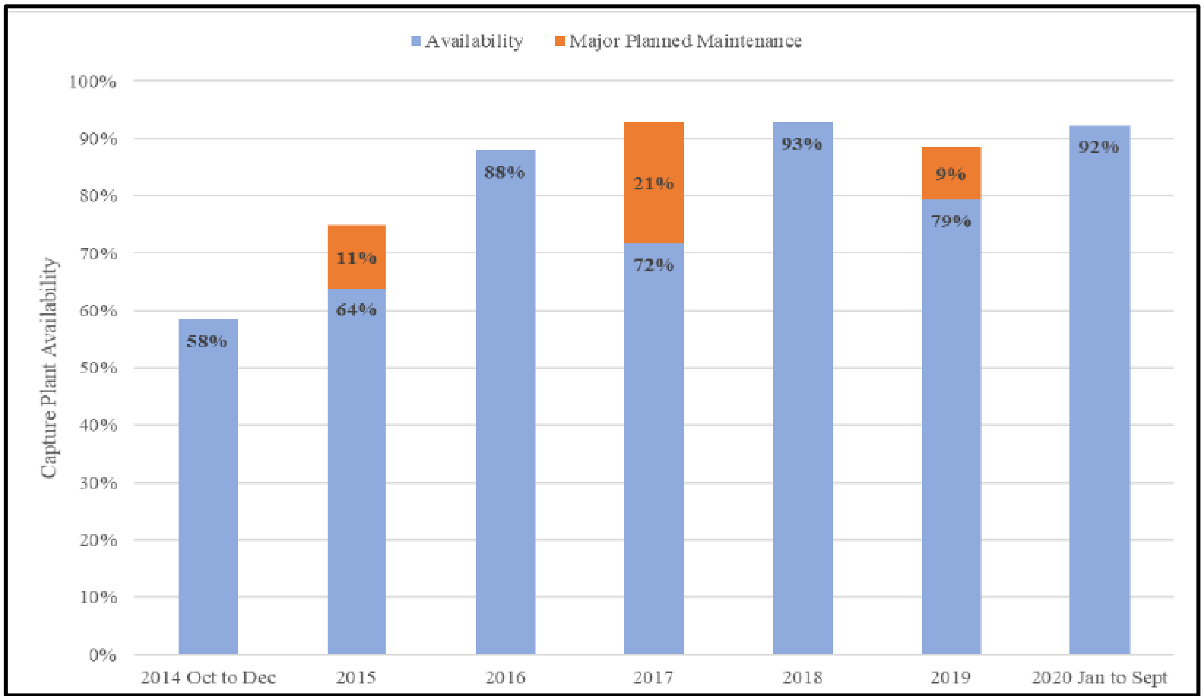
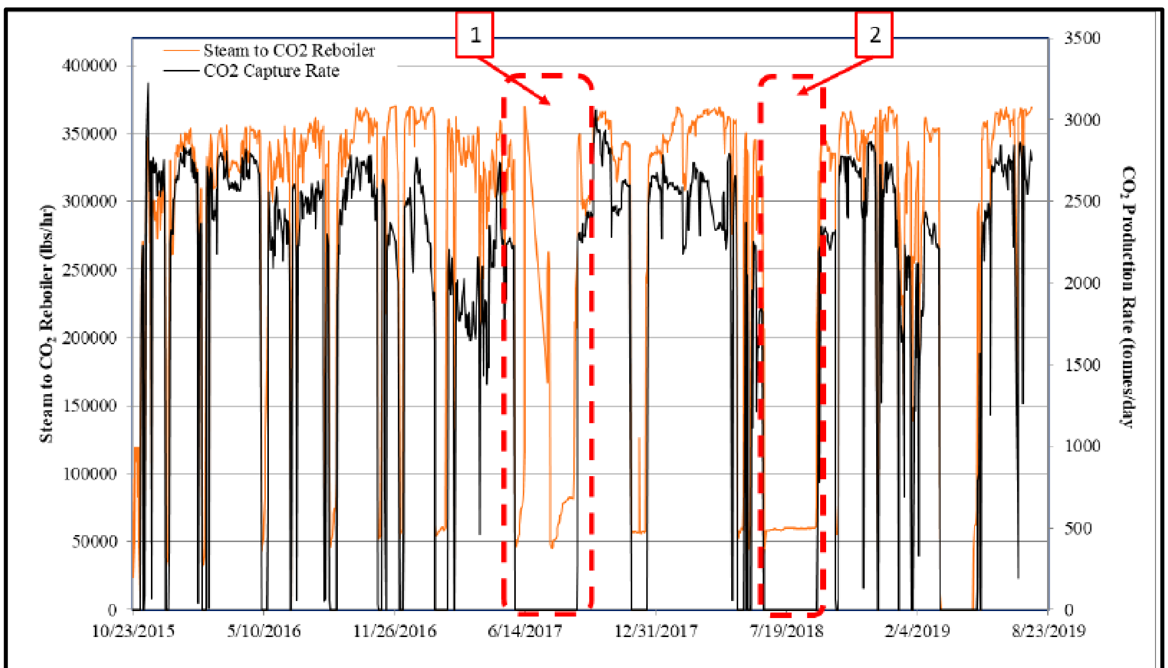


Figure 4-1. Boundary Dam Unit 3 CCS Process Availability: 2014 through Mid-2020



1. Planned Outage, Summer 2017
2. Adverse weather resulting in power plant turbine trip, Summer 2018

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]

Summary. 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.

[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.

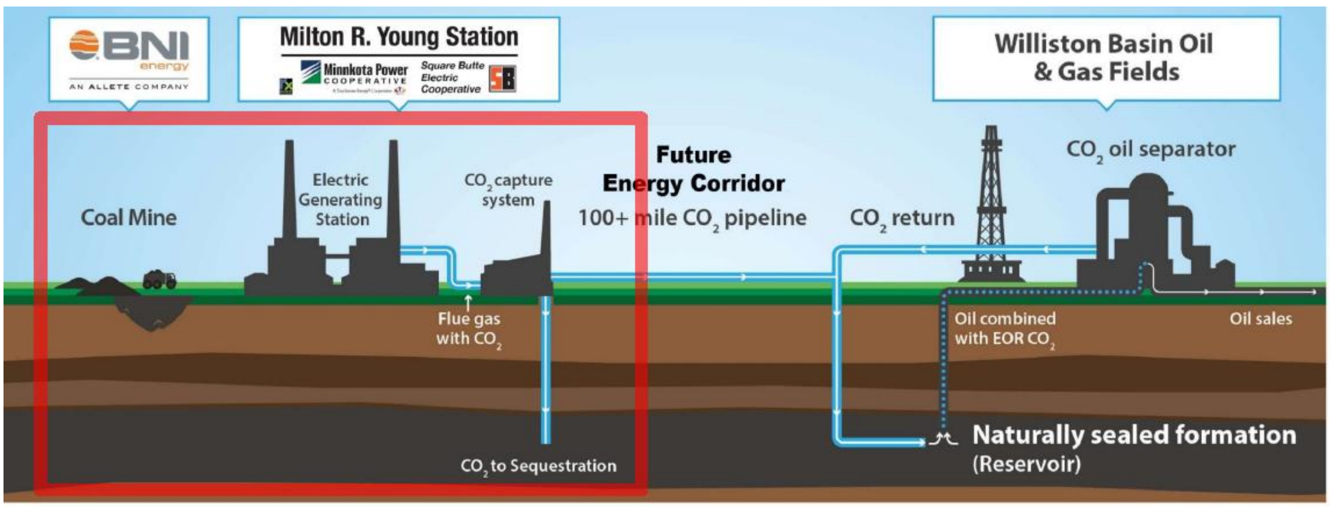

Figure 4-3. Milton R. Young Generating Station: Proximity to Sequestration Site, EOR

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]

Summary. 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.

[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.

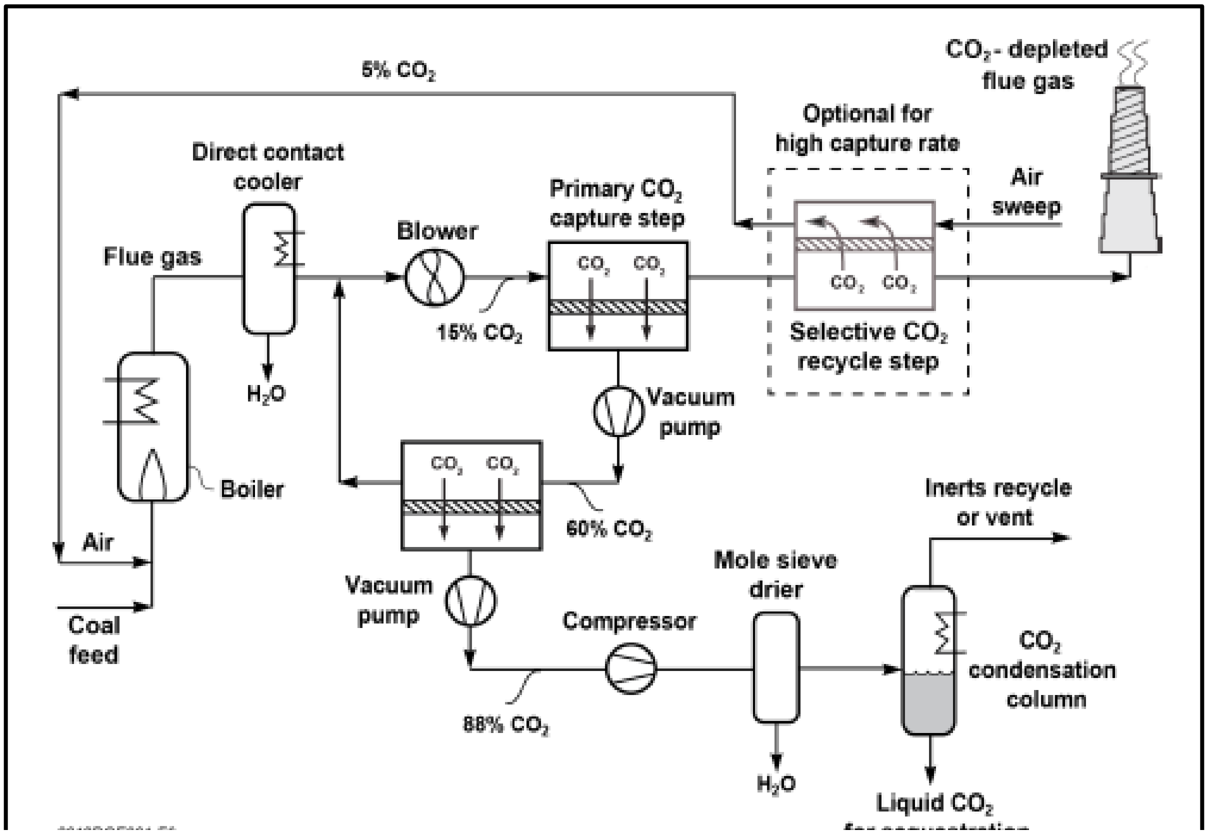

Figure 4-4. Flow Schematic: MTR Gas Separation Membrane

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.

Summary. 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.

[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.

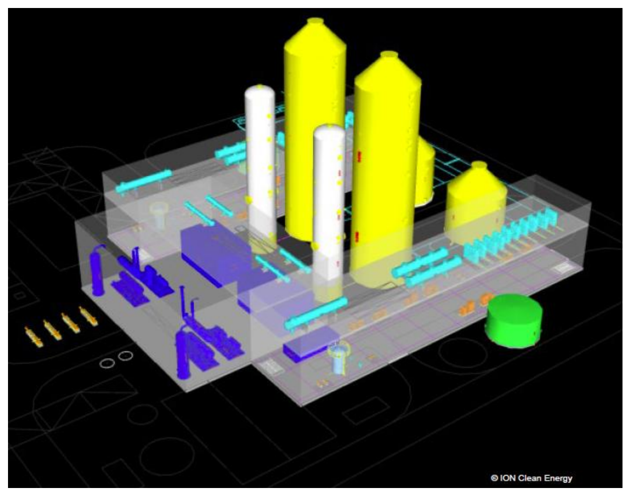

Figure 4-5. Gerald Gentleman Capture Island "Footprint" and CAD Depiction

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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.

[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.

<u>Summary</u>. 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.

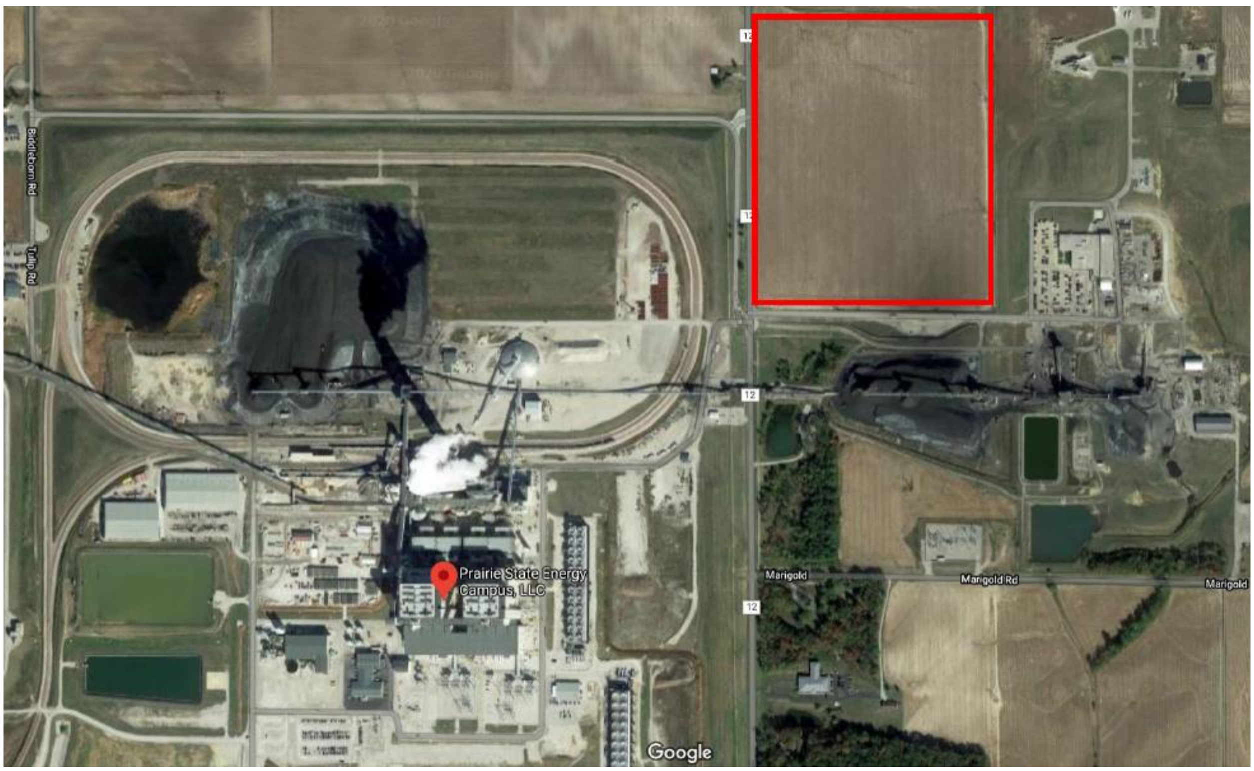

Figure 4-6. Prairie State Generating Station Unit 2 with Footprint for CO_2 Capture Island

[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.

[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.

<u>Summary</u>. 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.

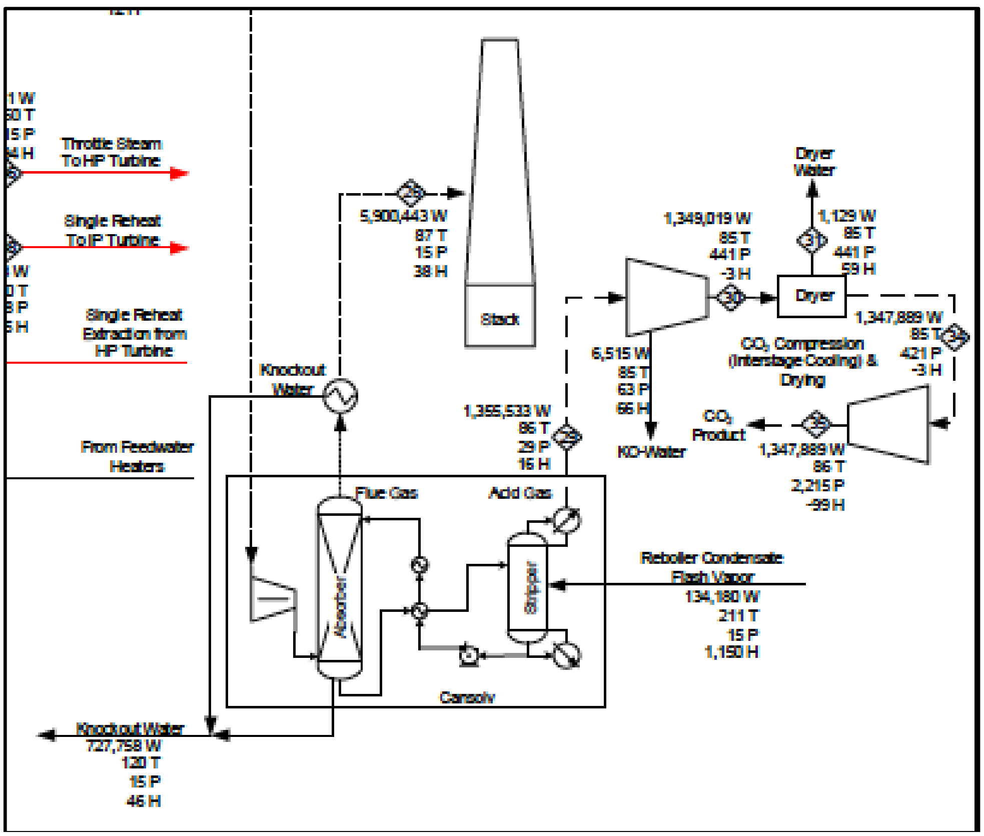

Figure 4-8. Flow Diagram: Cansolv CCUS to 650 $MW_{(n)}$ Subcritical Pulverized Coal Unit

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.

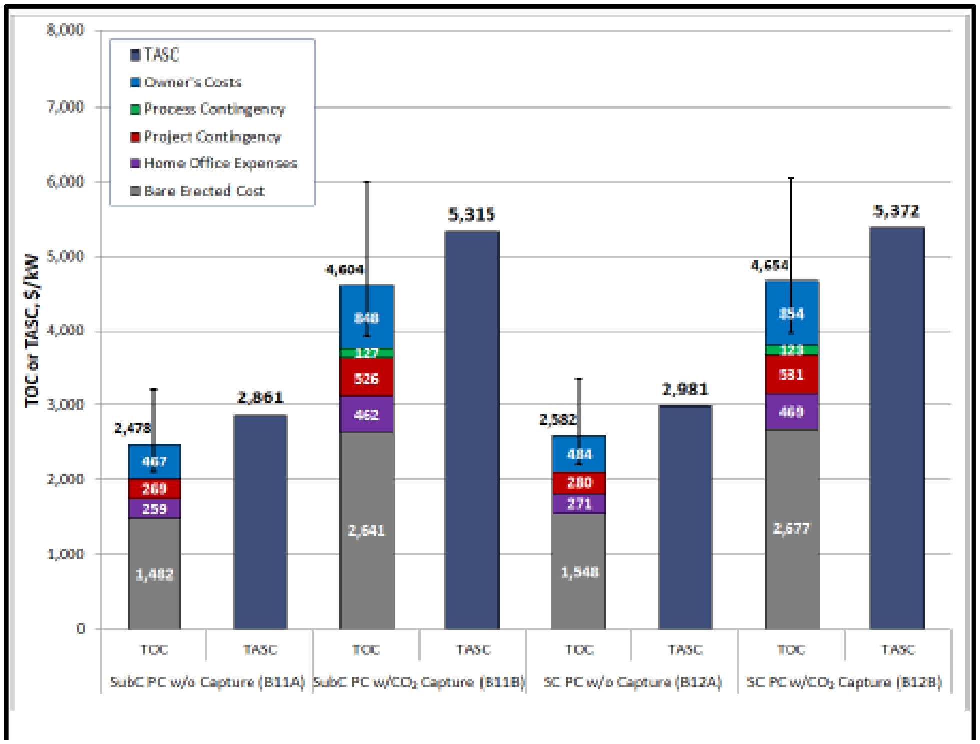

Figure 4-9. Capital Cost for DOE/NETL Reference Subcritical and Supercritical PC Study

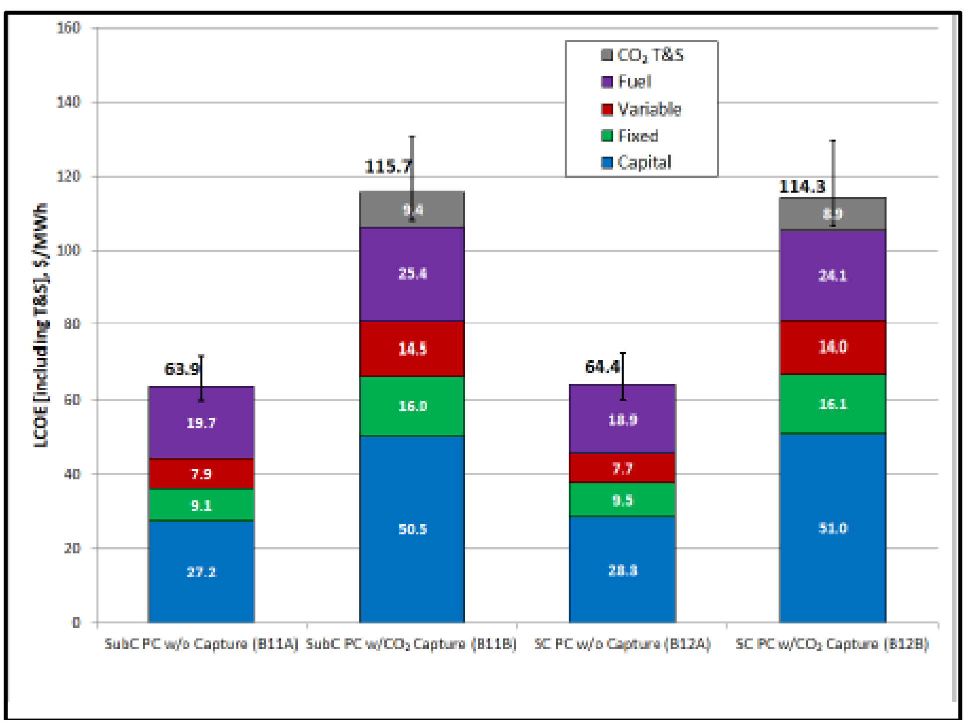

Figure 4-10. Levelized Cost for DOE/NETL Reference Subcritical, Supercritical PC Study

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.

[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.

[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.

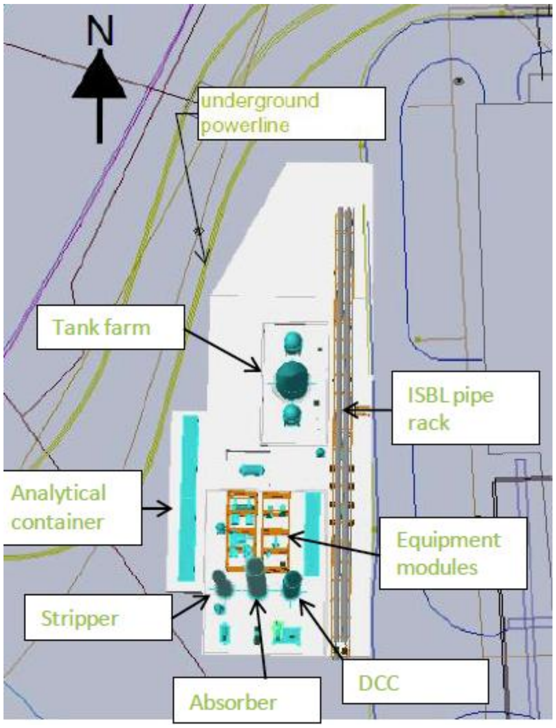

Figure 5-1. Plot Plan of CWLP Second Generation Absorbent Pilot Plant

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.

[112] See: https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

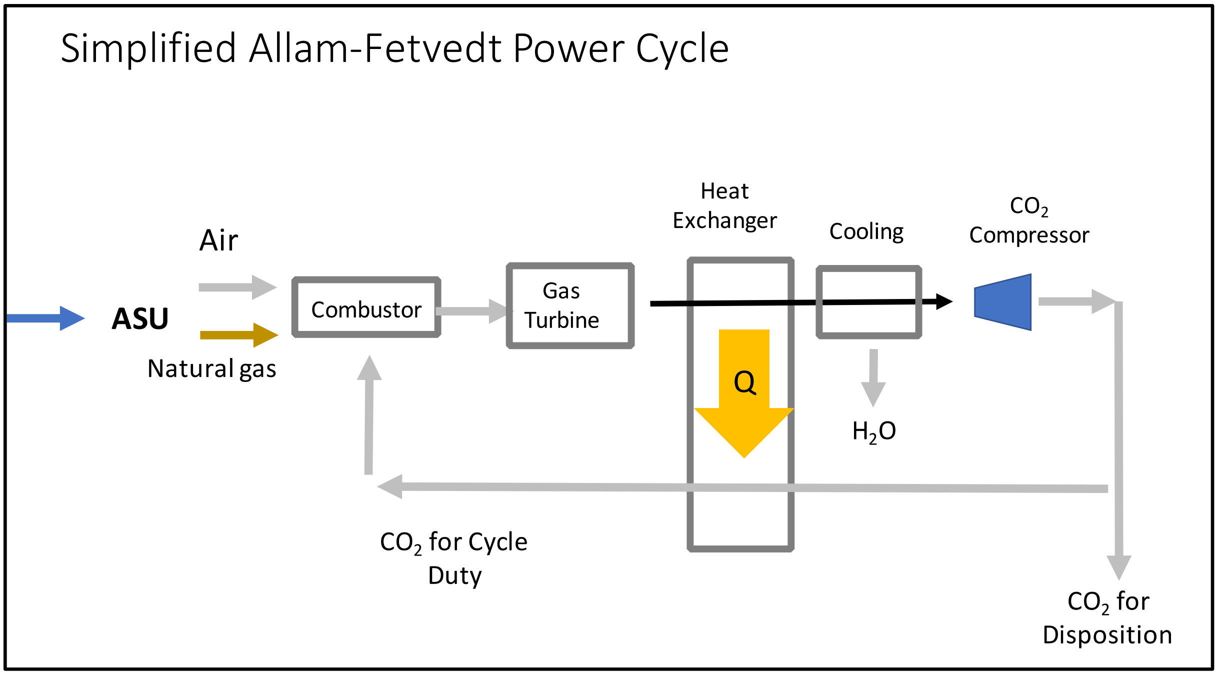

Figure 5-2. Simplified Allam-Fetvedt Cycle [113]

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.

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[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

[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.

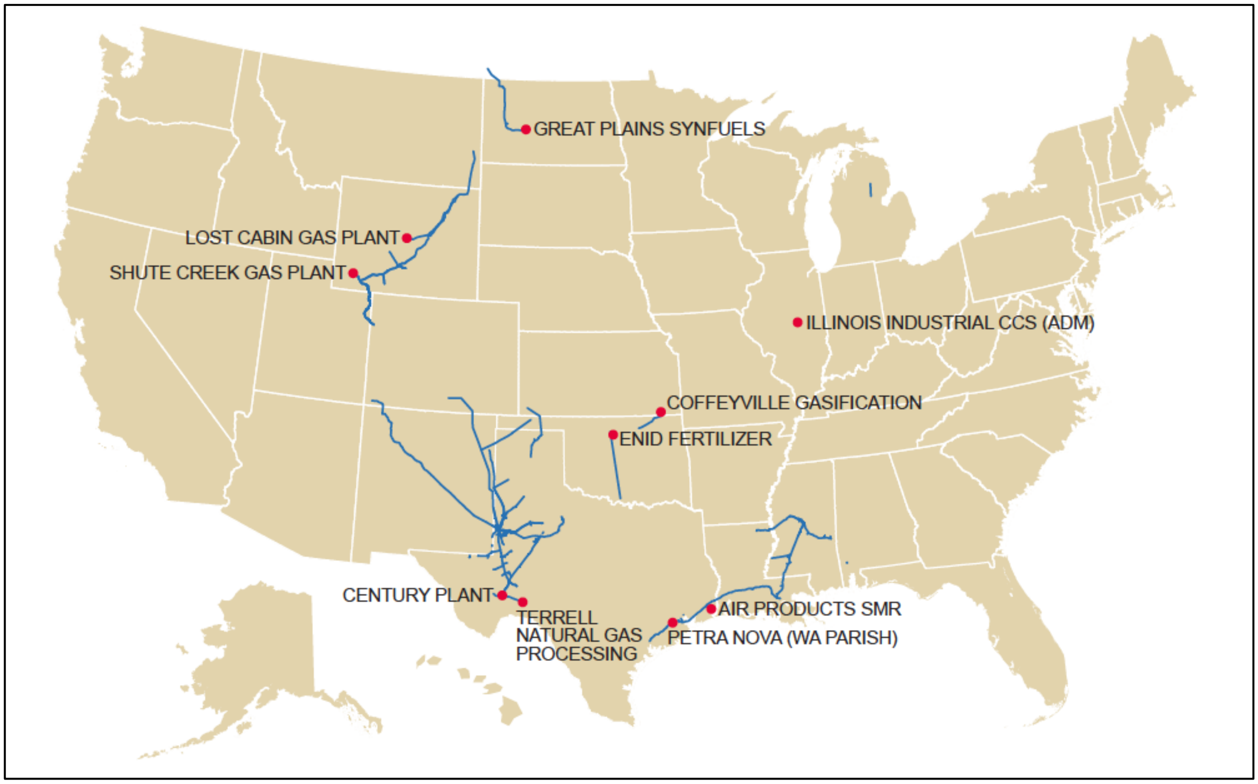

Figure 6-1. Routing of Major CO_2 Pipelines in U.S.[127]

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.

[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.

[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.

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[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.

[144] IEA 2015 CO_2 EOR and Storage.
[145] 2015 DOE/NETL Storage Atlas. Graphic 17.

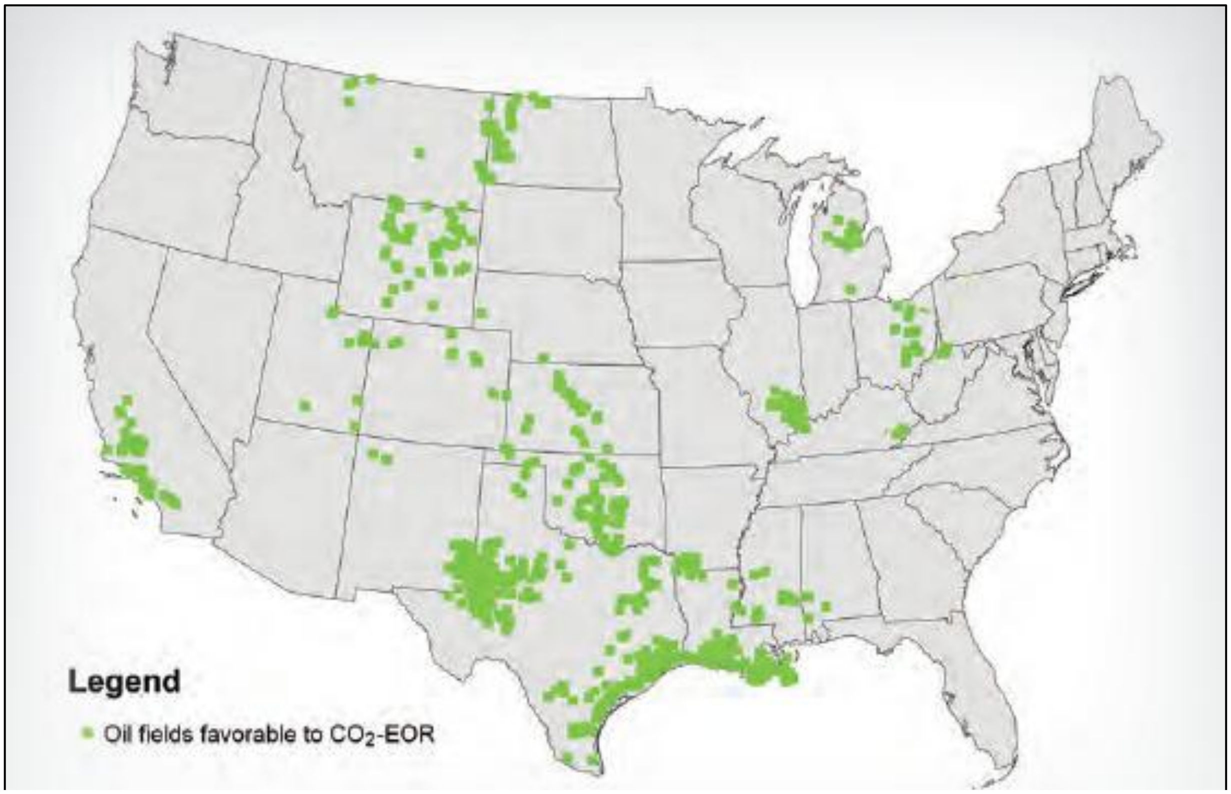

Figure 7-1. Major Oil Fields in the U.S. Identified as Favorable to EOR

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:

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[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.

[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/CO_2/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.

[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.

Kemper County.[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.

Wyoming CarbonSAFE Storage Complex.[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.

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[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.

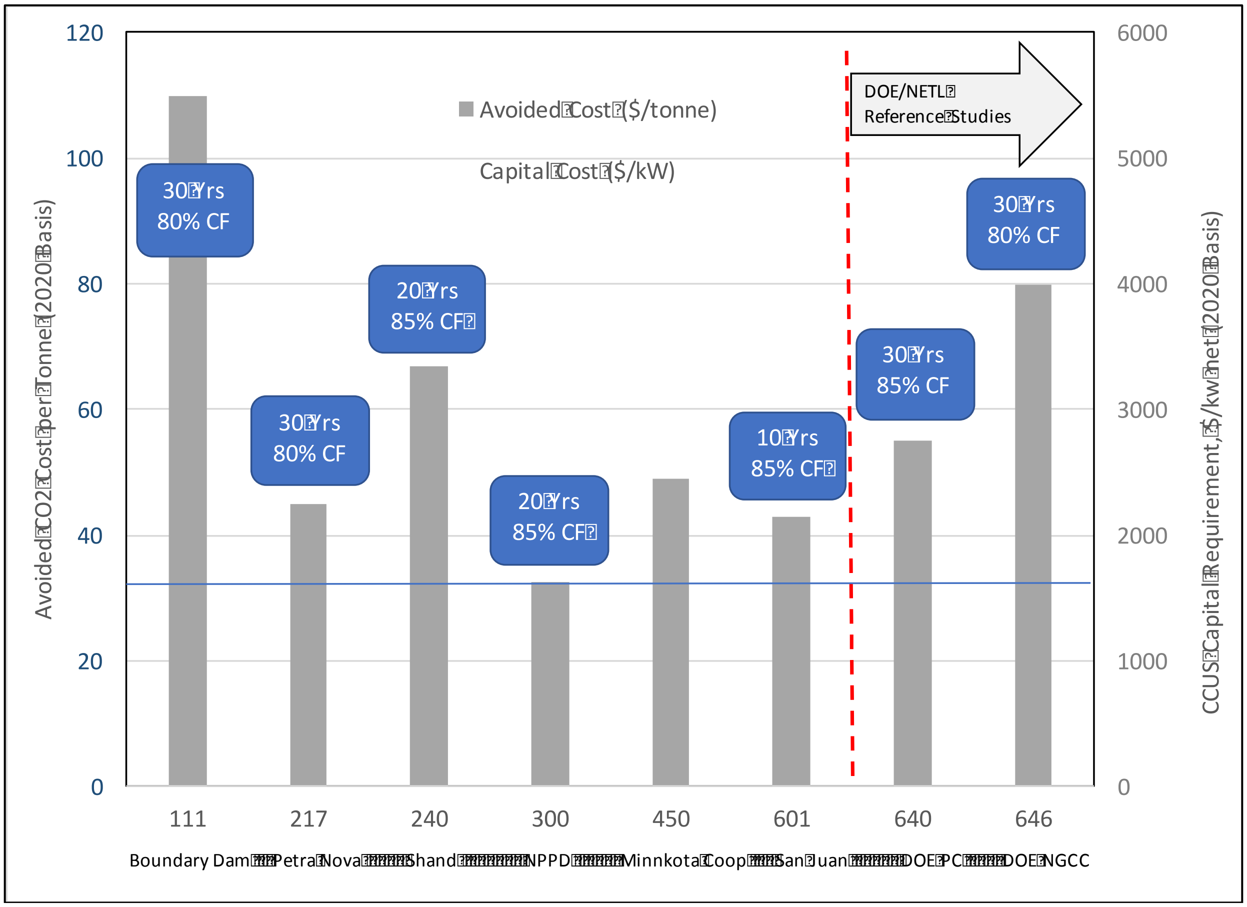

Figure 9-1. Capital Cost, Avoided CO_2 Cost per Facility Lifetime, Capacity Factor

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:

[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

<u>NGCC</u>. 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.

<u>Pulverized Coal</u>. 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]

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[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.