# Analysis of Carbon Capture Utilization and Sequestration Technology As BSER Under the 2024 Greenhouse Gas (GHG) and New Source Performance Standards for Fossil-Fired EGUs

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# 1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants.

This report supplements technical comments submitted in the docket of the proposed 2023 GHG NSPS rulemaking.[2] Since the submission of the 2023 report, several references have become available, among these submissions by SaskPower regarding Boundary Dam Unit 4, additional capital cost from a completed Front End Engineering Design (FEED) study, and an update of $CO_2$ pipeline permits in several states.

This report addresses five topics. Section 2 describes how experience with carbon capture utilization and storage (CCUS) at industrial scale does not reflect utility duty, as most industrial applications deploy CCUS as a slipstream of the source rather than integrated for 24x7 duty over the load cycle. Section 2 discusses how slipstream duty provides flexibility to avoid or minimize complications due to load following – and highlights that utility applications at Petra Nova and – to a lesser extent – SaskPower Boundary Dam Unit 4 function as a slipstream.

Section 3 summarizes detailed studies of CCUS applications. Ten such FEED studies for coal-fired and nine for natural gas/combined cycle (NGCC) firing are identified, denoting those completed and results in the public domain. Although many FEED studies are in progress and their results have not been released, there are no definitive, funded CCUS demonstration projects underway.

Section 4 of the report explores the operating experience of SaskPower Boundary Dam Unit 4, which is re-evaluated, considering information submitted by the project operator that had not been previously disclosed. New information shows Boundary Dam Unit 4 CCUS enjoyed a flexibility in duty that would not qualify as a commercial demonstration in the context of the proposed GHG rule. Similarly, the Petra Nova experience is re-assessed in this manner.

Section 5 discusses the capital cost estimates of CCUS processes, updated to include one additional coal-fired unit not available in August 2023, and with costs for all studies presented in the same cost year (2022). These results show the capital cost for CCUS, as applied to either coal-fired or NGCC generation, require as much or more capital than necessary for a new, greenfield state-of-the-art coal-fired or NGCC generating asset without CCUS.

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[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] E. Cichanowicz & M. Hein, Technical Comments on the Carbon Capture Utilization and Sequestration Aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule, August 7, 2023. Hereafter 2023 Technical Comments.

Section 6 presents an update of the permitting activities for $CO_2$ pipelines in the Midwest, summarizing the recent permit denials and project cancellation for Navigator Ventures, and permit denial for Wolf Carbon Solutions. In contrast, the Summit pipeline has secured permits in Iowa, North Dakota, and Minnesota, but continues to experience resistance and permit rejection in South Dakota. Summit has indicated its intent to continue to pursue access in South Dakota by altering pipeline routing to minimize barriers.

Cumulatively, these five topics, upon being revisited with recent information, further support the conclusion that CCUS for either coal-fired or NGCC application is not commercially demonstrated.

## 2 Discussion of Relevant Reference Cases

The 2024 Carbon Pollution Standard (CPS) designated CCUS as the best system of emission reduction (BSER) based on, among other factors, experience with industrial applications. There are two means in which CCUS currently applied on industrial sites fails to reflect utility operation –the process equipment is typically arranged differently and operates as a "slipstream" from the host unit, in contrast to an integrated operating mode.

Two EPA references cited in the 2023 proposed rule – Sears Valley Minerals and Bellingham Energy Center –deploy CCUS as a slipstream.[3]

- Sears Valley Minerals. The Sears site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[4] Public information suggests $CO_2$ capture is either intermittent or well below 90%, and the arrangement of three boilers suggests the CCUS process is configured as a "slipstream" that can be bypassed or deployed as needed.[5,6]

- Bellingham Energy Center. In the case of the 386 MW Bellingham facility, a DOE "fact sheet" reports $CO_2$ removal capability of 800 tons per day[7] as a slipstream.[8] The "fact sheet" suggests the unit operated from 1991 through 2005, with $CO_2$ removal of "85-95%".[9] The Bellingham gas flow rate – not specified in the literature – by linked to a 40 MW gas turbine is approximately 280 lb/sec (e.g. GE LM6000), or 1/6$^{th}$ of the approximately 1,700 lb/sec processed by a state-of-the-art J- or H- Class Frame turbine.

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[3] 88 Fed. Reg. 33,240, 33,292 (May 23, 2023).
[4] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.
[5] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[6] Specifically, if the $CO_2$ removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of $CO_2$ per day – and daily $CO_2$ removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% $CO_2$ removal for 35% operating time (perhaps one "daytime" shift).
[7] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[8] Specifically, if the $CO_2$ removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of $CO_2$ per day – and daily $CO_2$ removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% $CO_2$ removal for 35% operating time (perhaps one "daytime" shift).
[9] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

Operating CCUS or any environmental control process as a "slipstream" of gas, in contrast to being inseparably linked to the host unit, provides flexibility to manage uncertainties. A slipstream of gas flow can be operated independently of changes to the host unit. This feature enables the environmental control process to avoid issues with load ramping up or down, startup/shutdown, or process "upsets". The ability to maintain a constant gas flow rate isolates the process from these changes – process equipment can be taken off-line during startup/shutdown events, and activated only during well-controlled flow conditions.

Figure 2-1 is instructive on this topic. The figure presents a 3-dimensional model of the CCUS facility designed as a retrofit to Alabama Power NGCC generating units – either Daniel 4 or Barry Unit 6.[10] Figure 2-1 denotes flue gas processing equipment in green and power generation equipment – gas turbines, heat recovery steam generators, and cooling towers - in blue.

Each of the key CCUS process steps is defined in Figure 2-1. The components process flue gas according to a characteristic residence time and gas pressure drop, the latter monitored and input for flue gas fan operation. These process steps are the (a) exhaust gas recirculation (EGR) direct contact cooler, (b) CCS direct contact cooler, (c) CCS absorber, (d) CCS stripper, and (e) CCS and EGR cooling towers.

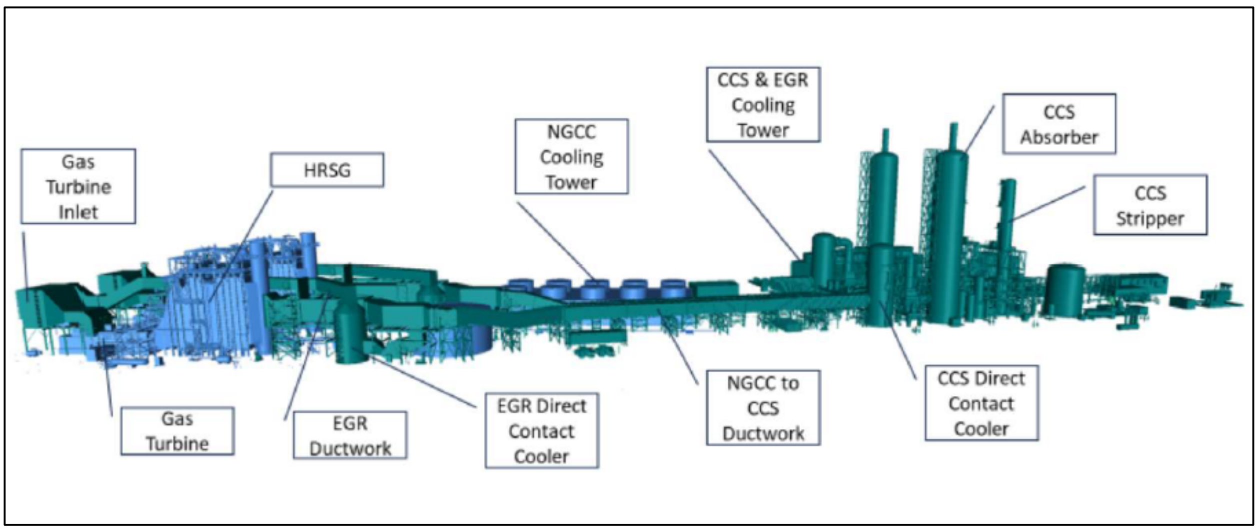


Figure 2-1. Arrangement of NGCC with CCUS Equipped with Exhaust Gas Recirculation

Further, the operation of each process step is determined by a series of subordinate actions, involving the consumption or production of liquid or gaseous media. Figure 2-2 presents a simplified process flow sheet of the carbon capture process for the arrangement in Figure 2-1.

[10] Retrofittable Advanced Combined Cycle Integration for Flexible Decarbonized Generation, presentation to the DOE Carbon Management Conference, August 6, 2024.

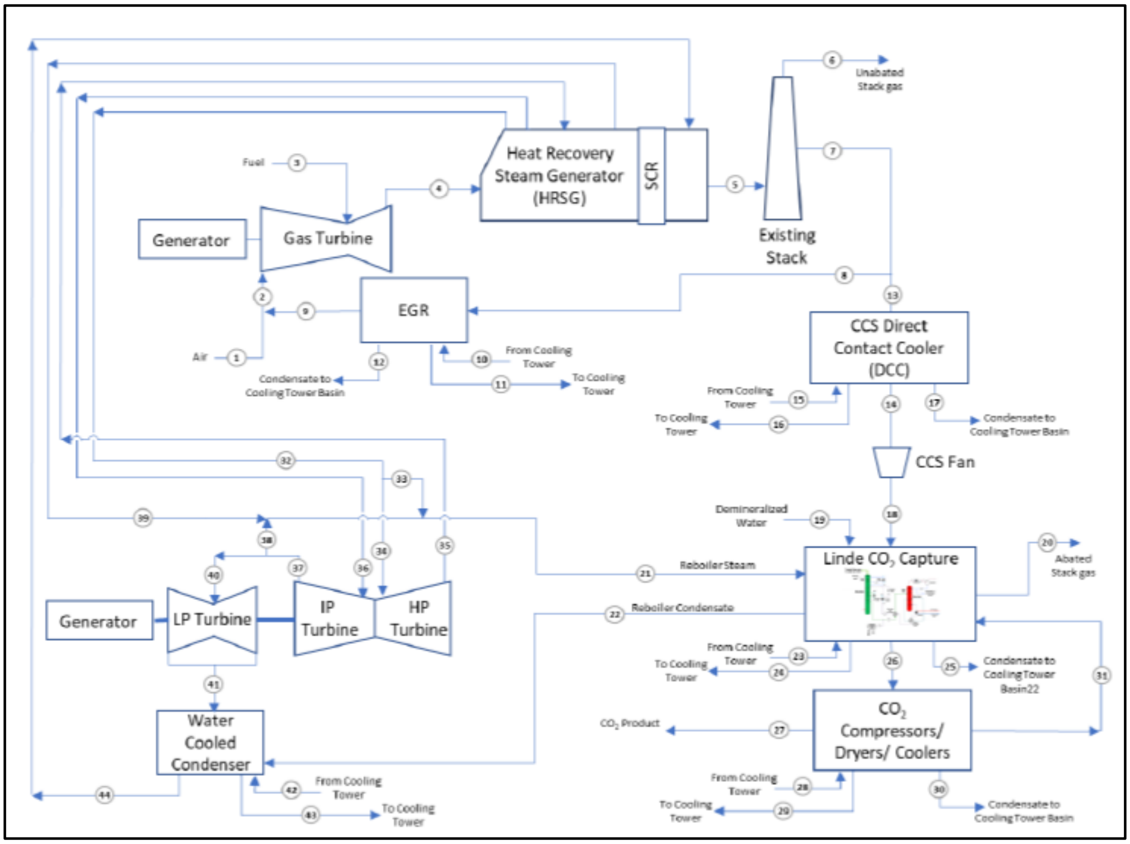


Figure 2-2. Simplified Process Flowsheet: CCUS Process Arrangement Daniel/Barry

As an example, the Linde $CO_2$ Capture step planned for potential application at Daniel 4 or Barry 6 is designed to process five input and four output flow streams. The five inputs streams are (a) flue gas for processing, (b) demineralized water, (c) reboiler steam for heating, (d) cooling tower effluent for cooling, and (e) partially processed amine streams containing $CO_2$. The four output steams are (f) condensate to the reboiler for heating, (g) process water to the cooling tower for cooling, (h) processed $CO_2$ for drying and compression, and (i) effluent flue gas for discharge. Each of these input and output streams operate in a dynamic manner, changing with host unit load, $CO_2$ concentration, and ambient temperature. Coordination of the steam supply and the flow rate of the liquid amine sorbent that removes $CO_2$ are key subordinate inputs important to process operation.

For CCUS units integrated 24 x 7 with a host boiler, process control systems must instruct these subordinate input and output flows to change with boiler operation. The characteristic time for some of the changes can be minutes or less.

Further, the mass rate of $CO_2$ production must be synchronized with the (not shown) steps for compression and delivery to the high-pressure pipeline.

The design challenge is ensuring process components—especially the $CO_2$ absorber and stripper—respond immediately to changing conditions rather than reacting to outdated data from 15-30 minutes earlier. Achieving such coordinated action is feasible– but rarely in a First-of-a-

Kind (FOAK) concept. Several iterations of the “nth” design will be required to be tested in authentic duty.

Conclusion: Experience with CCUS on an industrial process, or at utility demonstration with process duty on a flue gas “slipstream”, does not represent the dynamic actions required for 24 x 7 duty on a host utility boiler. Slipstream success does not imply full-scale utility power plant success.

# 3 Status of FEED Studies

The proposed rule reports that several planned CCUS installations on coal-fired units have been abandoned[11] or faced challenge as to feasibility, after completion of FEED studies. Section 3 summarizes publicly available results from FEED studies and reports on project status.

The FEED study is a key CCUS decision metric. FEED studies (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the critical components to the site. EPA rightfully identifies these FEED studies as "…projects in the early stages of assessing the merits of retrofitting coal steam EGUs with CCS technology", with potential for "…the application of CCS to existing gas facilities".[12]

The follow-on to a FEED study and precursor to a demonstration is a detailed "Specification" study, which defines equipment attributes, layout, and an operating plan. These results are used to develop a request for proposal to solicit from a supplier a "firm" process design and cost. This "Specification" step has been completed only for SaskPower Boundary Dam 3 and Petra Nova.

## 3.1 Coal-Fired FEED Studies

Table 3-1 lists ten FEED studies addressing coal-fired generation. Table 3-1 describes the host unit features, the $CO_2$ capture technology evaluated, the targeted $CO_2$ removal, and the fate of $CO_2$ (e.g., either enhanced oil recovery or storage). FEED studies for the first six projects are publicly available; none of these projects will advance to follow-on studies. As noted by EPA in the proposal, the FEED study for Cleco's Project Vault was abandoned in late 2024, and a key participant in Minnkota Power's Project Tundra similarly withdrew from further participation.[13]

FEED studies for the remaining sites are in various stages of planning and execution, starting with Springfield City Water Light & Power (CWL&P) securing funding for a study at Dallman Unit 4.[14] The FEED studies for Duke Energy Edwardsport and Navajo Transitional Energy Company are in progress and are anticipated to be released in 2026. Cost results from the six publicly available reports summarizing these FEED studies are presented in Section 4.

[11] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[12] Steam EGU TSD. P. 23.
[13] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[14] Brownstein, cc, Phase III Update: Large Pilot Testing of Linde-BASF Advanced Post-Combustion $CO_2$ Capture Technology at a Coal-Fired Power Plant, presented to FECM/NETL 2024 Carbon Management Research Project Meeting August 5, 2024.

Table 3-1. CCUS FEED Study Status: Coal-Fired Application

| Station/ Unit | Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam | Capture Technology: | $CO_2$ % Capture, MTs/h | $CO_2$ Fate |
|---|---|---|---|---|
| **Milton R. Young/ Minnkota Power Co-op** | 1: 250 MW (n)<br>2: 470 MW (n)<br>Note: "net" basis prior to CCUS | Econamine FG$^+$ | 90% target (11,000 MT/d) | Storage in saline reservoir, or EOR |
| **Dry Fork/ Basin Electric** | 440(n) prior to CCUS | MTR Polaris membrane | 70% target | "Carbon Valley" hub: Saline storage, EOR |
| **NPPD: Gerald Gentleman** | 700 MW (2 x 350 MW)<br>642 MW w/CCUS | Ion Clean Energy solvent | 90%, or 638K lbs/h (2.2 M MT/y) | EOR |
| **Enchant Energy/San Juan 1-4** | U1: 370 (n)<br>U4: 507 (n) | MHI amine solvent | 90% | Storage, with EOR to Permian Basin alternate |
| **Prairie State Generating Company** | 816 (g)<br>Aux power: 85.5 MW | MHI KM-CDR | 95%, 8.46 MT /y | Off-site saline storage |
| **SaskPower Shand** | 305(g)<br>279 (n) | KM CDR Process | 90% | EOR at Weyburn, Midale |
| **Cleco Power Madison Unit 3** | 605 MW(n)<br>(CFB boiler, 70/30 pet coke/Illinois coal) | MHI amine solvent | 95% | Storage in geologic formations |
| **Duke Edwardsport** | 618 MW IGCC | Honeywell Advanced Solvent | 95% | Storage on-site in geologic formations |
| **Navajo Transitional Energy/Four Corners** | 1,500 MW Four Corners Station | MHI amine solvent | 95% (10 million Mtons/y | EOR or Saline Storage |
| **CWL&P Dallman U 4** | 200 MW | Linde/BASE Solvent | TBD | Storage in Illinois Basin |

## 3.2 Combined Cycle

Table 3-2 lists nine FEED studies addressing NGCC generation. Similar to the case for coal, Table 3-2 describes the host unit features, the $CO_2$ capture technology evaluated, the targeted $CO_2$ removal, and the fate of $CO_2$ (e.g., either enhanced oil recovery or storage).

Table 3-2. CCUS FEED Study Status: NGCC Application

| Station/ Unit | Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam | Capture Technology: | $CO_2$ % Capture, MTs/h | $CO_2$ Fate |
|---|---|---|---|---|
| **Golden Spread/ Mustang** | 480 (n), w/o CCUS<br>399 (n) w/CCUS<br>(2 x 2 x 1)<br>Steam: aux boiler | 2$^{nd}$ gen solvent (piperazine) | 90%<br>190 MT/h | EOR |
| **Rayburn Energy** | 594(n) w/o CCUS<br>460 (n) w/ CCUS<br>(2 x 2 x 1)<br>Steam: turbine | Generic MEA conventional absorber/ stripper | 85%<br>129 MT/h | Primary: saline fields.<br>Secondary: local EOR. |
| **Elk Hills** | 550(n) w/o CCUS<br>515 (n) w/CCUS<br>2 x 2 x 1 (w/duct-firing)<br>Steam: aux boiler | Econamine FG Plus$^{+}$ | 90% of total effluent (74% $CO_2$ aggregate or 167 MT/h | Storage below the plant site |
| **Daniel 4** | 529(n) w/o CCUS<br>450 (n) w/CCUS<br>(2 x 2 x 1)<br>Steam: turbine | Linde-BASF OASE® blue solvent | 90% | Saline storage at Kemper County, MS |
| **Barry 6** | 525(n) w/o CCUS<br>446 (n) w/CCUS<br>(2 x 2 x 1)<br>Steam: TBD | Linde-BASF OASE® blue solvent- EGR to elevate $CO_2$. | 95+%<br>MTs removal TBD | Same as Daniel 4 |
| **Calpine Deer Park (5 units)** | 5x180 CT + 1 Steam. (n) w/o CCUS (1,175 MW). CCUS aux power 75 MW. | Shell Cansolv (2$^{nd}$ Generation) | 95%<br>~600 MT/h (6.5 MT/yr) | Storage at Gulf Coast sites |
| **Calpine Delta Energy Center** | 857 MW (3 x 3 x 1)<br>3 Siemens W501F, 3 Deltak HRSGs, Toshiba Turbine | Ion Clean Energy Sorbent | 95% or 2.4 MTa | Storage |
| **TECO Polk Power Unit 2** | 1,168 MW (4x4x1) (Four GE 7FA turbines) | Ion Clean Energy Sorbent | 95% or 3 MTa | TBD |
| **LG&E Cane Run Unit 7** | 640 MW (n) Two Siemens SGT6-5000F turbines; 2 x 2 x 1 | University of Kentucky water-lean solvent | 95% | TBD |

Of the nine FEED studies in Table 2, five have been completed with results available in the public domain. The status of these FEED studies is as follows:

- Completed, results in the public domain, no further actions planned. Golden Spread, Rayburn Energy, and Elk Hills –

- Completed, results in public domain, further actions pending. Daniel 4 and Barry 6.

- Results in progress, not yet available for release. Calpine Deer Park and Delta,[15] Tamp Polk Power, LG&E/KU Cane Run – the latter anticipating a completion date in 2025 and results publicly available in 2026.

In summary, of nine FEED studies on NGCC, four are completed with no further actions planned; two completed, but further actions are pending results in progress. Four studies are in progress, with results not available, and plans are dependent on the study outcome.

These activities show interest in deploying CCUS to NGCC, but as conceptual exercises. Notably, there are no operating CCUS applications or definitive, funded plans for commercial deployment.

Conclusion. Of the nineteen FEED studies either completed or in progress, none have led to an actual, funded CCUS demonstration projects. Several such studies are in progress and are anticipated to be completed in 2026. To date, none are committed to a demonstration.

[15] https://www.calpine.com/carbon-capture-and-sequestration-ccs/feed-studies/.

# 4 North American Utility Scale Process Experience

The EPA in the 2024 rulemaking proposed both SaskPower Boundary Dam Unit 3 and the NRG Petra Nova project provided sufficient experience to enable CCUS to be designated "adequately demonstrated at a capture rate of 90%."[16] Both demonstrations provide experience but are inadequate to establish CCUS as demonstrated and commercially available.

Section 4 presents the status of these projects updated with recently available or revised information.

## 4.1 SaskPower Boundary Dam 3

SaskPower has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv $CO_2$ process. Inherent to the Cansolv process is an $SO_2$ removal step to limit emissions to less than 10 parts per million (ppm) that, combined with improved particulate matter control, protects the amine sorbent from degradation.

Operating details of this unit are summarized in a previous report.[17] Several days preceding the close of the comment period for the 2023 proposed rule SaskPower shared additional details of the Unit 3 CCUS design and operation,[18] some of which not previously released to the public. In their August 2, 2023, filing SaskPower noted:

- Amine Sorbent Compromise. As cited in earlier publications,[19,20] the amine-based sorbent that captures $CO_2$ is compromised by contamination of fly ash from the particulate collector, reducing $CO_2$ capture effectiveness. SaskPower concedes this shortcoming and notes that eight years of development were required to improve operations to a state not yet fully disclosed.[21]

- Reduced Flue Gas Processing Rate. The demonstration facility operates below full gas flow capacity, except for a brief multi-day period after startup. This reveals an undisclosed design margin in the process.

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[16] 89 Fed. Reg. 39,847 (May 9, 2024) (Final Rule).
[17] August 7, 2023 Technical Comments.
[18] SaskPower. Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule. August 4, 2023. Document ID No. EPA-HQ-OAR-2023-0072-0687. Hereafter SaskPower 2023 Correction.
[19] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability.*
[20] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility*
[21] SaskPower 2023 Correction.

- Slipstream Features. In a disclosure not previously shared or widely disseminated, Boundary Dam staff concede that a fraction of the flue gas from the Unit 3 boiler is not processed but bypassed – for purpose of reliability. The fraction of flue gas bypassed is 5% of total flow – or 58,325 actual cubic feet per minute (acfm) of the total 1,166,497 acfm.[22]

- $CO_2$ Optimized for 65-70% $CO_2$ Capture to Ensure a Higher Reliability. SaskPower does not describe what steps it takes to improve reliability at the expense of $CO_2$ capture. One likely means to do so is lowering the amine sorbent recirculation rate, which may be necessary depending on recirculation equipment reliability or a change in sorbent properties. This action can minimize reagent handling problems that could compromise reliable operation. A second means to compromise $CO_2$ removal to ensure high reliability is to reduce the volume of gas flow processed.

Each of these revelations - eight years after unit startup and numerous publications – document that additional work must be accomplished through numerous "N$^{th}$-of-a-kind" demonstration tests. The "takeaway" is that the Boundary Dam experience does not demonstrate $CO_2$ removal of 90%; rather that 65-70% $CO_2$ can be achieved with a caveat on reliability.

A graphic depiction of the reliability challenges addressed by SaskPower is the reported CCUS process availability, by quarter, since late 2022. These data – acquired from the SaskPower Boundary Dam blog – present the availability average per quarter, from Q2 2022 through 2Q 2025.[23] (Data from prior quarters is not reported in this manner and not available for comparison). Figure 4-1 shows the SaskPower target of 75% - their selection for their conditions – is typically met, but under the conditions that not all the flue gas is to be processed.

A CCUS process reliability of 90% is likely required to support a 90% $CO_2$ removal for the domestic U.S. coal-fired fleet. This GHG target – even under the conditions where all flue gas is not treated – is attained by Boundary Dam in 6 only of 13 quarters.

[22] 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.. Hereafter Giannaris 2023.
[23] https://www.saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q2-2025

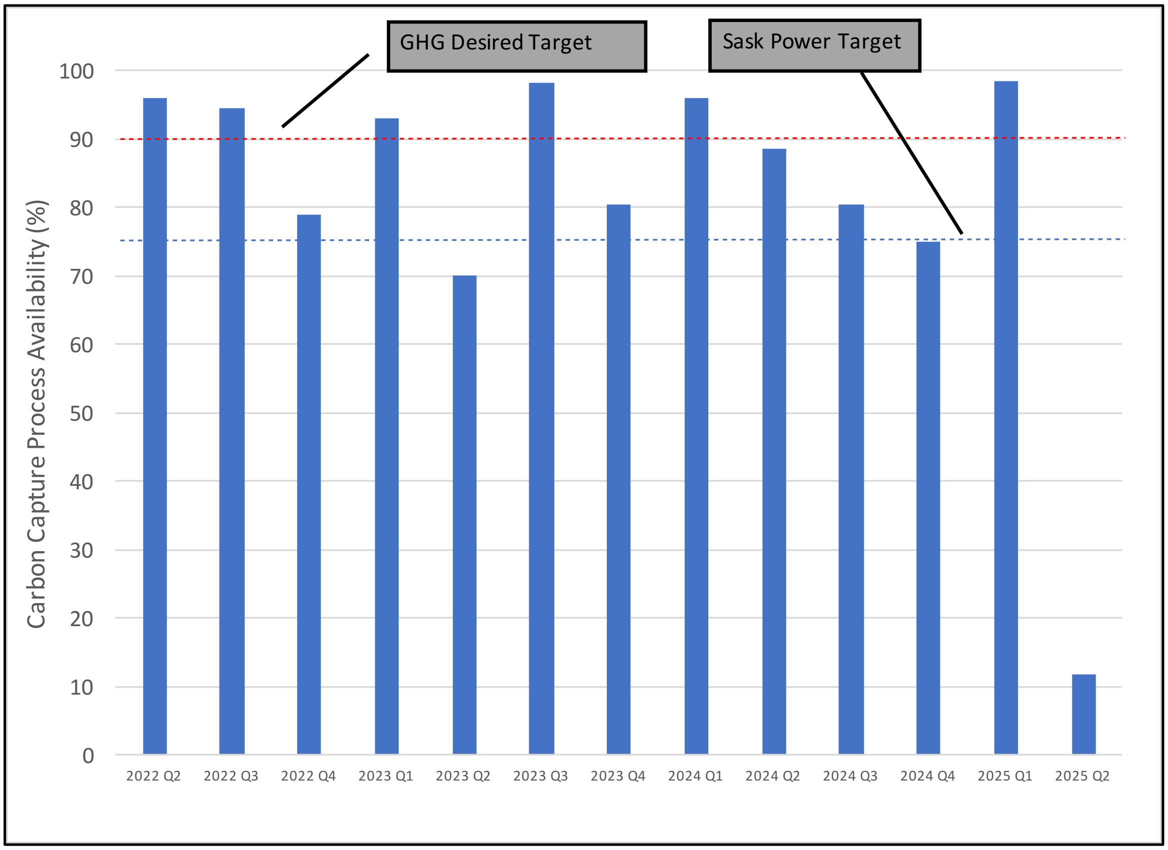


Figure 4-1. SaskPower Boundary Dam Unit 4 Carbon Capture Process Availability: 2002-2025

## 4.2 Petra Nova

NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. The operating details of this unit are reported in previous technical comments.[24]

Petra Nova operates as a slipstream process, in that a constant flow rate of flue gas is extracted from the host unit, regardless of the duty cycle of the host boiler. Petra Nova thus enjoys the same flexibility and advantage of the industrial applications at Searles and Bellingham and (as recently disclosed) Boundary Dam Unit 4. Consequently, the reported 92% $CO_2$ removal over the three years does not reflect actual, full-scale duty if integrated into the host boiler duty cycle.

Further invalidating Petra Nova as representative of actual, full-scale utility duty is the retrofit of the combined cycle generating unit to explicitly provide, via the HRSG, a reliable steam source for reagent regeneration. This constant, unchanging source of steam ensures available heat to regenerate $CO_2$ from the sorbent – regardless of the host unit's operations. Thus, some of the

[24] August 7, 2023 Technical Comments.

challenges of maintaining high $CO_2$ removal during unit variability such as load changes are eliminated.

Two limitations in the report—unchanged since August 2023—hinder transparent cost evaluation and levelized cost estimates per tonne of $CO_2$ removal. First, the combined cycle generator retrofit to provide reliable steam affects $CO_2$ capture economics, but detailed process costs aren't presented in the final report, making CCUS capital and operating cost assessment difficult. Second, the allocation of construction and balance-of-plant costs between the combined cycle and CCUS budgets remains unclear, as does the accounting of value from the additional gas turbine power generated and its impact on CCUS operating costs.

Most significantly, as noted in the August 2023 Comments, the actual cost-per-tonne of $CO_2$ removal during process operation has not been disclosed.

In summary, the design and operation of the Petra Nova process –on the surface successful in achieving the 90% $CO_2$ reduction – does not support the proposition that such $CO_2$ capture can be reliably broadly achieved.

Conclusion. The Boundary Dam Unit 4 and the Petra Nova CCUS demonstrations, although contributing significantly to the CCUS knowledge bases, do not adequately demonstrate CCUS for utility application. Boundary Dam Unit 4, after eight years of optimization, is limited to a $CO_2$ reduction target of 65-70% to assure high reliability. Petra Nova reliability benefits from coincident retrofit of a NGCC process and HRSG to reliably supply process steam. These conditions are unsatisfactory for broad CCUS deployment to the domestic fleet.

# 5 Update of CCUS Cost Estimates

Section 5 updates cost estimates for CCUS, incorporating an additional FEED study released since the August 2023 Technical Comments. As noted in Section 3, there are only two verified capital costs for CCUS – SaskPower Boundary Dam Unit 3 and Petra Nova (the shortcomings of the Petra Nova cost are discussed in the previous section). All other costs are estimates.

Figures 5-1 and 5-2 present CCUS capital cost *per net generating capacity after CCUS* for coal-fired and NGCC applications, respectively. A total of 12 cases are presented – eight addressing coal-fired duty and four addressing NGCC application. The costs are all reported in 2022 dollars. The coal-fired costs include SaskPower Boundary Dam 3 and Petra Nova results, in addition to the six FEED studies. NGCC applications include only four sites for which results are publicly available. For both categories, the cost of a new generation technology – subcritical pulverized coal and NGCC with triple reheat HRSG – is presented for comparison.

## 5.1 Coal Fired

Figure 5-1 presents CCUS cost as reported for SaskPower Boundary Dam Unit 4,[25] SaskPower Shand,[26] Petra Nova,[27] Basin Electric Dry Fork,[28] Minnkota Milton R. Young,[29] Enchant Energy San Juan,[30] Nebraska Public Power District Gerald Gentleman,[31] and Prairie State.[32]

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[25] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.
[26] Giannaris 2023.
[27] 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.
[28] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane $CO_2$ Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.
[29] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.
[30] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.
[31] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.
[32] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion $CO_2$ Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.

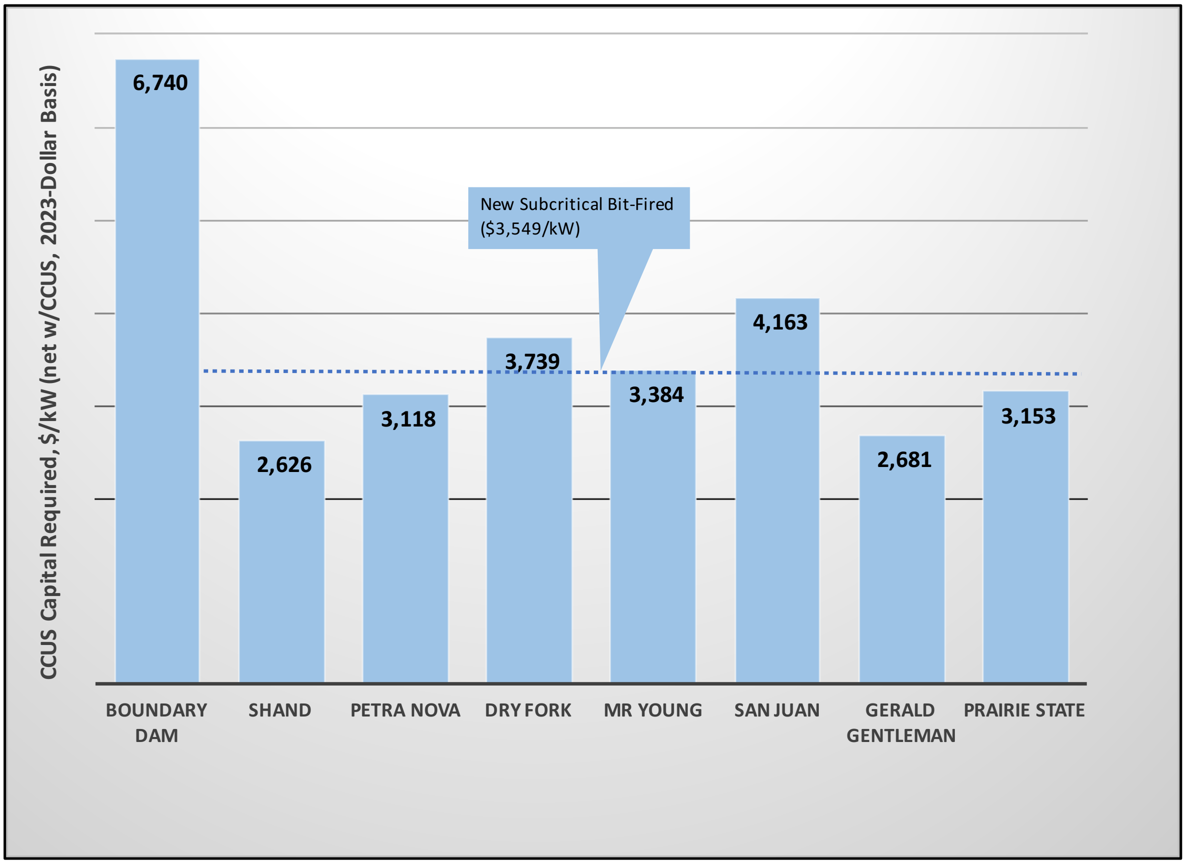

Figure 5-1. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 5-1 also reports capital cost for a hypothetical state-of-the-art subcritical coal-fired unit evaluated by the National Energy Technology Laboratory (NETL): 650 MW (net) with an 8,849 Btu/kWh net heat rate.[33]

Data in Figure 5-1 varies widely by site. Capital cost *per net generating capacity after CCUS* for four FEED studies is less than the cost for new coal-fired generation. In comparison, the CCUS cost for three FEED studies and Boundary Dam equals or exceeds that for new coal-fired generation. The Boundary Dam cost is atypical, given the "first-of-a-kind" status and relatively small generating capacity. An instructive cost metric to consider is the average of the FEED studies' cost results, excluding both Boundary Dam Unit 4 and the lowest of coal application (SaskPower Shand). These six cost estimates equate to $3,373/kW – almost identical to the cost of a new state-of-the-art subcritical coal-fired generator without CCUS.

It is important to recognize capital cost data in Figure 5-1 reflects only $CO_2$ capture, compression, and preparation for transport from the power station fence line. Capital and operating cost for $CO_2$ transport to the sequestration or EOR site, injection, and plume

[33] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

monitoring are not included. Sites requiring minimal pipeline length will still incur significant cost for the sequestration step.

## 5.2 NGCC Applications

Figure 5-2 presents the capital cost estimated by FEED studies of NGCC applications reported in the public domain. These FEED studies address the Panda Sherman,[34] Golden Spread Mustang,[35] Daniel 4,[36] and Elk Hills[37] generating units.

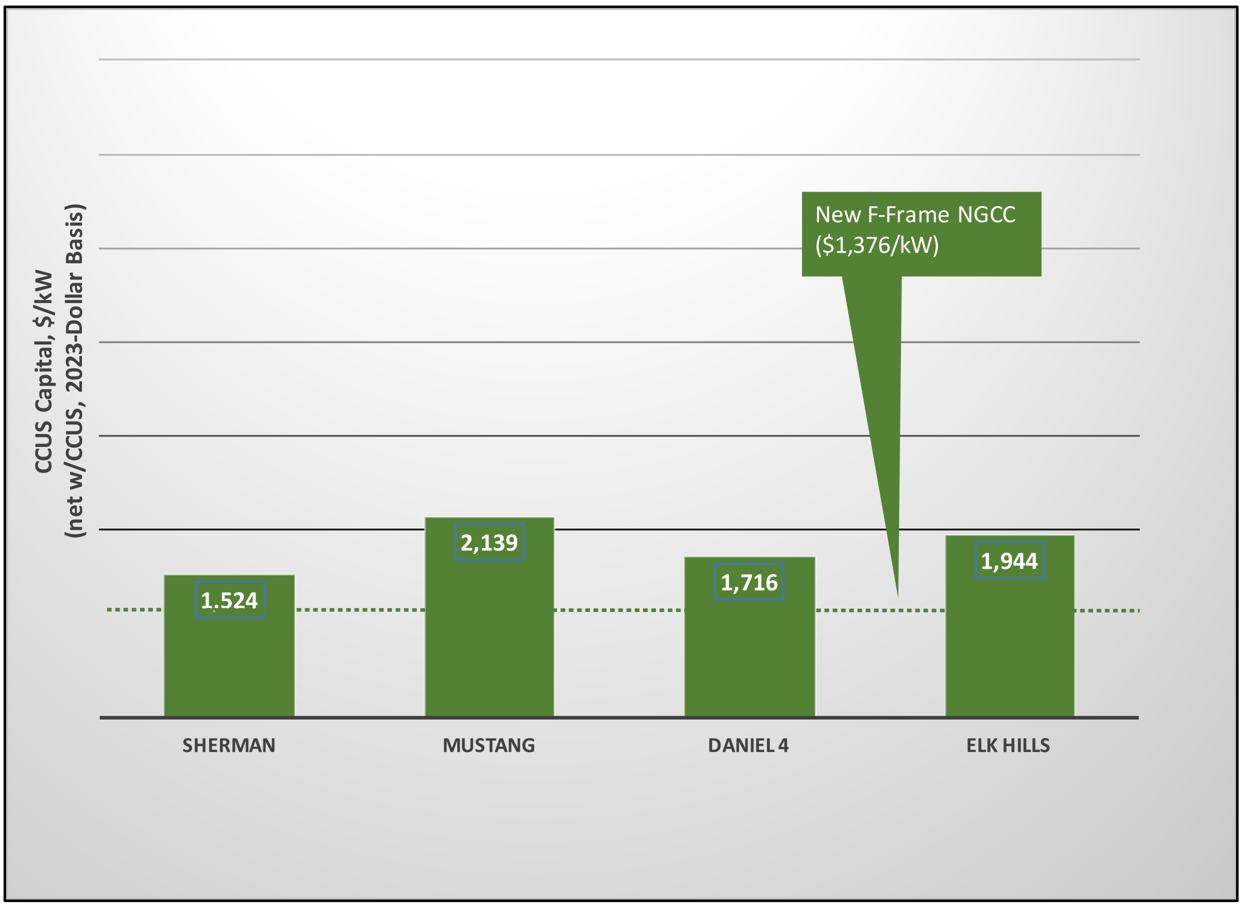


Figure 5-2. CCUS Capital Cost as Reported for NGCC FEED Studies

[34] Panda Sherman 2022 Final Report.
[35] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study, DE-FE0031844, 2022 Carbon Management Research Project Review, August 17, 2022.
[36] Lunsford, L., et. al., Front End Engineering Design of Linde-BASF Advanced Post-Combustion $CO_2$ Capture Technology at a Southern Company Natural Gas-Fired Power Plant, Final Scientific/Technical Report, per DE FE0031847, September 30, 2022. Hereafter 2022 Daniel FEED Report.
[37] Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Agreement DE-FE0031842, for US DOE/NETL, January 2022. Hereafter 2022 Elk Hills FEED Report.

Figure 5-2 also presents the capital cost for a hypothetical state-of-the-art NGCC generating unit without CCUS, as evaluated by NETL.[38] The NETL study estimates capital cost for F-Class and H-Frame combustion turbine designations, with cost for a “2 x 1” F-Frame design capable of 727 MW (net) and 6,363 Btu/kWh heat rate shown in Figure 5-2 as $1,376/kW.

Capital costs in Figure 5-2 vary widely by site, driven by, among other factors, the steam source for CCUS. For example, CCUS capital projected for Panda Sherman ($1,524/$/kW $_{\text{(net, with CCUS)}}$ is the lowest, with a key contributing factor being the use of the existing HRSG to provide steam for CCUS duty – but at the cost of a generating capacity penalty. Conversely, the highest capital cost (~$2,000/$/kW $_{\text{(net, with CCUS)}}$) is estimated for two units (Mustang, Daniel 4), with contributing factors being the need for auxiliary boilers to provide steam and preserving generating capacity.

The average of the four FEED studies – albeit representing different design concepts to provide CCUS steam –is $1,831/$/kW $_{\text{(net, with CCUS)}}$. This value represents a 30% premium to the cost developed by NETL for a 727 MW unit without CCUS.

<u>Conclusion</u>. The cost for CCUS applied to either coal-fired or NGCC generating assets approximates or exceeds that for stand-alone generation, without CCUS. For coal-fired assets, the cost for a new 650 MW subcritical unit and the average of the CCUS cost results (the latter as $/kW$_{\text{(net, with CCUS)}}$ from six FEED studies is almost identical, at $3,373/kW$_{\text{(net, with CCUS)}}$. For NGCC the cost of the CCUS process - based on an average of four FEED studies – at $1,831/kW$_{\text{(net, with CCUS)}}$ exceeds by 30% the cost of new 727 MW greenfield generation.

[38] Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3, DOE/NETL-2023/3848, May 31, 2023. Hereafter 2023 NGCC CCUS Retrofit.

# 6 $CO_2$ Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in $CO_2$ pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. The August 2023 Technical comments presented details of the ongoing permitting conflicts and the delays incurred for certain projects. Section 6 provides a brief update on three notable projects.

The major actors in the pipeline permitting debates are summarized as follows:

- Navigator Ventures[39] proposed 900-mile Heartland Greenway $CO_2$ pipeline, bisecting Iowa from northwest to southeast and transporting $CO_2$ to Illinois. The approximate $3.2B project extends a total of 1,300 miles through South Dakota, Nebraska, Minnesota, and Iowa.

- Wolf Carbon[40] proposed 280 miles of pipeline to transport $CO_2$ from ADM ethanol-producing facilities in eastern Iowa to Decatur, IL, for terrestrial sequestration.

- Summit Carbon[41] plans 700 miles of pipeline in western and northern Iowa to transport $CO_2$ to North Dakota for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[42]

Each of these organizations has pursued pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state– Iowa presents perhaps the most structured steps, and Nebraska the least. Landowners cite numerous reasons for resisting access to their property. These include the role of eminent domain, safety due to $CO_2$ leaks, and concern that agricultural productivity is compromised within pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[43]

The status of the pipeline permits as of July 2025 is described subsequently.

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[39] https://heartlandgreenway.com/about-us/.
[40] https://wolfcarbonsolutions.com/mt-simon-hub/.
[41] https://summitcarbonsolutions.com/project-footprint/.
[42] Proposed Iowa Pipeline Would Cross 30 Counties, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/.
[43] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way.

## 6.1 Navigator Ventures

Navigator Ventures, in October 2023, canceled the 1,300-mile pipeline project planned to cross five Midwestern states.[44] The company cited the challenging regulatory environment, particularly in South Dakota and Iowa. The permit was denied by South Dakota in September 2023[45] and Navigator requested Iowa to pause the permit application.[46] The permit was also withdrawn for consideration from Illinois.

Landowners and community groups organized against the Navigator project, focusing on concerns regarding eminent domain and the potential disruption to their ability to utilize their land. Significant opposition also was derived from concern about the potential for $CO_2$ leaks and other environmental impacts. Navigator has not clarified if and when these permits will be reconsidered.

## 6.2 Wolf Carbon

Wolf Carbon Solutions abandoned plans to construct the 95-mile segment of their pipeline across eastern Iowa, per a December 2024 filing with the Iowa Utilities Commission.[47] Wolf Carbon Solutions indicates the decision may not be permanent, with activities potentially restarted pending resolution of uncertainties.

The rational for abandoning the permits is the same as for Navigator - impact of eminent domain on private property rights and owners concern for public health. The concern for public safety was also highlighted as an issue by the Illinois Commerce Commission.

## 6.3 Summit Carbon

Summit as of July 2025 remains the only presently active developer of a $CO_2$ pipeline. Figure 6-1 presents the proposed routing for the Summit Carbon pipeline within the five affected states.[48]

The Summit Carbon project experienced continued delays and regulatory hurdles, particularly in South Dakota. Iowa and North Dakota issued permits in August and November of 2024, respectively, and Minnesota issued approval in December 2024.[49] The company is still seeking permit approval in South Dakota and faces legal challenges in several states

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[44] https://www.reuters.com/sustainability/climate-energy/navigator-co2-ventures-cancels-carbon-capture-pipeline-project-us-midwest-2023-10-20/
[45] https://www.reuters.com/article/business/energy/south-dakota-regulator-rejects-navigator-co2-ventures-carbon-pipeline-applicatio-idUSKBN30D18N/
[46] https://www.reuters.com/sustainability/navigator-co2-ventures-asks-iowa-pause-ccs-pipeline-permit-process-2023-10-02/
[47] https://carbonherald.com/wolf-carbon-solutions-abandons-carbon-pipeline-plans-in-iowa/
[48] https://www.desmoinesregister.com/story/money/business/2024/06/27/summit-carbon-pipeline-map-iowa-utilities-board-what-is-a-carbon-pipeline/74216858007/
[49] https://carbonherald.com/summit-gets-the-green-light-for-carbon-capture-pipeline-in-minnesota/

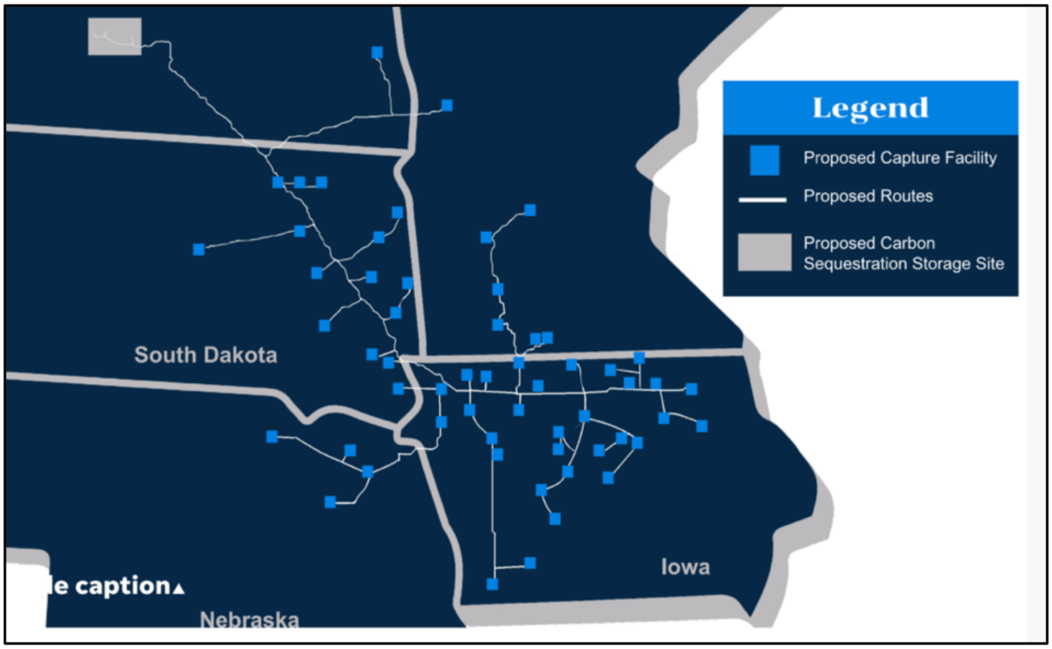


Figure 6-1. Proposed Summit $CO_2$ Pipeline Routing: Five States

In South Dakota, after an initial application was rejected, Summit reapplied after altering pipeline routing to minimize barriers. Despite this change, the South Dakota Public Utility Commission voted 2-1 to reject the revised route proposed.[50] A key factor is a new state law addressing eminent domain. Summit plans to alter the pipeline routing again, abandoning the most challenging elements of the route and negotiating directly with individual landowners on the most essential aspects of the pipeline.

Summit also faced legal challenges regarding the pipeline's classification as a "common carrier" which enhances the ability to invoke eminent domain to acquire land.

Conclusion. Resistance to $CO_2$ pipelines proposed by Navigator and Wolf Carbon has forced, at least for now, reconsideration of these projects, despite the projected benefits to the local economy of supporting the ethanol-based production facilities in these states. It is possible that any change in the 45Q tax provisions will further erode the feasibility of these projects.

Only Summit Carbon Solutions remains an entity that, at present, with permits from 4 states in hand, continues to pursue $CO_2$ pipelines.

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[50] https://carbonherald.com/south-dakota-regulators-block-summits-8-9b-carbon-capture-pipeline/#:~:text=Summit%2C%20which%20has%20already%20invested%20more%20than,would%20refile%20with%20a%20revised%2C%20smaller%20route.