Appendix: Carbon Capture and Sequestration

Fossil fuel-fired power plants can be and are being built and retrofitted with carbon capture and storage and, when their emissions are controlled in that way, can play a valuable role in a decarbonized grid by providing clean firm power when required and acting as flexible, low-carbon backup to renewable generation. The technology is adequately demonstrated and cost reasonable for new and existing coal- and gas-fired power plants. The U.S. has been active in developing a favorable economic landscape for CCS deployment, including through the funding of demonstration projects and transport and storage infrastructure for CO_2 as well as by establishing an economic incentive through the 45Q tax credit. This appendix surveys the existing state of CCS technology and its qualities as they relate to its role in mitigating power sector emissions.

I. Post Combustion Capture Is Adequately Demonstrated

A long history of experience, in the United States and around the world, demonstrates the efficacious application of post combustion carbon capture technology on power plants. In addition to the several examples of existing deployment of capture technology at power plants, a wealth of knowledge—from permit and application reviews, FEED studies, vendor-provided information, and deployment of the technology in other industries—developed over many years reinforces the technology's readiness.

A. Existing Deployment of Carbon Capture at Power Plants

For many years and at many sites, carbon capture technology has been applied on power plants and similar flue gas streams. Demand for CO_2 from sectors such as the food and beverage industry drove the development of many smaller-scale, post-combustion capture plants from the early 1980s, including coal-, gas-, and oil-fired boilers and furnaces, gas engines and gas turbines.[1] These applications separate CO_2 from gas mixtures of very similar composition to full-scale power plants, usually using amine solvent-based technologies supplied by companies including Fluor, MHI and ABB Lummus.[2] They range in scale from around 100,000 to 500,000 tons of CO_2 per year.[3]

For example, since 1978, up to 270,000 tons per year of CO_2 have been captured from a captive coal power plant operated by Searles Valley Minerals in California for use in the production of soda ash. Two AES-owned coal power plants capture industrial quantities of CO_2 from flue gas

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[1] *Commercially Available CO_2 Capture Technology*, Power (Aug. 1, 2009), https://perma.cc/D83M-JUGY.

[2] *See* Int'l Energy Agency (IEA) GHG R&D Programme (IEAGHG), *Improvement in power generation with post-combustion capture of CO_2* (2004), https://perma.cc/TH22-65C4. *See* Table 1 *infra*.

[3] CATF, *Carbon capture and storage: What can we learn from the project track record?* (July 31, 2024), https://perma.cc/6B5V-L2JE.

slipstreams for use in the food and beverage industry and dry ice, using ABB Lummus capture technology: 66,000 metric tons per year are captured at Shady Point, OK, while 110,000 metric tons per year are captured from the 180 MW Warrior Run, MD. [4]

Using these existing technologies, modified variants, or entirely new solvents, more large-scale trials on coal power plant flue gas were carried out from the 1990s, with climate mitigation as the primary motivation.

In 2014, this culminated in the first full-scale demonstration of CO_2 capture, processing all of a coal power plant's flue gas output, with the 1 million metric ton per year scale plant at Boundary Dam 3 in Canada using Shell Cansolv technology. Although this plant encountered initial operational issues associated with excessive entry of flue gas contaminants into the solvent system, correctional measures and modifications have led to the facility consistently meeting its availability target and seeing steady increases in capture volumes from 2022, 2023, and 2024, from about 750,000 to 787,000 to 848,000 tons per year, respectively.[5]

In 2011, MHI used their experience with capture on natural gas-fired boilers to demonstrate capture on coal at Southern Company's Plant Barry in Alabama on a 25 MW slipstream. [6] Success at Plant Barry enabled MHI to apply carbon capture at a much larger scale at the Petra Nova project on the WA Parish plant (a 240 MW-equivalent slipstream).[7] Petra Nova operated successfully from January 2017 to September 2020, when it suspended operation due to falling oil prices that impacted a business model reliant on enhanced oil recovery. Over these three years, the project captured 83 percent of the planned volume of CO_2, but with a steady increase from 72 percent in 2017 to 95 percent in 2019, as technical issues (many similar to those encountered at Boundary Dam) were addressed.[8] Outages of the CO_2 capture unit were responsible for only 28 percent of unplanned outages.[9] The Petra Nova CCS plant was restarted

[4] 89 Fed. Reg. 39798, 39846-47, 49 (May 9, 2024) (hereinafter "Carbon Pollution Standards").

[5] *See* Brent Jacobs et al., *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities* (2022), https://dx.doi.org/10.2139/ssrn.4286430; *BD3 Status Update: Q4 2024*, SaskPower (Jan. 21, 2025), Saskpower, *BD3 Status Update: Q4 2024*, (Jan. 21, 2025) (noting total capture volumes in 2022, 2023, and 2024 YTD), https://perma.cc/7YWQ-CHBG.

[6] Mass. Inst. Tech., Carbon Capture and Sequestration Technologies Program, *Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project*, https://perma.cc/P55X-QPRV (last visited Aug. 5, 2025).

[7] DOE, Off. Fossil Energy & Carbon Mgmt. (OFECM), *Petra Nova - W.A. Parish Project*, https://perma.cc/63HS-RXS3 (last visited Aug. 5, 2025).

[8] DOE/NETL, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report* at 47 (Mar. 31, 2020), https://www.osti.gov/servlets/purl/1608572 [Attachment G]

[9] *Id* at 41.

in September 2023.[10] Between this reopening and February 2025, the project captured approximately 1.5 million metric tons of CO_2.[11]

Likewise, Fluor developed a carbon capture project at the Bellingham NGCC plant in Massachusetts from 1991 to 2005 capturing 85 to 95 percent of CO_2 from a 40 MW slipstream.[12] They used this experience to design a coal-fired power plant capture pilot in Wilhelmshaven, Germany, that operated in 2012.[13]

In China, capture of 500,000 tons per year from China Energy's Guodian Taizhou power plant began in June 2023 and achieves capture rates of over 90 percent.[14] Five other power-sector capture projects are also operational in China: China Energy's Jinjie facility (150,000 metric tons per year), China Huaneng's Shanghai Shidonkou facility (120,000 tons) and Shidongkou Power Plant (120,000 tons), the Haifeng Carbon Capture Test Platform (30,000 tons), and the China Power Investment Chongqing Shuanghuai Power Plant (10,000 tons).[15]

While early large-scale demonstrations of CO_2 capture from coal power have encountered periods of low availability – particularly immediately following commissioning – operation and design modifications have been incorporated and required to improve the availability of these units in currently planned projects, indicating lessons learned.[16] As a result, the capture processes themselves have consistently removed CO_2 from the flue gas they treat at their design rate or above. On average, the capture unit at Petra Nova removed 90.2 percent of CO_2 in the flue gas it processed, while the Boundary Dam 3 capture unit has consistently captured around 90 percent.[17] Equally, these coal power plant experiences are now informing capture projects at natural gas-

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[10] Reuters, *Carbon capture project back at Texas coal plant after 3-year shutdown* (Sept. 14, 2023), https://www.reuters.com/business/energy/carbon-capture-project-back-texas-coal-plant-after-3-year-shutdown-2023-09-14/.

[11] *See* DOE/NETL, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report* (Mar. 31, 2020), Attachment G (approximately 3.5 million metric tons captured pre-mothballing); *id* at 51; ENEOS Xplora, *Petra Nova Captures More Than Five Million Tons of Carbon Dioxide* (Feb. 17, 2025), https://www.eneos-xplora.com/english/newsrelease/upload_files/Xplora20250217EN.pdf.

[12] DOE, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://perma.cc/Z97V-YSCC https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon Capture Opportunities for Natural Gas Fired Power Systems.pdf (last visited Aug. 6, 2023).

[13] Univ. Edinburgh, *Wilhelmshaven Pilot Plant: Project Details*, https://perma.cc/A2F7-ARPL (last visited Aug. 5, 2025).

[14] Nathan Bongers, Low Emission Technology Australia, *China's impressive strides towards carbon capture, utilization, and storage (CCUS)* at 36, 42–43 (May 2025), *available at* https://letaustralia.com.au/reports/chinas-impressive-strides-towards-carbon-capture-utilisation-and-storage-ccus/ [Attachment D].

[15] *Id.* at 72-75.

[16] Similarly, early flue gas SO_2 scrubbers had poor initial performance but EPA nonetheless concluded they were adequately demonstrated as a basis for the 1971 NSPS, a conclusion that was upheld by the courts. *See Essex Chem. Corp.*, 486 F.2d at 440.

[17] CATF, *Carbon capture and storage: What can we learn from the project track record?* at 27-30, (July 31, 2024), https://perma.cc/6B5V-L2JE.

fired combined cycle plants, which generally use the same family of solvents to capture carbon dioxide with minor changes to account for differences in flue gas composition.[18]

Table 1 illustrates the wealth of commercial reference plants that have applied CO_2 capture to post-combustion flue gas streams from power plants, smaller combustion sources, and industrial facilities with similar flue gas compositions in industry, such as steam reformer flue gas.

Table 1. Significant solvent-based post-combustion CO_2 capture projects on power plants, industrial furnaces and other combustion sources[19]

Vendor	Location	Exhaust Stream	CO_2 Use
ABB	Searles Valley, CA	Coal Boiler	Chemicals Industry
ABB	Warrior Run, MD	Coal Boiler	Food Industry
ABB	Shady Point, OK	Coal Boiler	Food Industry
TPRI	Shanghai, PRC	Coal Boiler	Food Industry
TPRI	Beijing, PRC	Coal Boiler	Demonstration, Food
MHI	Kedah Darul Aman, Malaysia	NG fired steam reformer (SR) flue gas	Urea production
MHI	Aonla, India	NG fired SR flue gas	Urea Production
MHI	Phulpur, India	NG fired SR flue gas	Urea Production
MHI	Kakinada, India	NG fired SR flue gas	Urea Production
MHI	Vijaipur, India	NG fired SR flue gas	Urea Production
MHI	Bahrain	NG fired SR flue gas	Urea Production
MHI	Phu My, Vietnam	NG fired SR flue gas	Urea Production
MHI	Hyogo, Japan	Gas turbine exhaust	Demo (research)
MHI	Fukuoka, Japan	NG fired SR flue gas	General use
MHI	Abu Dhabi, UAE	NG fired SR flue gas	Urea Production

[18] Wood Group, *CCS Technology Transfer Assessment Report* (2023) [hereinafter *Wood Report*] [Attachment H].

[19] Table updated from work submitted to the Carbon Pollution Standards docket, and developed by CATF in preparing Comments of CATF & NRDC in Response to Proposed Rule: Emissions Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emissions Guidelines Implementing Regulations; Revision to New Source Review Program, Docket ID No. EPA-HQ-OAR-2017-0355-24266 at Appendix B. tbl. 1 (Oct. 31, 2018), https://www.regulations.gov/comment/EPA-HQ-OAR-2017-0355-24266 (several sources' links have since broken). MHI describes these as "post-combustion" capture projects, and the exhaust gas from which the CO_2 is separated is similar to conventional combustion gases (68 percent nitrogen, 8 percent CO_2, balance mostly water). Licensing of the PCC technology developed by Kerr-McGee was transferred to ABB in 1990. Howard Herzog, *The Economics of CO_2 Separation and Capture*, at tbl.1, n.1 (N.D.), https://perma.cc/K22B-CVH7. Unless otherwise indicated, information on the MHI projects listed here are from MHI, *Update of MHI CO_2 Capture Technology* (2021), https://perma.cc/7N84-UBFW; Akihito Otani, *Achievement of ENI Ravenna CCS and next CO_2 capture plant expectation*, presented at ZEP projects network, Bologa, Italy (June 24–25, 2025) [Attachment I]; Fluor, *Econamine FG Plus* (2025), https://perma.cc/J8HH-GCEX.

MHI	District Ghotoki, Pakistan	NG fired SR flue gas	Urea Production
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas	Urea production
MHI	Plant Barry, AL	Coal Boiler	Demo (storage)
MHI	India	NG fired SR flue gas	Urea production
MHI	Qatar	NG fired SR flue gas	Urea production
MHI	Japan	NG fired furnace	General use (dry ice etc.)
MHI	Russia	NG fired SR flue gas	Urea and metamine production
Fluor	Bellingham, MA	Gas Turbine Exhaust	Food Industry
Fluor	Lubbock, TX	Natural Gas	Enhanced Oil Recovery
Fluor	Carlsbad, NM	Natural Gas	Enhanced Oil Recovery
Fluor	Santa Domingo, DR	Light Fuel Oil	Enhanced Oil Recovery
Fluor	Barranquilla, Columbia	Natural Gas	Food Industry
Fluor	Quito, Ecuador	Light Fuel Oil	Food Industry
Fluor	Brazil	NG / Heavy Fuel Oil	Food Industry
Fluor	Rio de Janeiro, Brazil	Steam Reformer	Methanol Production
Fluor	Sao Paulo, Brazil	Gas Engine Exhaust	Food Production
Fluor	Argentina	Steam Reformer	Urea Plant Feed
Fluor	Spain	Gas Engine Exhaust	Food Industry
Fluor	Barcelona, Spain	Gas Engine Exhaust	Food Industry
Fluor	Bithor County, Romania	Heavy Fuel Oil	Food Industry
Fluor	Cairo, Egypt	Light Fuel Oil	Food Industry
Fluor	Israel	Heavy Oil Boiler	Food Industry
Fluor	Uttar Pradesh, India	NG Reformer Furnace	Urea Plant Feed
Fluor	Sechuan Province, PRC	NG Reformer Furnace	Urea Plant Feed
Fluor	Singapore	Steam Reformer	Food Industry
Fluor	San Fernando, Philippines	Light Fuel Oil	Food Industry
Fluor	Manila, Philippines	Light Fuel Oil	Food Industry
Fluor	Osaka, Japan	LPG	Demo Plant

Fluor	Chibu, Japan	Refinery Gas Mixture, Heavy Fuel Industry	Food Industry
Fluor	Yokosuka, Japan	Coal/Heavy Fuel Oil	Demo Plant
Fluor	Botany Australia	Natural Gas	Food Industry
Fluor	Alton, Australia	Natural Gas	Food Industry
Alstom	New Haven, WV	Coal Boiler	Demo (ammonia)
Alstom	Mongstad, Norway	NG turbine/refinery	Demo (ammonia)
Aker	Mongstad, Norway	NG turbine/refinery	Demo (amine)

Even before the Carbon Pollution Standards, EPA had already found that CCS was adequately demonstrated, relying on CCS as the basis of its 2015 performance standards for new coal-fired plants, which the proposed repeal does not disturb. As outlined above, CCS has been successfully deployed on coal-fired power plants, and while it is yet to be deployed on a large-scale gas turbine, this has been due to the lack of a regulatory driver or suitable incentives, rather than any limitations of current technologies.[20] There is nothing fundamentally different about applying the capture technology already used to the emissions of large gas-fired plants.[21] Both EPA (in setting the 2015 NSPS) and suppliers (e.g. MHI, in designing the capture equipment used at Plant Barry) have relied on past experience with capturing emissions from gas-fired boilers and turbines. There are now a wide range of commercial capture solvent technologies available that have undergone years of testing on diverse CO_2 sources.

B. Carbon Capture at Power Plants Planned and Under Construction

There are many new projects applying carbon capture technology currently planned for commercial use in the power sector in the U.S. and internationally, including many which integrate carbon sequestration as well. CATF's project tracker identifies 12 proposed projects on coal power plants and 20 on natural gas projects in the USA.[22] As shown in Table 2 and Table 3, there are 9 gas power plants and 3 coal power plants that have progressed to the FEED study stage, with at least 8 studies completed to date. These FEED studies confirm the readiness and availability of capture technology for all types of fossil fuel-fired power plants, in addition to a diverse range of commercially ready technology vendors.

[20] Comments of CATF, Re: Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0289 at 10 (June 6, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0289-0029.

[21] *Id.*

[22] Clean Air Task Force, *US Carbon Capture Activity and Project Table* (last visited Aug. 5, 2025) https://www.catf.us/ccstableus/ (filter by subsection "Coal" and "Gas") [Attachment J].

Table 2. Specifications and status of CCS projects underway in the United States[23]

Project	Generating capacity	CO_2 captured	Capture technology	Target capture rate	Notes
NGCC plants					
Panda Energy, TX[24]	420 MW	645,000 to 1 million tons per year depending on capacity factor	MEA (generic)	85%	Existing NGCC, FEED complete
Plant Daniel[25]	375 MW		Linde-BASF	90%	Existing NGCC, FEED complete
Quail Run Energy Center, TX[26]	550 MW	1.75 million metric ton/year	Unannounced	95%	Existing NGCC, permit issued
Deer Park Energy Center, TX[27]	1,116 MW	5 million metric ton/year	Shell Cansolv	95%	Existing NGCC, FEED, permit issued
Baytown Energy Center, TX[28]	810 MW	2.0 million metric tons/year	Shell Cansolv	95%	FEED awarded, permit issued
Delta Energy Center, CA[29]	857 MW	2.3 million metric tons/year	ION	95%	Existing NGCC, FEED in development

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[23] CATF, *The time is now: The Biden administration must adopt strict CO2 emission standards for the power sector* (Feb. 7, 2023), https://www.catf.us/2023/02/time-now-biden-administration-must-adopt-strict-co2-emission-standards-power-sector/.

[24] DOE, OFECM, *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants* (Sept. 23, 2019) [hereinafter, DOE, *FOA 2058*], https://perma.cc/FRA4-QGD3; *see also* W.R. Elliot, Bechtel Nat'l, Inc., *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant* (2022), https://perma.cc/XY5P-79GZ.

[25] Landon Lunsford et al., *Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant (Final Scientific/Technical Report)* (Sept. 2022), https://www.osti.gov/biblio/1890156.

[26] Texas Comptroller of Pub. Accounts, Data Analysis and Transparency Form 50-296-A for Quail Run Carbon Capture Project, https://perma.cc/NK29-CB52 (last visited Aug. 6, 2025).

[27] DOE, OFECM, *Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants* (Oct. 6, 2021), https://perma.cc/SS3W-HN8K [hereinafter DOE, *FOA 2515*]; *see also* Calpine, *Carbon Sequestration Studies*, https://perma.cc/6K8U-9L77 (last visited Aug. 6, 2025).

[28] OCED, *Carbon Capture Demonstration Projects Program – Baytown Carbon Capture and Storage Project*, U.S. Department of Energy, https://perma.cc/YTZ3-J8QA.

[29] DOE, *FOA 2515*; *see also* Andrew Awtry, ION Clean Energy, *Project Delta: Front-End Engineering and Design for a CO_2 Capture System at Calpine's Delta Energy Center* (Aug. 5, 2024), https://perma.cc/3257-M8QC.

Plant Barry, AL[30]	525 MW	1.5 million metric tons/year	Linde-BASF	95%	Existing NGCC, FEED
Polk Power Station, FL[31]	~280 MW	~800,000 metric tons/year	ION	95%	Existing NGCC, FEED
LG&E Cane Run[32]	700 MW	1.7 million metric tons/year	UofK technology	95%	Existing NGCC, FEED
Mustang Station, TX[33]	460 MW	1.6 million metric tons/year	PZAS (piperazine)	90%	Existing NGCC, FEED complete
Chevron Kern River Eastridge, CA[34]	50 MW, steam	300,000 metric tons/year	Flour	N/A	Existing Cogen, Pre-FEED
CalCapture (Elk Hills), CA[35]	550 MW	Up to 1.4 million metric tons/year	NEXT	95%	Existing NGCC, FEED complete
Coyote Clean Power, CO[36]	280 MW	N/A	Allam-Fetvedt Cycle	100%	New Natural Gas, Allam Cycle, Pre-FEED
Broadwing Clean Energy, IL[37]	280 MW	850,000 metric tons/year	Allam-Fetvedt Cycle	90%	New Natural Gas, Allam Cycle, Pre-FEED

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[30] Sonal Patel, *DOE Backs Carbon Capture Development at Two Major Gas-Fired Power Plants*, Power (Sept. 1, 2022), https://perma.cc/8MMR-B8TX.

[31] DOE, OFECM, *Additional Selections for Funding Opportunity Announcement 2515*, https://perma.cc/R9YN-EYTN (last visited Aug. 6, 2025) [hereinafter DOE, *Additional Selections*]. DOE's Categorical Exclusion Designation Form for the FEED Study suggests that only Unit 2 is the subject of the FEED study. Therefore, the amount of CO_2 subject to the FEED is revised downward from the DOE announcement. DOE, NETL, *Categorical Exclusion (CX) Designation Form for Project No. DE-FOA-0002515* (2022), https://perma.cc/E69X-24W9.

[32] *Id.*

[33] DOE, *FOA 2058*; *see also* Gary Rochelle et al., *Cost Details from Front-End Engineering Design of Piperazine with the Advanced Stripper* (2022), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4281548.

[34] Chevron, *Chevron Launches Carbon Capture and Storage Project in San Joaquin Valley* (May 18, 2022), https://perma.cc/X8AK-SUN7 (last visited July 31, 2025); Fluor, *Fluor's Econamine FG Plus[SM] Carbon Capture Technology Selected to Reduce CO_2 Emissions at Chevron Facility* (Feb. 6, 2024), https://newsroom.fluor.com/news-releases/news-details/2024/Fluors-Econamine-FG-PlusSM-Carbon-Capture-Technology-Selected-to-Reduce-CO2-Emissions-at-Chevron-Facility/default.aspx.

[35] Abhoyjit S. Bhown, EPRI, *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant* (July 11, 2022), https://perma.cc/7EA3-XPZ6.

[36] Sonal Patel, *8 Rivers Unveils 560 MW of Allam Cycle Gas-Fired Projects for Colorado, Illinois*, Power (Apr. 15, 2021) https://perma.cc/LLP7-9J5J.

[37] 8 Rivers Capital LLC, *8 Rivers Capital ADM Announce Intention To Make Illinois Home To Game-Changing Zero Emissions Project*, PRNewswire (Apr. 15, 2021), https://perma.cc/WP9E-ZRJM.

Competitive Power Ventures, WV[38]	2060 MW	Up to 5.5 million metric tons/ year	Unannounced	95%	New NGCC-CCS, early development
Diamond Vault, Madison Unit 3, LA[39]	600 MW	3.6 to 5.0 million metric tons/year	MHI	95%	NGCC, FEED underway
Lake Charles Power Plant, LA[40]	994 MW	3.0 million metric tons/year	MHI	95%	Existing NGCC, pre-FEED
Coal plants (retrofits)					
Milton R. Young (Project Tundra), ND[41]	455 MW	3.3 million metric tons/year	MHI	90%	Permit issued
Dry Fork, WY[42]	400 MW	2.2 million metric tons/year	MTR (membranes)	70%/90%	FEED complete. 90% capture FEED underway.
Dave Johnson, WY[43]	330 MW	1.26 million metric tons/year	Allam-Fetvedt Cycle	N/A	Pre- FEED
Gerald Gentleman, NE[44]	700 MW	4.3 million metric tons/year	ION	90%	FEED complete
Prairie State, IL[45]	816 MW	6.2 to 8.2 million metric tons/year	MHI	95%	FEED complete

[38] Competitive Power Ventures, *CPV Shay Energy Center* (June 2025), https://perma.cc/T5BT-CBG6.

[39] Mark Bordelon & Cleco Power, *Diamond Vault Carbon Capture FEED Study* (Aug 28–Sept. 1, 2023), https://perma.cc/52GK-7AJ3.

[40] Crescent Midstream, *Crescent Midstream Selected to Develop an Integrated Carbon Capture Solution for Entergy Natural Gas Power Plant* (Sept. 20, 2024), https://perma.cc/8PZE-EYRT.

[41] Gerry Pfau et al., *Front-End Engineering and Design: Project Tundra Carbon Capture System (Final Report)* (Feb. 19, 2023), https://www.osti.gov/biblio/1987837 (final FEED); *infra* n.74 (permit).

[42] Tim Merkel et al., Membrane Tech & Rsch., Inc., *Commercial-Scale Front-End Engineering Design (Feed) Study For Mtr's Membrane CO_2 Capture Process* (2022), https://perma.cc/UZZ3-QWSJ.

[43] Rocky Mountain Power, *Rocky Mountain Power and 8 Rivers to collaborate on proposed Wyoming carbon capture project* (Apr. 1, 2024), https://perma.cc/7694-PPH4.

[44] DOE, *FOA 2058*.

[45] *Id.*

Four Corners, NM[46]	1540 MW	10 million metric tons/year	MHI	95%+	Awarded DOE FEED

Internationally, the United Kingdom is particularly active in the development of large-scale CCS for NGCC, summarized in Table 3. In 2015, Shell completed a FEED study for retrofit of 90 percent post-combustion capture to a 400 MW unit at the 1180 MW Peterhead gas plant.[47] For comparison, the average size of a new NGCC plant installed in the U.S. in 2017 was an average of 820 MW.[48] Although the plan was abandoned due to withdrawal of government funding,[49] this study did not identify any significant technical barriers or risks.

Following a renewed commitment to deploy CCS in the power sector (and more widely) in the UK, several new gas power plant-based proposals are currently undertaking FEED studies and competing to be prioritized in the development of government-supported CO_2 clusters.[50] These comprise greenfield and retrofit combined cycle plants with post-combustion capture targeting at least 95 percent capture rates, as specified by the UK's published BAT guidelines for power-CCS.[51] These include Peterhead (910 MW, Scottish Cluster),[52] Keadby 3 (910 MW, Humber Cluster), [53] Stallingborough, BP's Net Zero Teesside Power (742 MW),[54] and Connah's Quay

[46] William Ampomah, *Bipartisan Infrastructure Law (BIL): Four Corners Carbon Storage Hub: CarbonSAFE Phase III Project*, DE-FE0032452 (Aug. 5-9, 2024), https://perma.cc/7TC5-T62Y.

[47] Shell U.K. Ltd., *FEED Summary Report for Full CCS Chain*, Doc. No. PCCS-00-MM-AA-7180-00001 (Mar. 22, 2016), https://perma.cc/6W6F-RE6T.

[48] *See* EIA Today in Energy, *Power blocks in natural gas-fired combined-cycle plants are getting bigger*, (Feb. 12, 2019), https://perma.cc/W4FB-RRTW.

[49] BBC, *UK Government Spent 100m On Cancelled Carbon Capture Project* (Jan. 20, 2017), https://www.bbc.com/news/uk-scotland-scotland-business-38687835.

[50] U.K. Dep't for Bus., Energy & Indus. Strategy, *Cluster sequencing Phase-2: eligible projects (power CCUS, hydrogen and ICC)* (Mar. 22, 2022), https://perma.cc/85MB-JGM2.

[51] U.K. Env't Agency, *Post-combustion carbon dioxide capture* (Jul. 2, 2021),https://perma.cc/F7ZC-SDRW; Jon Gibbins & Mathieu Lucquiaud, *BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fueled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK* (Dec. 2022), https://perma.cc/SM9P-86PD.

[52] Hamish Penman, *Plans for trailblazing Peterhead CCS power station lodged with government*, Energy Voice (Mar. 31, 2022), https://www.energyvoice.com/renewables-energy-transition/ccs/uk-ccs/399875/plans-for-trailblazing-peterhead-ccs-power-station-lodged-with-government/.

[53] SSE Thermal, *Keadby 3 Carbon Capture Power Station, Capturing the potential of the Humber*, https://perma.cc/SMF2-FQY6 (last visited Aug. 6, 2025).

[54] Press Release, BP, *BP and Partners Award First Engineering Contracts Advancing Major UK Power and Carbon Capture Projects* (Dec. 15, 2021), https://perma.cc/RRK4-5WDU.

(1100 MW).[55] These projects are eligible for support from UK's Dispatchable Power Agreement,[56] illustrating that—when an appropriate investable business model or regulations are put in place by policy—power companies and technology developers are in a position to deploy CCS-equipped gas plants in the near term. Following award of initial government funding support in October 2024, Net Zero Teesside Power made a final investment decision in December 2024[57] and is expected to start construction in mid-2025, using Shell Cansolv capture technology. This new NGCC plant will produce 742 MW of net power and is designed to achieve a capture rate of 96 percent.[58] To receive subsidy payments, the power plant must demonstrate it has achieved within 5 percent of this rate,[59] and is expected under the terms of its permit to maintain a capture rate of 95 percent under normal operation.[60] The financial commitment to this plant by its developers is evidence of the commercial guarantees underlying capture performance at this level, taking into account that the plant will also be expected to operate flexibly.

Plans to retrofit CCS to existing NGCC units in the UK include a 1240 MW CHP unit at Immingham, and RWE's plants at Staythorpe and Pembroke.[61]

In addition to the operational projects noted above, China is planning several large-scale capture projects on power. China Energy is undertaking a feasibility study for deploying full-scale capture on a 600 MW coal unit at Jinjie, where it already operates a 150,000 ton per year demonstration unit since 2021. Power company China Huaneng is currently constructing what will become the largest coal power capture plant in the world at the Longdong Energy Base in Gansu province, which will capture 1.5 Mtpa when operational (planned for 2025).[62] In total,

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[55] Power Technology, *Power Plant Profile: Connah's Quay CCGT Low Carbon Power Plant, UK*, https://perma.cc/L2CF-8HHA (last updated Nov. 11, 2024).

[56] U.K. Dep't for Bus., Energy, and Indus. Strategy, *Carbon Capture, Usage and Storage: Dispatchable Power Agreement business model summary and consultation* (Jun. 10, 2022), https://perma.cc/MM4V-7E5E.

[57] Net Zero Teesside Power Ltd. And Low Carbon Contracts Company LTD Agreement Relating to Net Zero Teesside Power (Nov. 19, 2024), https://perma.cc/9EXR-LMX5.

[58] Net Zero Teesside & NZT Power, *Net Zero Teesside Power*, https://perma.cc/UN7M-S97U (last visited Aug. 6, 2025).

[59] UK Department for Business, Energy & Industrial Strategy, *Carbon Capture, Usage, and Storage: Dispatchable Power Agreement business model summary* at 16 (Nov. 2022) (CO_2 capture rate longstop date commissioning requirements), https://assets.publishing.service.gov.uk/media/6373993e8fa8f559604a0b8b/ccus-dispatchable-power-agreement-business-model-summary.pdf.

[60] Net Zero Teesside Power Ltd. And Low Carbon Contracts Company LTD Agreement Relating to Net Zero Teesside Power at 29 (Nov. 19, 2024), https://perma.cc/9EXR-LMX5; UK Environment Agency, *Permit with introductory note*, Permit no. EPR/PP3501LR, at 20 (Table S1.3) *available at* https://www.gov.uk/government/publications/ts10-5qw-net-zero-teesside-power-limited-environmental-permit-issued-eprpp3501lra001.

[61] *Infra* Appendix Table 3.

[62] Global CCS Institute, *Collaborating for a Net-Zero Future* at 45 (2024) (https://www.globalccsinstitute.com/wp-content/uploads/2024/11/Global-Status-Report-6-November.pdf (hereinafter "Global CCS Report") [Attachment A].

approximately eight post-combustion capture projects in China are already operational, six of which are on power generation, with four more on the way.[63]

Table 3. International examples of proposed CCS plants in the power sector

Project	**Generating capacity**	**CO_2 captured**	**Capture technology**	**Target capture rate**	**Notes**
Glacier Phase 2, Alberta Canada[64]	15 MW	160,000 metric tons/year	Entropy	Over 90%	New gas turbine, Under construction
UnderPeterhead, UK[65]	910 MW	1.5 to 2 million metric ton/year	MHI	95%	New NGCC, FEED underway
Keadby, UK[66]	910 MW	1.5 million metric ton/year	Aker	95%	New NGCC, FEED underway
Net-Zero Teesside, UK[67]	742 MW	Up to 2 million metric tons/year	Shell Cansolv	95%	New NGCC, under construction
VPI Immingham CHP[68]	1,240 MW	Up to 3 million metric tons/year	Shell Cansolv	Up to 95%	NGCC retrofit, FEED underway
Connah's Quay Low Carbon Power project, UK[69]	1,100 MW	Up to 3.7 million metric tons/year	Shell Cansolv	At least 95%	New NGCC, FEED underway

[63] Nathan Bongers, Low Emission Technology Australia, *China's impressive strides towards carbon capture, utilization, and storage (CCUS)* at 36, 42–43 (May 2025) [Attachment D].

[64] Entropy, *Glacier Gas Plant: Phase 2 Under Construction*, https://perma.cc/3SRG-9SVS.

[65] SSE Thermal, *Peterhead Carbon Capture Power Station: Powering on for a net zero Scotland*, https://www.ssethermal.com/flexible-generation/development/peterhead-carbon-capture/ (last visited Aug. 4, 2023); *see also* Mitsubishi Heavy Industries, *MHI and MHIENG Awarded FEED Contract Relating to a GTCC Power Plant and CO_2 Capture Plant for a Power Station in Scotland* (Aug. 30, 2022), https://www.mhi.com/news/22083001.html.

[66] SSE Thermal, *Keadby 3 Carbon Capture Power Station, Capturing the potential of the Humber*, https://perma.cc/SMF2-FQY6 (last visited Aug. 6, 2025).

[67] Net Zero Teesside & NZT Power, *Net Zero Teesside Power*, https://perma.cc/UN7M-S97U (last visited Aug. 6, 2025).

[68] Shell Global, *Shell's Cansolv CO2 Carbon Capture Technology at VPI Immingham* (Feb. 3, 2022), https://perma.cc/257L-LSEQ.

[69] Enerdata, *Uniper Moves Ahead With Its 1.1 GW Connah's Quay CCGT + CCS Project (UK)* (Jan. 24, 2024), https://perma.cc/QA86-SQ9G; Uniper, *Project Overview* https://perma.cc/24F5-AT3R; Technip Energies, *Technip Energies Selected by Uniper* (Jan. 23, 2025), https://perma.cc/TT8R-YQKE.

Staythorpe, UK[70]	1,850 MW	3.7 million metric tons/year	Not announced	95%	NGCC retrofit, feasibility study completed

C. Permits

CCS is demonstrated, economical, and available on power plants, as further evidenced by companies that are applying for and receiving air permits to build it at scale. These at-scale permits are a recent development. All were filed in 2023, within a year of enacting the IRA 45Q tax credits valued at $85/ton for saline storage and $60/ton for EOR, the latter value which has now increased to $85/ton as well. These air permit applications include the following CCS retrofits:

- Deer Park NGCC in Harris County, Texas. Deer Park is a 1116 MW NGCC plant. Carbon capture equipment will remove 5 million tons/year, 95 percent of the CO_2 emitted from all five steam turbines at the facility. CCS equipment will be constructed in two trains consisting of "(1) Two Quencher columns, where flue gas is conditioned and prepared for the absorption process; (2) Two Absorber columns, where CO_2 is absorbed into the solvent through a chemical reaction; and (3) one Regenerator (or stripper) vessel, where the concentrated CO_2 is released and the original solvent is recovered and recycled back through the process." The Texas Commission on Environmental Quality (TCEQ) received the application for the permit on February 7, 2023 and issued it on March 23, 2023.[71]

- Quail Run NGCC in Ector County, Texas. Quail Run Energy Center is a 550 MW plant. Carbon capture will remove about 1.5 million tons/year of CO_2. TCEQ received the application for the carbon capture plant permit on June 23, 2023 and issued it on February 2, 2024.[72]

- Baytown NGCC in Chambers County, Texas. The Baytown facility is 810 MW, consisting of "three Westinghouse 501F CTG turbines with duct fired HRSGs, two auxiliary boilers, one steam turbine generator and ancillary equipment. Each of the three existing turbines are nominally rated between 170 and 190 MW based upon ambient conditions." The plant will use two CCS trains to capture from the three combustion turbines. The capture equipment is designed to remove 95 percent or more of the flue gas

[70] Staythorpe Power Station, *EIA Scoping Opinion: variation to section 36 consent, Electricity Act 1989* (Jul. 31, 2024), available at https://perma.cc/WA3Z-CQ69; Kelly Nye, RWE, *RWE enters partnership with Harbour energy to explore CCS opportunities at UK power stations* (Dec. 20, 2022), https://perma.cc/8CUF-R4ZA; Kelly Nye, RWE, *RWE announces development proposals for three new carbon capture projects across the UK* (May 23, 2023), https://perma.cc/6YED-J4W8.

[71] Tex. Comm'n on Env't Quality (TCEQ), Online Records Search for Deer Park Permit Documents, https://perma.cc/83F7-KHSA (last visited Aug. 6, 2025).

[72] TCEQ, AirPermits IMS - Project Record for Project # 359380, https://perma.cc/T98B-QDML (last visited Jul. 11, 2025); EPA, *Facility Information: Quail Run Carbon Capture Plant*, https://perma.cc/XC9W-DCNF (last visited Aug. 6, 2025).

it treats, up to 2 million tons/year CO_2. TCEQ received the application for the permit on April 13, 2023 and issued it on May 12, 2023.[73]

- Milton R. Young coal plant in Oliver County, North Dakota. The capture system will capture CO_2 from both units (250MW, 455MW) of the Milton R. Young station. It is designed to remove 13,000 short tons of CO_2 per day. The actual capture from each unit will vary, but could capture 100 percent of unit 1 and 57 percent of unit 2 or 100 percent of unit 2 and 25 percent of unit one. It is designed to remove 95 percent of the CO_2 in flue gas treated. The application was filed on June 2, 2023 and the permit granted on December 29, 2023.[74]

All four projects took less than eight months from permit application to approval. Both Deer Park and Baytown were issued as minor modifications less than two months after filing their applications. The rapid approval of these permits supports the view that CCS can be installed on new NGCC units and existing coal units by 2032.

D. Vendors

Further underscoring the efficacy and availability of carbon capture technology are the guarantees made by the many companies that now offer it. Among the providers of post combustion carbon capture are: Aker Carbon Capture, Aqualung Carbon Capture, BASF Group, BP PLC, Carbon Clean Ltd., C-Capture, Entropy Inc., Fluor Corporation, Honeywell UOP, ION Clean Energy, Inc., Mitsubishi Heavy Industries Ltd., Saipem S.p.A., Shell (CANSOLV), and Svante, Inc. As evidenced by the diversity of vendors listed in Tables 2 and 3, many of these are in a position to bid for large-scale commercial projects in the power sector, typically offering high capture rates of at least 90 percent, and more commonly 95 percent. Since 2012, many of these leading carbon capture solvent providers (including SLB Capturi, Cansolv, Fluor, ION, Carbon Clean, MHI) have carried out major test campaigns on combined cycle flue gas at Technology Centre Mongstad (TCM, Norway), at the scale of 80 metric tons per day. Recent test campaigns have included demonstrations of CO_2 capture with flexible plant operation.[75]

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[73] TCEQ, Online Records Search for Baytown NGCC Permit Documents, https://perma.cc/68SM-SRNB (last visited July 11, 2025).

[74] N.D. Dep't Env't Quality, Online Records for DCC East Project LLC Application Documents, https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents (last visited July 11, 2025).

[75] *Infra* Appendix VIII.

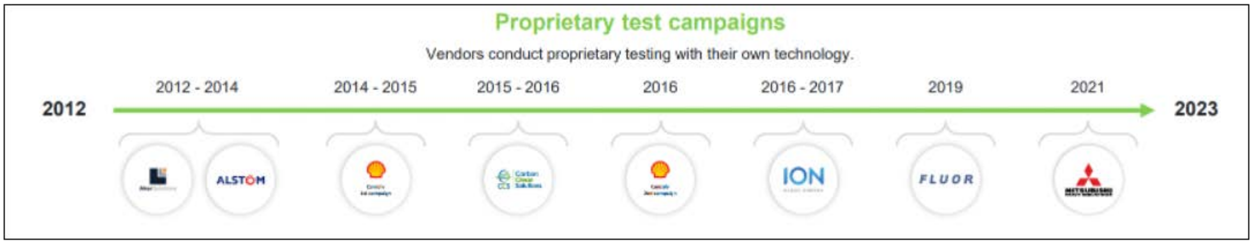

Figure 1. Test campaigns by various capture technology vendors on combined cycle flue gas and fluid catalytic cracker flue gas at Technology Centre Mongstad[76]

E. Capture Rates

Techno-economic analysis also indicates that very high levels of CO_2 capture are technically proven and cost reasonable on gas and coal power plants. The 90 percent benchmark capture rate targeted by many projects until recently has largely emerged by convention as an economically reasonable level of abatement, but does not represent a technical limitation or even an economic optimum for solvent-based capture technology.[77] Increasing the capture rate of these processes typically requires additional absorber height (to prolong the reaction period between flue gas and solvent), and slightly increased desorber temperatures (to reduce the CO_2 loading in the 'lean' or CO_2-stripped solvent). These systems can reach zero net fossil CO_2 emissions (or 100 percent 'effective capture') at around 99.1 percent capture from an NGCC and 99.7 percent capture from a coal plant, as a small portion of CO_2 in the treated flue gas is from the air used in combustion. Beyond these rates of capture, the incoming air used to supply oxygen to the combustion exceeds the CO_2 concentration of the exhaust from the capture system, leading to net decreases in CO_2 from system operation.

Earlier studies of the costs of reaching high (above 95 percent) capture rates already identified relatively small increases in the cost and energy required. For example, Feron et al. (2019) showed that increasing the effective CO_2 capture rate of a solvent-based capture system (30 percent wt MEA) from 90 percent to 100 percent would give a 1.5 percentage point reduction (34.5 percent to 33 percent) in thermal efficiency on a LHV basis for a ultra-supercritical coal fired power plant, and a 2.2 percentage point reduction for a natural gas fired combined cycle (48.6 percent to 46.4 percent LHV).[78] Hirata et al. (2020) investigated a 99.5 percent capture rate for a 650 MWe coal-fired power plant using MHI's KS-1 solvent, finding that a near 100 percent effective capture rate could be achieved with a 3 percent increase in the total annualized cost of CO_2 Capture (\$/ton CO_2).[79] A techno-economic analysis conducted by NETL for 660-MW

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[76] *Wood Report* [Attachment H] at 17, figure 11.

[77] Patrick Brandl et al., *Beyond 90% capture. Possible, but at what cost?*, 105 Int'l J. Greenhouse Gas Control (Feb. 2021), https://doi.org/10.1016/j.ijggc.2020.103239.

[78] Paul Feron et al., *Towards Zero Emissions from Fossil Fuel Power Stations*, 87 Int'l J. Greenhouse Gas Control 188, 200 (2019), https://perma.cc/KB26-MMLK.

[79] Stavros Michailos & Jon Gibbins, *UPCC: Ultra-High Post-Combustion CO2 Capture, CO-CAP: Collaboration on Commercial Capture* (Apr. 13, 2021), https://perma.cc/6JRQ-WUH8.

(gross) NGCC plants found efficiency penalties of 6.4 and 6.6 percentage points for 95% and 97% capture cases, respectively, relative to an unabated plant. This is a marginal increase when compared with the 6 percent increase found for the 90 percent capture.[80] The 97 percent capture case incurs a 2.8 percent increase in LCOE relative to 90 percent capture.[81]

Recent research indicates that operating at very high capture rates (98 percent and greater) can incur a negligible energy or cost penalty, if the plant is appropriately designed and operated.[82] Many previous investigations of high capture rates have failed to optimize solvent lean loading, or to ensure that reboiler temperature and pressure are optimized to prevent significant energy loss from the solvent regenerator as uncondensed steam. Increased operational and research experience with amine capture has enabled significant advances in our understanding of ultra-high capture rates. Mullen and Lucquiaud (2025) found that operating at a low lean solvent loading (the proportion of CO_2 remaining with the solvent after regeneration) and additional packing height on the absorber column enables 100 percent of fossil CO_2 to be captured from a gas-fired power plant (equivalent to 99.1 percent overall capture rate), with only a 2 percent increase in levelized cost of electricity (Figure 2).[83] The authors note that failure to optimize lean loading and reboiler pressure is the likely reason why some previous studies have determined much steeper increases in cost penalty beyond 95 percent capture rates. This modelling result has been tested at the large (50 metric tons per day) CO_2 capture pilot at Haifeng power plant in China, where 97–99 percent capture was achieved with low additional energy requirements.[84]

As indicated by the FEED studies and commercial projects listed in Tables 2 and 3, a range of commercial capture technology vendors now explicitly offer capture rates of over 90 percent. For example, Shell advertises that its CANSOLV technology can remove up to 99 percent of CO_2 from a flue gas stream, and it captures at an average rate of about 90 percent.[85] Likewise, MHI advertises that its KM CDR process and proprietary KS-1 solvent recovers more than 90 percent of CO_2 from the target gas.[86] MHI have stated that their improved KS-21 solvent can increase capture rate from 90 percent to 95 percent with a small reduction in overall costs, once process

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[80] Sarah Leptinsky et al., *Cost and performance estimates for state-of-the-art and advanced 1x1 H-class natural gas-fired power plants*, DOE/NETL-2024/4444 (2024), https://doi.org/10.2172/2376908 [Attachment K].

[81] *Id*.

[82] D. Mullen & M. Lucquiaud, *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO2 capture,* 11 Energy Reports 5104-5124 (June 2025), https://doi.org/10.1016/j.egyr.2024.04.067.

[83] *Id*.

[84] M. Lucquiaud, *Future proofing CCS: Towards zero residual CO2 emissions*, Presentation to Zero Emissions Platform Technology Committee (May 22, 2025) [Attachment L].

[85] *Reducing CO2 emissions in SMR-based hydrogen units*, Shell Catalysts & Technologies, available for download at: https://catalysts.shell.com/en/cansolv-customer-briefing-note-download (last visited Aug. 4, 2023); Ajay Singha & Karl Stéphenne, *Shell Cansolv CO2 capture technology: Achievement from First Commercial Plant*, 63 Energy Procedia 1678 (2014), https://doi.org/10.1016/j.egypro.2014.11.177.

[86] Energy Transition, *CO_2 Capture Technology for Exhaust Gas KM CDR Process*, MHI, https://solutions.mhi.com/ccus/co2-capture-technology-for-exhaust-gas-kmcdr-process/ (last visited Aug. 6, 2025).

optimization and additional absorber packing is applied. Using the same solvent, the technology supplier also offers a 98 percent capture rate at a comparable cost (~2 percent increase relative to 90 percent).[87] Other companies offering similar assurances include BASF/Linde[88] and ION.[89] These vendors have also demonstrated high capture rate operation at various pilot and demonstration sites; units designed for 90 percent capture rate can generally be tested at higher rates simply by reducing flue gas flow and changing other parameters. The Shell Cansolv process has been operated at over 99 percent capture at Boundary Dam 3 and at the pilot-scale at Klemetsrud WtE plant.[90] Pilot tests at the National Carbon Capture Center (NCCC) using piperazine solvent observed capture rates up to 99 percent, with minimal effect of energy requirements per ton of CO_2 captured (<5 percent increase).[91] MHI's improved KS-21 amine solvent has been successfully tested at 95 to 98 percent at Technology Centre Mongstad (TCM).[92] Capture levels in the range 95 to 99 percent were also observed in pilot-scale tests at TCM using open source solvents MEA and CESAR1 solvents.[93] Capture rates of 95-98 percent were demonstrated on a flue gas stream from Niederaussem coal power plant in Germany, using the CESAR-1 solvent.[94] These pilot-scale tests are unlikely to have been designed or optimized for these high CO_2 capture rates, but nonetheless demonstrate a roughly linear relationship between costs and capture rate, as opposed to the exponential increase supposed in some earlier work. This result appears to be consistent across all investigated solvents.

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[87] Ahito Otani, *Achievement of ENI Raenna CCS and Next CO_2 Capture Plant Expectation, Presentation at ZEP Projects Network*, Bologna, Italy (June 24–25, 2025) [Attachment I].

[88] BASF & Linde, *Carbon capture, storage and utilization* (2019), https://perma.cc/RK9F-DVEA.

[89] Andy Awtry, ION Clean Energy, *Design and costing of ION's CO2 capture plant retrofitted to a 700 MW coal-fired power plant* (2021), https://perma.cc/XES5-H7QN.

[90] Brent Jacobs et al., *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities* (2022), https://dx.doi.org/10.2139/ssrn.4286430; Truls Jemtland, *Positive test results from the carbon capture and storage pilot in Oslo,* Fortum: ForTheDoers Blog, (Dec. 13, 2019), https://www.fortum.com/about-us/blog-podcast/forthedoers-blog/positive-test-results-carbon-capture-and-storage-pilot-oslo.

[91] Tianyu Gao et al., *Demonstration of 99% CO2 Removal From Coal Flue Gas by Amine Scrubbing*, 14th Greenhouse Gas Control Technologies Conference Melbourne (GHGT-14) (Oct. 2018), https://dx.doi.org/10.2139/ssrn.3365961.

[92] MHI, *Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New "KS-21TM" Solvent for CO_2 Capture* (Oct. 19, 2021), https://perma.cc/7EFX-QZ3X.

[93] Muhammad Shah et al., *CO_2 Capture from RFCC Flue Gas with 30w% MEA at Technology Centre Mongstad, Process Optimization and Performance Comparison*, 14 International Conference on Greenhouse Gas Control Technologies, GHGT-14 (Oct. 2018), https://dx.doi.org/10.2139/ssrn.3366149; Christophe Benquet et al., *First Process Results and Operational Experience with CESAR1 Solvent at TCM with High Capture Rates (ALIGN-CCUS Project)*, Proceedings of 15th Greenhouse Gas Control Technologies Conference 15-18 (Mar. 2021), https://dx.doi.org/10.2139/ssrn.3814712.

[94] P. Moser, et al., *ALIGN-CCUS: Results of the 18-month test with aqueous AMP/PZ solvent at the pilot plant at Niederaussem – solvent management, emissions and dynamic behavior*, Int. J. Greenh. Gas. Control 109 (2021), https://doi.org/10.1016/j.ijggc.2021.103381.

The feasibility of high capture rates is further reflected in the UK's Environment Agency's permitting requirements for CCS power plants, which require at least 95 percent capture on an annual average basis.[95] As noted above, the Net Zero Teesside Power project is designed to achieve 96 percent capture rate.

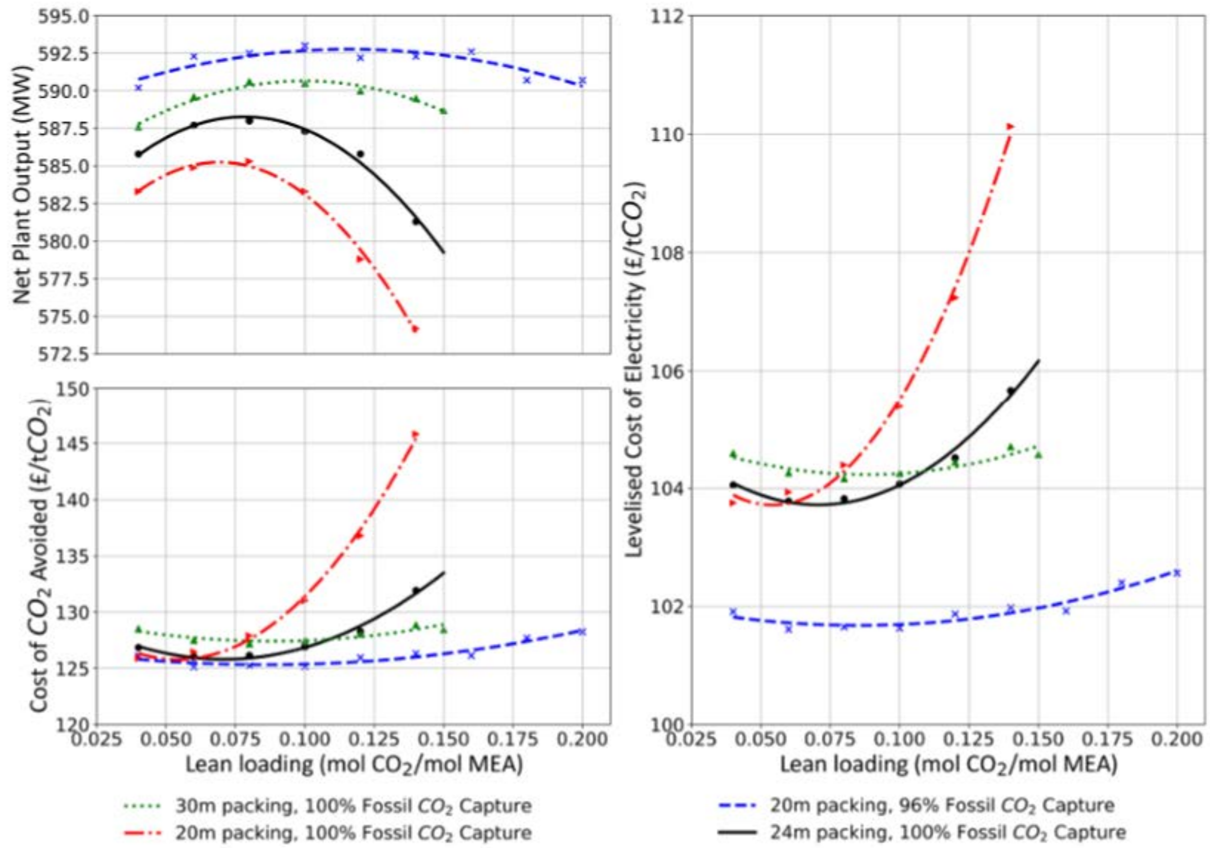

Figure 2. Achieving 100% fossil CO_2 capture rate (99% gross capture) while optimizing cost and energy penalty.[96]

F. Deployment of Carbon Capture in Other Industries

In recent years, there has been particular emphasis on the application of CCS to heavy industry sectors, such as cement, steel, refining, fertilizers and petrochemicals. Many of these sectors include emissions sources which are very costly or impossible to abate by means other than carbon capture and storage. Some industrial sources of CO_2 produce streams with higher CO_2 concentrations and fewer impurities than power plant emissions, and therefore represent the

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[95] *See* UK Environment Agency, *Post-Combustion Carbon Dioxide Capture: Emerging Techniques* (Jul. 2, 2021), https://perma.cc/D8XS-FTSQ.

[96] D. Mullen & M. Lucquiaud, *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO2 capture,* 11 Energy Reports 5104-5124 (June 2025), https://doi.org/10.1016/j.egyr.2024.04.067.

majority of experience with large-scale carbon capture and storage to date. These include natural gas processing, bioethanol, fertilizer production, and hydrogen production (typically for oil refinery applications). These sectors have been pivotal in developing the wealth of commercial experience with CO_2 separation technologies - particularly amine-based solvents - which are now being more widely applied to the power sector.[97] Amine-based solvents were first applied to the removal of CO_2 from natural gas in the 1930s and are routinely used in the production of ammonia-based fertilizers. The Quest CCS project in Alberta, Canada, has used an amine-based process (monodiethanolamine) to remove CO_2 produced during the production of hydrogen from methane and other hydrocarbon gasses. Since 2015, the plant has consistently captured its targeted 1 to 1.2 million metric ton (Mt)/year of CO_2, with an average capture rate of 79 percent (design target is 80 percent) over the first six years of operation.[98]

Experience with such large-scale amine CO_2 capture plants, even with different process gas streams, is highly applicable to the scale up of similar processes in the power sector. This is because using amines to capture CO_2 from flue gas is fundamentally the same process in both cases. Adapting existing amine-based capture technologies to power sector applications involves making adjustments to process parameters such as absorber height, reboiler energy demand, and CO_2 loading in the solvent loading, in accordance with differences in the pressure and CO_2 concentration of the target gas stream (Figure 3).[99] Appropriate upstream cleaning of the gas stream is also necessary to remove any species that can negatively affect the amine process.[100]

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[97] *See Wood Report* [Attachment H].

[98] Shell Canada Energy, *Quest Carbon Capture and Storage Project Annual Summary Report*, Alberta Department of Energy 2021 (Mar. 2022), https://perma.cc/H8YH-D46U.

[99] *Wood Report* at 8 [Attachment G].

[100] *Infra* Section V (co-benefits discussion).

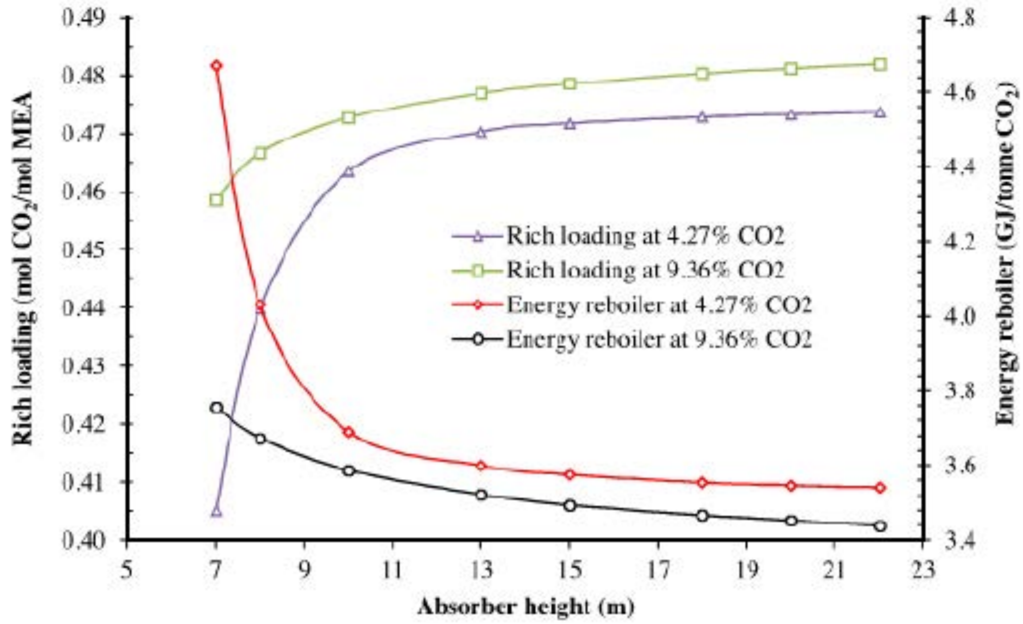

Figure 3. Impact of CO_2 loading on reboiler energy and rich loading for two different flue gas compositions

Amine solvent-based processes are now being applied to a range of other industrial emission sources at commercial scales, many of which treat process streams with similar composition to that of a coal or gas-fired power plant. In the cement sector, capture of 400 kt/year from the Brevik cement plant in Norway commenced operations in July 2025 using SLB Capturi's amine solvent;[101] capture of over 1000 kt/year from a plant in Edmonton is expected from 2026;[102] and 800 kt/year from Padeswood Cement in the UK is expected from 2028.[103] In Europe, there is also considerable interest in applying CCS at heat and power plants fired with waste or biomass fuel. For example, Klemetsrud waste-to-energy plant in Norway has begun construction on a 90 percent capture unit (from SLB Capturi),[104] while two biomass-fired CHP plants in Denmark are

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[101] Heidelberg Cement, *Brevik CCS – Carbon Capture at Norcem Brevik*, UNECE CCS-Panel (Mar. 25, 2022) Heidelberg Materials, *Official opening of Brevik CCS – 17-19 June 2025* (June 17, 2025), https://www.brevikccs.com/en/node/522844; Tanya Weaver, *Norway's industrial-scale CCS plant to capture 400,000 metric tons of CO2 annually*, Engineering and Technology (Dec. 4, 2024), https://eandt.theiet.org/2024/12/04/norways-industrial-scale-carbon-capture-plant-suck-400000-metric-tons-co2-annually.

[102] Heidelberg Materials Press Release, *First global net-zero carbon capture and storage facility in the cement industry: Heidelberg Materials partners with the Government of Canada* (Apr. 6, 2023), https://www.heidelbergmaterials.com/en/pr-2023-04-06.

[103] Mitsubishi Heavy Industries Press Release, *MHI and Worley Awarded FEED Contract for UK's First CO_2 Capture Plant at a Cement Production Facility* (Feb. 6, 2024), https://www.mhi.com/news/24020601.html

[104] Reuters, *Norway Resumes Work on Oslo Waste Carbon Capture Project* (Jan. 27, 2025), https://www.reuters.com/sustainability/norway-resumes-work-oslo-waste-carbon-capture-project-2025-01-27/.

also under construction.[105] Numerous other projects in these sectors and others are in earlier stages of planning.[106] In addition to Quest and two other operational pre-combustion CCS projects in Alberta, Canada, a number of post-combustion CCS projects are in various stages of development. Currently under construction and scheduled to being operating in 2028, Shell's Polaris project will capture 650 kt/year of CO_2 from the gas-fired furnaces at the Scotford Refinery.

Besides contributing to technical and commercial experience with CO_2 capture, the deployment of CCS on non-power sources is relevant to the power sector as it will seed and accelerate the development of CO_2 transport and storage networks. Many lower-cost capture sources (e.g., ethanol, hydrogen) will deploy CCS first, helping to build out CO_2 pipeline networks and storage sites which can also be shared by power plants equipped with CCS.

II. Availability of Geologic Sequestration

A. Geologic Storage Has Been Thoroughly Demonstrated

There is a long history of successful injection and retention of CO_2 as well as a variety of other gasses and liquids into geologic formations. These demonstrate that CO_2 can be safely and permanently stored in porous geologic formations below impermeable cap rocks.

Injection of gasses into saline aquifers, salt domes, and depleted gas zones have been routine for decades as a part of America's natural gas storage program. In fact, natural gas storage goes back for over a century, as it was originally tested in 1915.[107] The National Petroleum Reserve system now safely contains and maintains 3 trillion cubic feet of injected gas in the subsurface on an annual basis.[108] Natural gas storage in geologic formations is, in fact, widespread, with natural gas storage facilities in 30 states, in approximately 400 facilities nationwide, with a combined capacity of about 4 trillion cubic feet of natural gas. Eighty percent of the deep geologic natural gas storage capacity is in depleted oil and gas formations- which themselves are porous formations containing hydrocarbon-bearing saline brines, 10 percent in saline brine-only aquifers, and 10 percent in salt formations.[109]

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[105] Orsted, *Orsted Begins Construction of Denmark's First Carbon Capture Project* (Apr. 12, 2023) https://orsted.com/en/media/news/2023/12/oersted-begins-construction-of-denmarks-first-carb-13757543.

[106] Clean Air Task Force, *Europe Carbon Capture Activity and Project Map*, https://www.catf.us/ccsmapeurope/ (last visited Aug. 6, 2025).

[107] *See* NETL, *Underground Natural Gas Storage – Analog Studies to Geologic Storage of CO_2* (Jan. 24, 2019), https://perma.cc/85KA-WVUN.

[108] EIA, *Weekly Natural Gas Storage Report* (last released July 31, 2025), https://perma.cc/ZA7J-4JZN .

[109] API, *Underground Natural Gas Storage* (2021), https://www.energyinfrastructure.org/energy-101/natural-gas-storage.

Liquid injection into geologic formations has a similarly long history. Billions of tons of liquid waste are disposed of into saline aquifers annually.[110] There are approximately 150,000 injection wells in the U.S. in use for disposal of municipal wastewater, produced fluid brine waste from natural gas storage, unconventional gas production and brines produced during EOR.

And, geologic storage of CO_2 is a well-understood practice in the U.S. and worldwide, with commercial operations dating back to the 1970s. To date, in the U.S. alone, over 31 Mt of CO_2 emissions have been safely and permanently stored in deep geologic formations regulated under EPA's Underground Injection Control authority, and monitored under Clean Air Act Greenhouse Gas Monitoring and Reporting requirements.[111]

Additionally, geologic storage of CO_2 into saline aquifers is in use in the U.S. and globally. The first commercial-scale saline storage project in the world, dating back to 1996—Sleipner in Norway—has stored approximately 1 Mt of captured CO_2 annually for over 20 years in deep geologic formations beneath the North Sea.[112] The Sleipner project's multi-decade record of geologic storage provides precedent that deep geologic storage of commercial volumes of captured CO_2 can be effectively and safely performed. Domestically, the two Decatur saline storage projects provide proof that carbon storage is available at commercial scale. The Illinois Basin Decatur Project has successfully and securely stored over 1 million metric tons of CO_2 into the Mount Simon sandstone formation in the Illinois Basin. The sister project, the Illinois Industrial CCS project, is currently underway injecting and storing commercial-scale volumes of CO_2 each year, with a five-year permit to inject 5.5 Mt over the life of the project.[113] This experience with storage of CO_2 in saline formations is further supported by the decades of successful experience with injecting CO_2 into existing oil fields as part of the enhanced oil recovery process. As part of the EOR process, approximately 1.4 billion tons of new (and much more recycled) CO_2 has been injected into porous sandstone and carbonate formations containing oil-bearing brines.

B. Storage Opportunities Are Well-Dispersed and Within Reasonable Distance of Gas- and Coal-Fired Power Plants Across the Country

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[110] Elizabeth J. Wilson, Timothy L. Johnson & David W. Keith, *Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage*, 37 Env't Sci. & Tech. 3476 (2003), https://pubs.acs.org/doi/pdf/10.1021/es021038+.

[111] 40 C.F.R. §§ 98.440–.449 (subpart RR).

[112] Anne-Kari Furre et al., *20 Years of Monitoring CO_2-injection at Sleipner*, 114 Energy Procedia 3916 (2017), https://doi.org/10.1016/j.egypro.2017.03.1523.

[113] Press Release, ADM, *ADM Begins Operations for Second Carbon Capture and Storage Project* (Apr. 7, 2017), https://www.adm.com/en-us/news/news-releases/2017/4/adm-begins-operations-f or-second-carbon-capture-and-storage-project/; Scott McDonald, ADM, *Illinois Industrial Carbon Capture & Storage Project: Eliminating CO_2 Emissions from the Production of Biofuels: A 'Green' Carbon Process* (Jul. 11, 2017), https://www.energy.gov/sites/prod/files/2017/10/f38/mcdonald_bioeconomy_2017.pdf.

1. Onshore Geologic Storage

The U.S. has widespread and abundant geologic storage options in deep saline aquifers. Geologic storage of CO_2 is widely available to reduce carbon emissions from fossil fuel-fired power plants and other large point sources. The U.S. Department of Energy (DOE) Carbon Sequestration (NATCARB) Atlas estimates a median storage potential of over 8,000 Gt in saline formations in the U.S., which are spread across multiple sedimentary basins.[114] This estimate of domestic saline storage capacity represents over 5,000 years' worth of emissions from current gas- and coal-fired power plants.[115] The NATCARB Atlas and database are underpinned by two decades of research and demonstration, including hundreds, if not thousands, of technical publications based on millions of tons of CO_2 injected into saline aquifers and depleted oil fields.

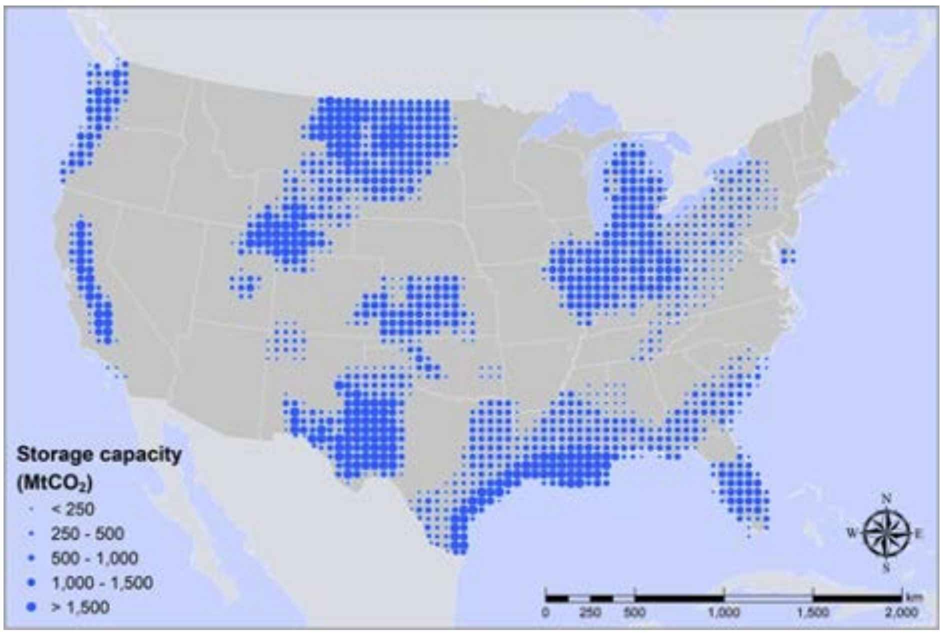

Figure 4. Map developed by Carbon Solutions, LLC using NATCARB data, illustrating generalized saline storage potential in the U.S.[116]

Most U.S. regions have begun to lay the groundwork for more extensive CCS project deployment, with the potential for commercially storing significant CO_2 emissions in deep saline aquifers.

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[114] NETL, DOE, *Carbon Storage Atlas*, Fifth ed. (Sep. 2015), https://perma.cc/9NCE-KDMH.

[115] Based on EIA State Electricity Profiles data, Table 7 (2023 data) https://www.eia.gov/electricity/state/unitedstates/state_tables.php.

[116] Carbon Solutions, LLC, *Clean Air Task Force: Final Report* at 13 (Sept. 22, 2022) [Attachment M].

Table 4. NATCARB saline storage capacities and number of CarbonSAFE projects within each U.S. storage region as defined by the Regional Carbon Sequestration Partnership initiatives

	United States Storage Regions								
	Big Sky	Midwest	Midwest/Mid-Atlantic	Plains	Southeast	Southwest	West Coast	Other Non-RCSP Region	Total
States Included	ID, MT, and WY	IL, IN, and KY	MD, MI, NJ, NY, OH, PA, and WV	IA, MN, MO, ND, NE, SD, and WI	AL, AR, FL, GA, LA, MS, NC, SC, TN,	AZ, CO, KS, NM, OK, West TX,	CA, NV, OR, and WA	AK, CT, DC, DE, HI, MA, NH, RI, VT,	
NATCARB Atlas V CO2 Saline Storage Medium Resource Estimate (Gt)	805	163	122	583	5,257	1,000	398	not estimated	8,328
CarbonSAFE Phase I, II, and III Projects	4	4	2	5	4	3	2	-	24

Saline storage opportunities are widespread across the U.S. and much of the existing fossil fuel-fired power plants are located on top of or in proximity to sedimentary basins with significant saline storage capacity. Figure 5 shows generalized saline storage capacity with existing coal and natural gas-fired power plant locations superimposed (137 coal plants, totaling 603 $MtCO_2$/yr; 293 natural gas plants totaling 444 $MtCO_2$/yr). This map is overinclusive and includes many more plants than are subject to CCS-based Carbon Pollution Standards. The sources in the map consist of all fossil fuel-fired plants that plan to operate in 2030 and that operate over 30 percent capacity factor.

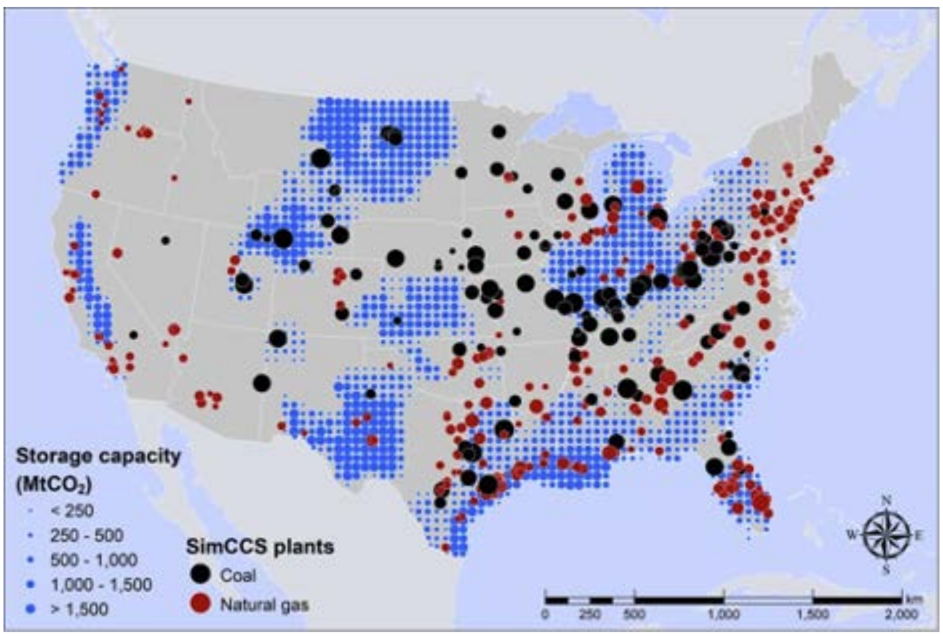

Figure 5. Map of U.S. saline storage capacity with locations of coal and natural gas-fired power plants[117]

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[117] *Id*. at 12-13 [Attachment M].

2. *Offshore Storage*

Additionally, significant saline storage potential has been identified in the offshore Mid-Atlantic region (see Figure 6). Battelle Memorial Institute led a DOE-sponsored consortium to investigate storage opportunities in the Mid-Atlantic offshore region including the Baltimore Canyon Trough and the Georges Banks Basin.[118] The results of the study suggest that deep saline formations in this offshore region may be able to store hundreds of millions to billions of tons of CO_2, which could serve as an important storage resource for fossil fuel-fired power plants in the Northeast region. DOE's Office of Fossil Energy and Carbon Management announced a funding award in 2023 to establish a foundation for a carbon management hub along the Mid-Atlantic Outer Continental Shelf from Northern Virginia to Massachusetts which builds on the previous characterization work performed in this region.[119]

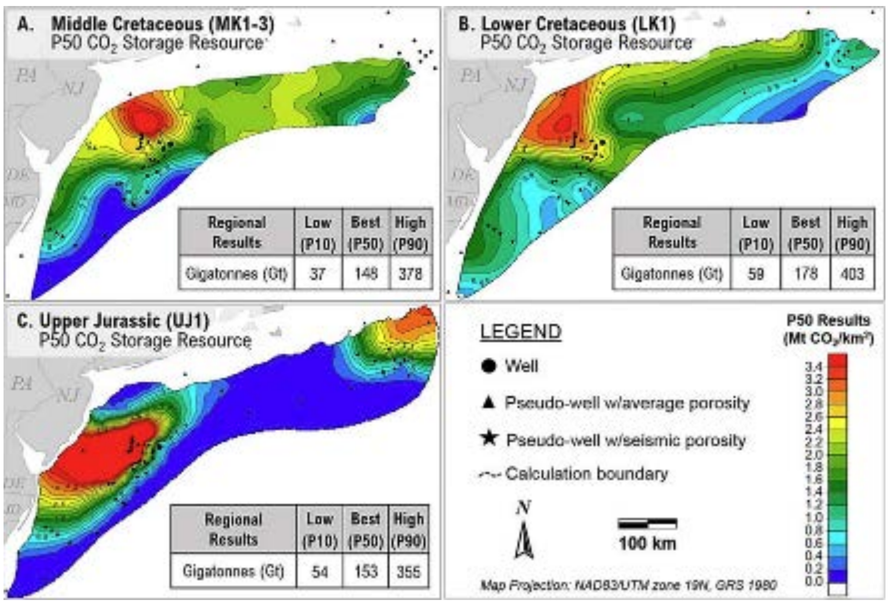

Figure 6. Map of Offshore Storage Capacity in the Mid-Atlantic[120]

CATF-commissioned work by Carbon Solutions, LLC, shows that offshore storage opportunities in the Atlantic extend much further along the Eastern Seaboard (*see* Figure 7), from

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[118] Battelle, *Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment Project (Final Technical Report)* (2019), https://www.osti.gov/biblio/1566748-mid-atlantic-offshore-carbon-storage-resource-assessment-project-final-technical-report.

[119] DOE, OFECM, *Project Selections for FOA 2799: Regional Initiative to Accelerate Carbon Management Deployment: Technical Assistance for Large Scale Storage Facilities and Regional Carbon Management Hubs*, https://perma.cc/RT58-8WRE.

[120] Battelle, *Mid-Atlantic* (2019).

Massachusetts to Georgia, and could serve as an important storage resource for much of the East Coast.[121]

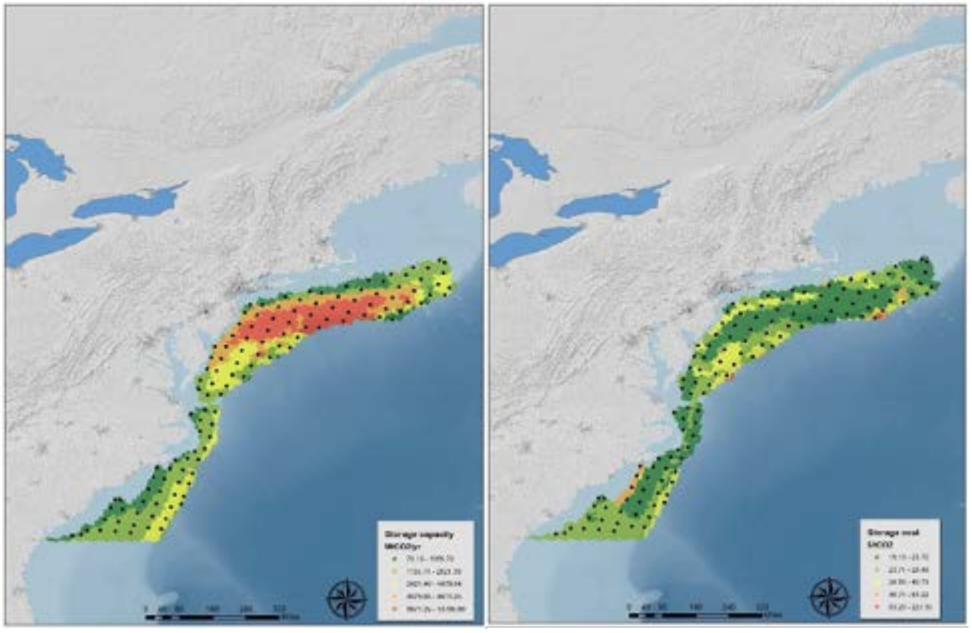

Figure 7. Map of Offshore Storage Capacity Along the Eastern Seaboard.[122]

3. *Storage associated with oil fields*

Carbon dioxide is currently injected into many oil fields for enhanced oil recovery, where the injected CO_2 is stored in the process of injection, production, and recycling. This "incidental" or "associated" storage occurs when CO_2 is trapped in rock pore spaces by the capillary physics process of releasing oil during CO_2 flooding. As of end-of-year 2022, there were approximately 139 CO_2-EOR projects actively injecting CO_2 in the deep subsurface in the U.S.[123] This includes an estimated both 0.4 billion cubic feet per day of industrial CO_2 as well as 1.5 billion cubic feet per day of naturally occurring CO_2 that is mined from underground deposits and transported to currently active EOR projects.[124] This currently-mined CO_2 at existing EOR fields could be replaced with captured CO_2 from power plants. In addition, the United States Geological Survey (USGS) has estimated that there are over 25 billion barrels of oil that are technically recoverable

[121] Carbon Solutions, LLC, *Oceankind: CCS Potential in the US Mid-Atlantic using Offshore Storage* at 7 (May 19, 2023) [Attachment N].

[122] *Id.*

[123] Advanced Resources International, *The U.S. CO_2 Enhanced Oil Recovery Survey* (Feb. 21, 2024), https://perma.cc/JKH9-65X3.

[124] *Id.*

via EOR across 3,500 screened oil reservoirs.[125] Existing oil and gas fields could be used for storage of CO_2 without EOR as well.

C. Significant Investment from DOE Continues to Demonstrate and Validate Large-Scale Storage Opportunities

The U.S. has more CCS activities ongoing and planned than any other country.[126] DOE has invested more than $1 billion through its Carbon Storage Research and Development Program to develop the technologies and capabilities for widespread commercial deployment of geologic storage.[127] Some of the selected programs and initiatives include the Regional Carbon Sequestration Program (RCSP),[128] more recently initiated Regional Initiatives to accelerate CCS deployment,[129] the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative,[130] the NATCARB Carbon Storage Atlas,[131] efforts to characterize storage potential and prospects in the offshore Gulf of Mexico,[132] and is considering establishment of a multi-year field-based research and development initiative named Carbon Storage Technology Operations and Research (CarbonSTORE).[133] The result of this work has demonstrated that the U.S. likely has some of the most abundant geologic potential for storage of any country in the world.

In late 2016, in a follow-up to the successful decade-long RCSP effort, DOE initiated a new phase of its efforts to advance carbon storage technology by launching the CarbonSAFE program. The CarbonSAFE program was initially awarded $44 million to support and promote the development of carbon storage sites with the potential to store over 50 Mt of CO_2 by 2026,

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[125] *See* USGS, *National Assessment of Carbon Dioxide Enhanced Oil Recovery and Associated Carbon Dioxide Retention Resources—Summary* (Jan. 2022), https://perma.cc/46TF-QE2V.

[126] *See* CATF, *U.S. Carbon Capture Activity and Project Map*, https://www.catf.us/ccsmapus/.

[127] NETL, *Safe Geologic Storage of Captured Carbon Dioxide: Two Decades of DOE's Carbon Storage R&D Program in Review* (Apr. 13, 2020), https://perma.cc/4YLM-26X7.

[128] NETL, *Regional Carbon Sequestration Partnership (RCSP)*, https://perma.cc/RH26-YSNC.

[129] DOE, OFECM, *FOA 2000: Regional Initiative to Accelerate CCUS Deployment*, https://perma.cc/6PTL-3Z63 (last visited Aug. 7, 2025).

[130] NETL, *CarbonSAFE Initiative*, https://perma.cc/M7BG-246R (last visited Aug. 7, 2025).

[131] NETL, *NATCARB/Atlas*, https://perma.cc/4VV3-CCTE (last visited Aug. 7, 2025).

[132] Gulf Coast Carbon Center, *GoMCarb*, https://www.beg.utexas.edu/gccc/research/gomcarb (last updated May 20, 2025); Southern States Energy Board, *SECARB Offshore*, https://www.sseb.org/programs/offshore/ (last visited Aug. 7, 2025).

[133] NETL, *DOE Seeks Information on Developing Carbon Storage Field Laboratories* (Dec. 2, 2022), https://perma.cc/U5RS-3NPY.

building on learnings from the RCSP program.[134] The program is comprised of four phases, covering pre-feasibility through construction.

The CarbonSAFE projects, building off of results of the decade-long NETL RSCP program, have already begun to publish important findings, most importantly, the potential for vast regional, and inexpensive ($2 to $4/ton) sequestration hub at the Kemper County, Mississippi site (ECO2S), and the Illinois Basin Decatur Project (IBDP)—demonstrating that large saline storage aquifers are readily available for storage in the Midwest and Southeast:

Project ECO2S in Kemper County, Mississippi is a DOE- and Southern Company-supported CarbonSAFE initiative with the goal of developing a commercial scale CO_2 storage site. Southwest regional development began with the initial characterization of potential storage formations done by the NATCARB Atlas initiative and the Plant Daniel pilot project in Mississippi, which successfully injected 3,000 metric tons of CO_2 and developed characterization, permitting, public outreach, injecting and monitoring methodologies. The RCSP Citronelle deployment project in Alabama built on the knowledge base established at the Plant Daniel project to further prove the feasibility of CO_2 storage in the gulf coast region. These initial efforts provided important knowledge of regionally significant geologic formations, as well as improved techniques and technologies to monitor and model CO_2 storage sites. The Project ECO2S site builds on this operational expertise, technical engineering, and monitoring methodologies, further demonstrating the feasibility of commercial-scale CO_2 storage.

One of the most active regions of carbon storage development has been the Midwest's Illinois Basin. The Mount Simon sandstone has proved to be a world-class storage formation in Illinois through multiple projects conducted by public-private partnerships. Initial Midwest Geological Sequestration Consortium (MGSC) validation phase projects proved CO_2 could be safely injected and stored in regional formations. The Illinois Basin Decatur Project (IBDP), organized by MGSC, followed the validation projects and injected one million metric tons of CO_2 from 2011 to 2014 near the Archer Daniels Midland Company ethanol plant. Lessons learned from the IBDP project led to the Illinois Industrial Carbon Capture and Storage Project (ICCS), which continues to inject commercial volumes of CO_2 annually. This project is further proving the safe storage capabilities of the Mount Simon sandstone and demonstrating the safe and permanent storage of CO_2. The project is also allowing for further improvement of modeling techniques, and other technical knowledge and expertise for commercial-scale storage projects. Currently, DOE is supporting the development of the CarbonSAFE Illinois Storage Corridor, where the goal is to develop a storage project with the capability of injecting 50 million metric tons of CO_2 per year.

These government-supported projects have established the foundation for announced plans for subsequent, commercial-scale projects and have successfully demonstrated commercial-scale storage, while improving our understanding of project screening, site selection, characterization,

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[134] NETL, *CarbonSAFE Initiative*; DOE, *Energy Department Announces More than $44 Million for CO_2 Storage Projects* (Nov. 30, 2016), https://www.energy.gov/articles/energy-department-announces-more-44-million-co2-storage-projects.

baseline monitoring, verification, and accounting, and injection operations. Lessons learned from these projects are being applied elsewhere across multiple sedimentary basins in the U.S., and the additional CarbonSAFE projects that are currently funded, and projects that will be funded in the future, will continue to validate and broaden the availability of commercial-scale storage.

The IIJA provided DOE with $2.25 billion of funding, to be used by FY26 to build on the CarbonSAFE program by providing grant funding for the development of new or expanded commercial large-scale storage projects, including Phase III, III.5, and IV funding for the feasibility, site characterization, permitting, and construction stages of project development. To date, FECM has funded over $1.2 billion in large-scale commercial storage projects from sets of projects announced in May 2023,[135] November 2023,[136] and October 2024.[137] This includes funding for construction of a dedicated, commercial large-scale geologic carbon storage facility to store up to 80 million metric tons of CO_2 in support of Project Tundra.[138]

Additionally, in 2019, the Regional Initiative to Accelerate Carbon Capture, Utilization, and Storage Deployment was launched by DOE to identify and address regional storage and transport hurdles affecting commercial deployment of CCS.[139] The regional initiatives build upon the research, expertise, and stakeholder base established by the RCSPs to continue identifying and addressing regional knowledge gaps. Four regional initiatives were originally selected to facilitate and integrate CarbonSAFE projects and commercial efforts within the regions:

- Midwest Regional Carbon Initiative
- Carbon Utilization and Storage Partnership of the Western United States
- Southeast Regional Carbon Utilization and Storage Partnership
- Plains Carbon Dioxide Reduction Partnership

These regional initiatives will further accelerate the commercial-scale deployment of CCS across the U.S. by promoting regional technology transfer, addressing key technical challenges, facilitating data collection, sharing, and analysis, and evaluating existing regional infrastructure.

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[135] DOE, OFECM, *Project Selections for FOA 2711: Carbon Storage Validation and Testing (Round 1)*, https://www.energy.gov/fecm/project-selections-foa-2711-carbon-storage-validation-and-testing-round-1.

[136] NETL, *DOE Invests More Than $444 Million for CarbonSAFE Projects* (Nov 15, 2023), https://netl.doe.gov/node/13090.

[137] NETL, *DOE Invests More Than $518 Million for CarbonSAFE Projects and Issues a Request for Information* (Oct. 21, 2024) https://netl.doe.gov/node/14244.

[138] DOE, OFECM, *Project Selections for FOA 2711: Carbon Storage Validation and Testing (Round 3)* , https://www.energy.gov/fecm/project-selections-foa-2711-carbon-storage-validation-and-testing-round-3 (last visited Aug. 7, 2025).

[139] NETL, *Regional Initiative to Accelerate CCUS Deployment*, https://netl.doe.gov/carbon-management/carbon-storage/regional-initiative-to-Accelerate-CCUS-deployment. (last visited Aug. 7, 2025).

DOE also recently announced project selections for its regional initiative, 16 projects totaling nearly $25 million in DOE funding, under two areas of interest: 1) technical assistance and public engagement for geologic CO_2 storage and transport at large-scale storage facilities or within prospective regional carbon management hubs, and 2) state geological data gathering, analysis, sharing, and engagement.

D. Additional Analysis by Carbon Solutions Shows Feasibility of CCS Deployment by the U.S. Power Sector

1. CCS Is Technically and Economically Viable for the Gas and Coal Fleets

The Carbon Solutions, LLC report titled "National Assessment of Natural Gas Combined Cycle and Coal-fired Power Plants with CO_2 Capture and Storage" commissioned by Clean Air Task Force had as its objective determining the techno-economic feasibility of CCS deployment for the U.S. fossil-fired power fleet and what percentage of the existing fleet has reasonable (technical and economical) access to storage.[140]

The study used SimCCS^{PRO} toolsets to perform a first-of-its-kind advanced source-sink analysis, developing multiple CCS buildout scenarios connecting gas and coal plants to CO_2 storage strictly in onshore saline aquifers. The study was done prior to passage of the Inflation Reduction Act and focused on power plants that were expected at that point to be operational in 2030 and beyond but did not include plants with announced retirements prior to 2030. As a result, the study evaluates the application of CCS at more power plants than are expected to deploy CCS in the model EPA used in developing the Carbon Pollution Standards.

This study also does not provide any specific pipeline locations but instead provides illustrative corridors that link sources and sinks. It is also not a recommendation or expectation that any particular pipeline infrastructure will be built out as each plant owner will determine how to comply with the Carbon Pollution Standards. What the study does is demonstrate that the bulk of the existing gas and coal fleet can technically and economically access sequestration if it is subject to a CCS-based performance standard, and chooses to comply with it through a CCS retrofit. Storage sites were aggregated on a 50 km grid, avoiding urban areas, national parks, and other infeasible surface features.

2. Capture

Carbon Solutions sourced CO_2 capture data (capturable CO_2, number of CO_2 streams, and CO_2 stream purity) from NICO_2LE database that fuses and analyzes CO_2 emissions data from multiple data sources to calculate capturable CO_2. Capture costs for coal and NGCC power plants are derived from Brown and Ung (2019) with lower-bound estimates for Nth-of-a-kind

140 Carbon Solutions, LLC, *National Assessment of Natural Gas Combined Cycle (NGCC) and Coal-fired Power Plants with CO2 Capture and Storage (CCS)* (Sept. 2022) [Attachment O].

plants, assuming a 11 percent capital recovery factor to annualize capital costs.[141] Power plant information was generated from the US EPA Emissions and Generation Resource Integrated Database (eGRID), and power plants were characterized by their dominant fuel type (coal or natural gas). Individual gathering units or entire plants that were due to close before 2030 were excluded from the analysis. Average capture costs across the modeled buildout scenarios ranged from \$68.30 to \$70.37/ton CO_2.

Source Parameters:

- Fuels: All coals, NG
- Min. Capture: 0.5 $MtCO_2$/yr
- Capture Rate: 90 percent
- Retirements: 2030
- Capacity Factor: 30 percent

Sources:

- 429 plants | 1,044 $MtCO_2$/yr
- 136 coal | 600 $MtCO_2$/yr
- 293 NGCC | 444 $MtCO_2$/yr

[141] Jeffrey D. Brown & Poh Boon Ung, *Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S.* (National Petroleum Council, Working Paper 2019), https://dualchallenge.npc.org/files/CCUS%20Topic%20Paper%201-Jan2020.pdf.

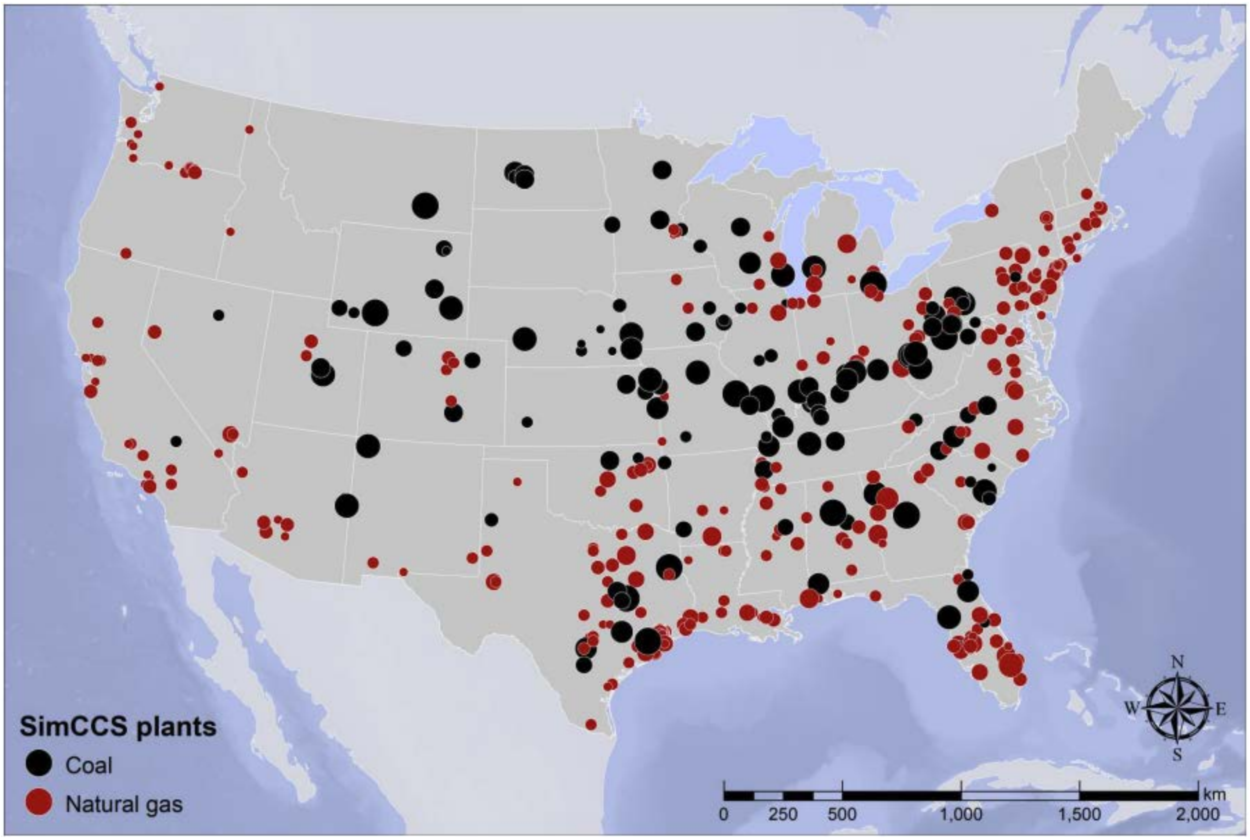

Figure 8. Map showing locations of coal and natural gas-fired power plants used in the Carbon Solutions study.

3. *Transport*

Carbon Solutions identified low-cost and optimized CO_2 pipeline routes for each modeled scenario using its CostMAP pro tool, which develops pipeline routes at multiple resolutions ranging from 30m to 720m grid cells. 720m grid cell resolution was used for this study. Baseline pipeline costs were generated using the latest version of the FECM/NETL CO_2 Transport Cost Model. These costs were updated to 2022 to align with the same dollar-year used for CO_2 capture costs. Average transport costs ranged from \$2.24 to \$8.04/ton CO_2 across the modeled buildout scenarios.

4. *Storage*

Carbon Solutions generated saline storage CO_2 estimates using its SCO_2T^{PRO} tool and database. This tool uses a dynamic injection approach to estimating effective storage capacities, which yields a more advanced estimate of storage potential than the static estimates generated by DOE's NATCARB Atlas. Storage sites were aggregated on a 50 km grid, avoiding urban areas, national parks, and other infeasible surface features. For each 50 km sink where multiple storage formations were present, the "best" reservoir in each stack was selected and used for the cost basis. Only onshore saline aquifers were considered for this study, though there is vast storage potential in offshore saline aquifers and in depleted oil and gas fields. The SCO_2T pro tool was also used to generate advanced storage costs estimates. This tool provides more accurate estimates of storage costs than methods that use volumetric storage estimation (e.g., FE/NETL CO_2 Saline Storage Cost Model) as volumetric approaches (as opposed to dynamic injection approach used in this study) often overestimate the number of required injection wells for a given scenario which leads to significantly inflated cost estimates.[142] Average storage costs estimates for this study ranged from \$8.52 to \$8.76/ton CO_2 across the modeled distributed storage buildout scenarios.

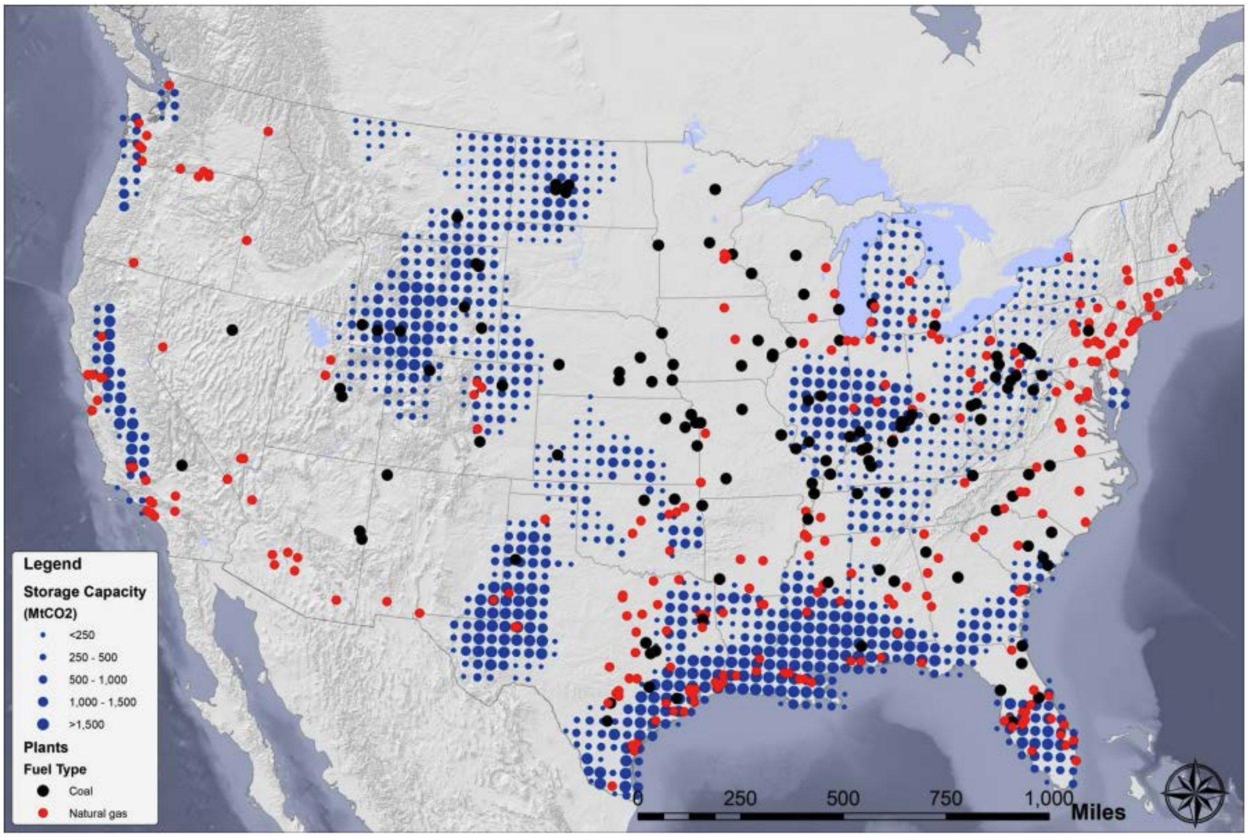

Figure 9. Map of U.S. saline storage capacity with locations of coal and natural gas-fired power plants, from Carbon Solutions study.

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[142] Jonathan D. Ogland-Hand et al., *Screening for Geologic Sequestration of CO_2: A Comparison Between SCO_2T^{PRO} and the FE/NETL CO_2 Saline Storage Cost Model*, 114 Int'l J. Greenhouse Gas Control 103557 (2022), https://www.sciencedirect.com/science/article/pii/S175058362100308X?via%3Dihub.

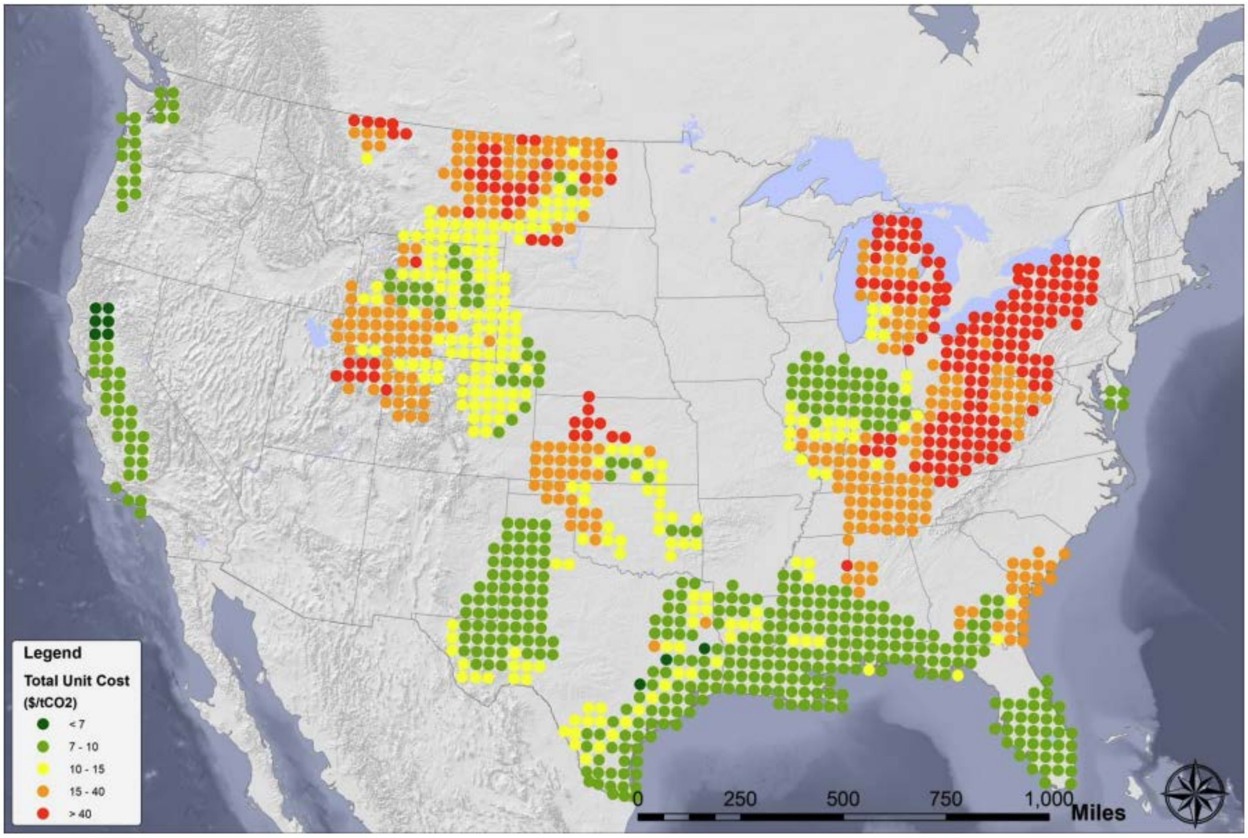

Figure 10. Map illustrating generalized unit costs of saline storage per ton of CO_2 across the U.S., from Carbon Solutions study.

5. *Results*

Optimized CCS buildout scenarios were modeled across a range of capture targets (200, 400, 600, 800, 1,000, and 1,044 $MtCO_2$/yr (representing the emissions from the full set of coal and gas plants modeled)). For each modeled scenario, outputs include:

- Target capture ($MtCO_2$/yr)
- Sources deployed
- Sinks deployed
- Pipeline network length (km)
- Total costs for capture, transport, and storage ($M/yr)
- Per metric ton costs for capture, transport, and storage ($/ton CO_2)

Total CCS buildout costs (capture, transport and storage) ranged from $79.22 to $86.92/ton CO_2 across the modeled buildout scenarios. These results suggest that CCS buildout for the bulks of the existing gas and coal fleets is economically viable and technically feasible considering various cost metrics including the IRS Section 45Q tax credit incentive value of \$85/ton CO_2, the social cost of emitted carbon, and the cost of comparable pollution controls such as FGD. The full report can be found at Attachment M.

Table 5. Summary outputs of national-scale CCS buildout modeling for coal and natural gas-fired power plants

Target ($MtCO_2$/yr)	Sources de-ployed	Sinks de-ployed	Hubs de-ployed	Network length (km)	Total costs (\$M/yr)				Per tonne costs (\$/tCO_2)			
					Total	Capture	Transport	Storage	Total	Capture	Transport	Storage
200	43	32	N/A	2,133	15,844	13,660	449	1,736	79.22	68.3	2.24	8.68
400	102	64	N/A	5,147	32,386	27,610	1,272	3,504	80.97	69.02	3.18	8.76
600	183	96	N/A	9,627	49,338	41,760	2,449	5,129	82.23	69.6	4.08	8.55
800	260	120	N/A	16,064	66,906	55,821	4,228	6,858	83.63	69.78	5.28	8.57
1000	389	142	N/A	27,814	85,989	70,262	7,148	8,580	85.99	70.26	7.15	8.58
1044	429	146	N/A	32,550	90,743	73,462	8,391	8,890	86.92	70.37	8.04	8.52

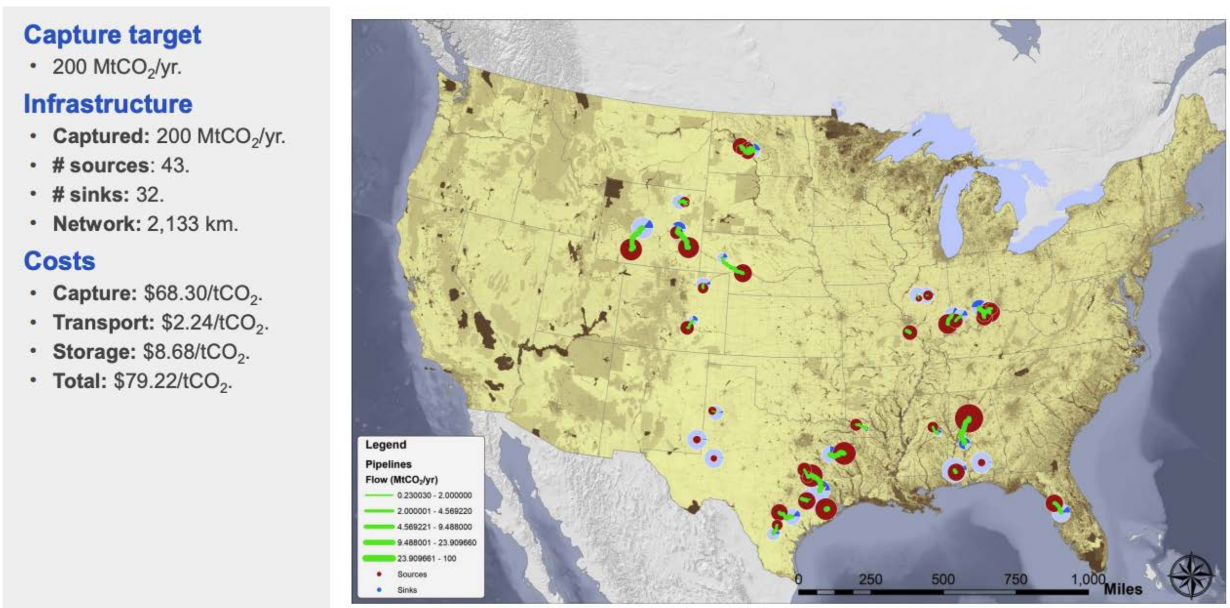

Figure 11. Infrastructure and costs with a capture target of 200 $MtCO_2$/yr, from Carbon Solutions study

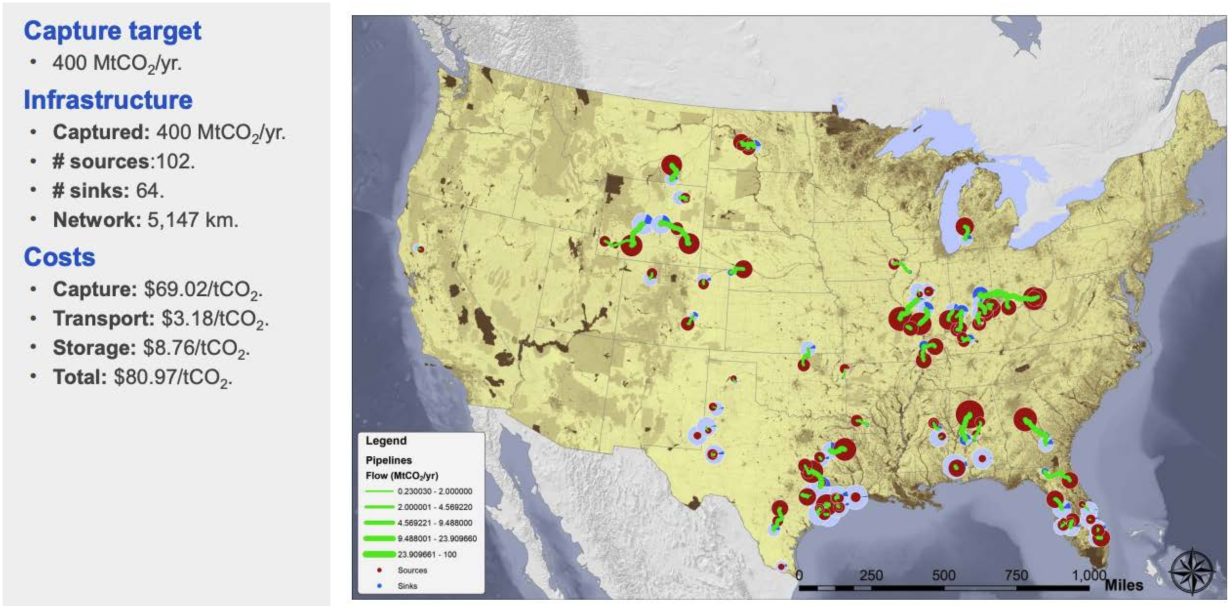

Figure 12. Infrastructure and costs with a capture target of 400 $MtCO_2$/yr, from Carbon Solutions study.

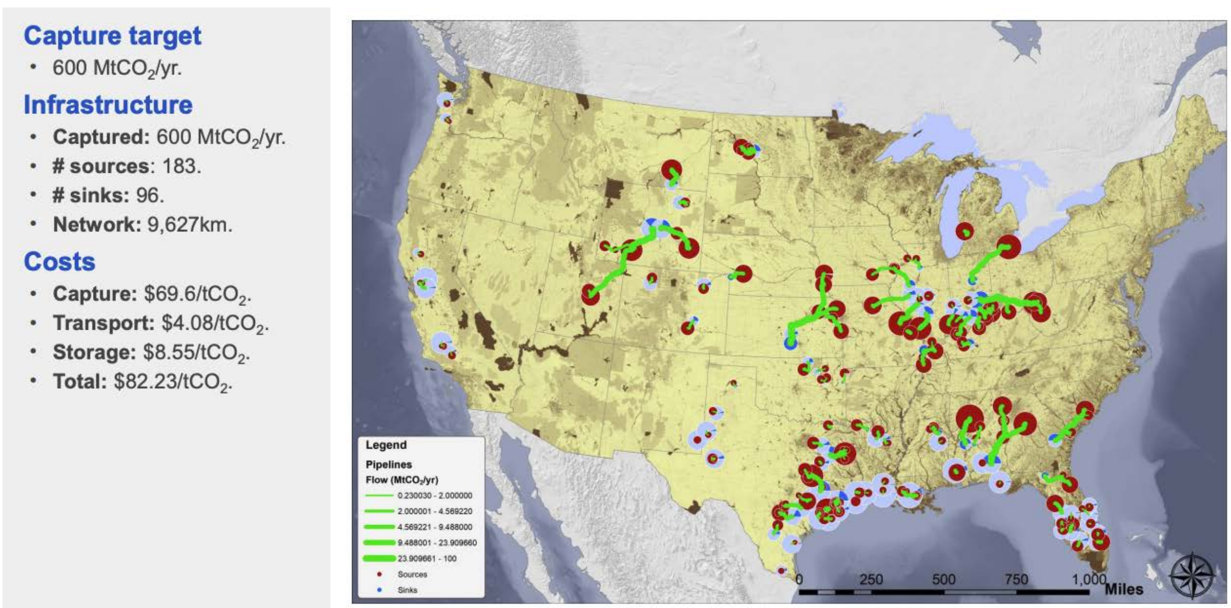

Figure 13. Infrastructure and costs with a capture target of 600 $MtCO_2$/yr, from Carbon Solutions study.

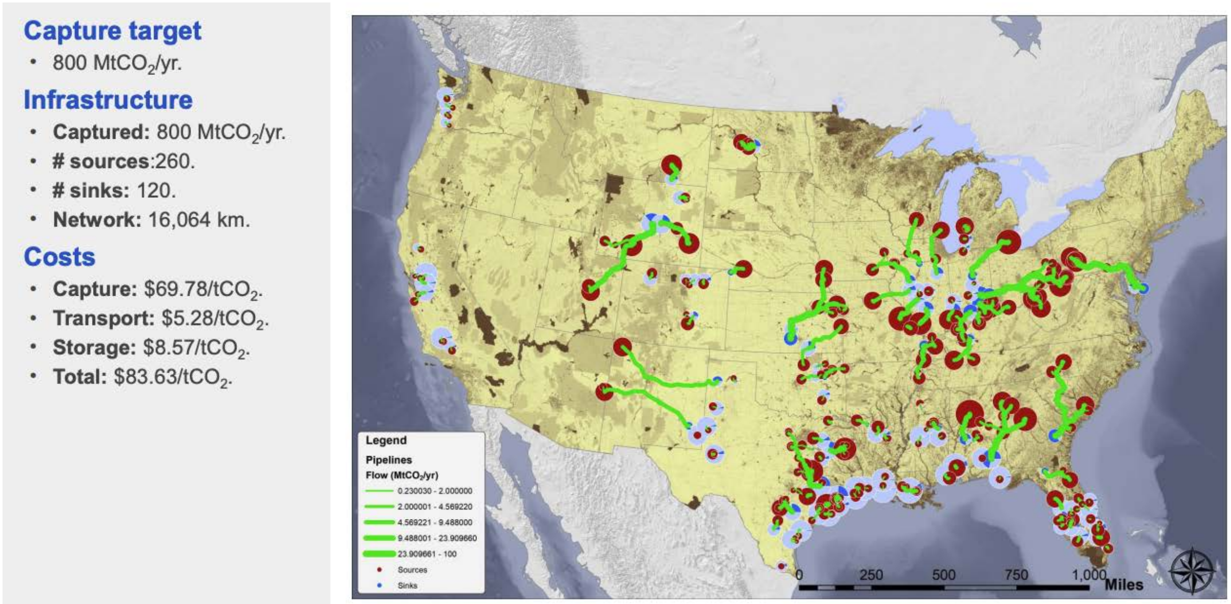

Figure 14. Infrastructure and costs with a capture target of 800 $MtCO_2$/yr, from Carbon Solutions study

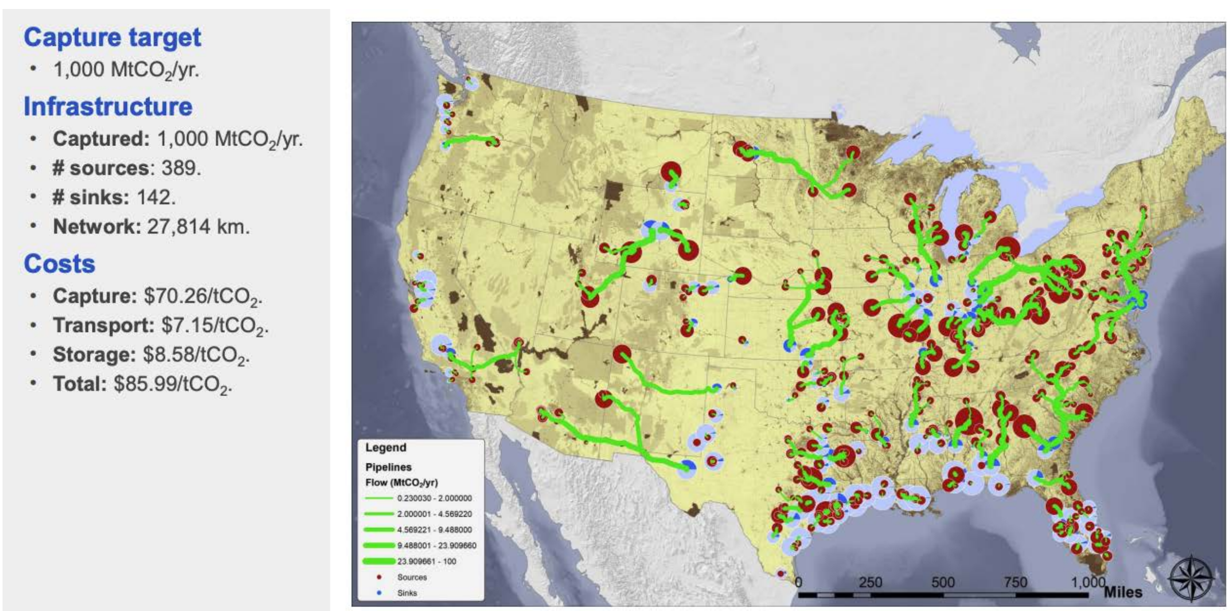

Figure 15. Infrastructure and costs with a capture target of 1,000 $MtCO_2$/yr, from Carbon Solutions study.

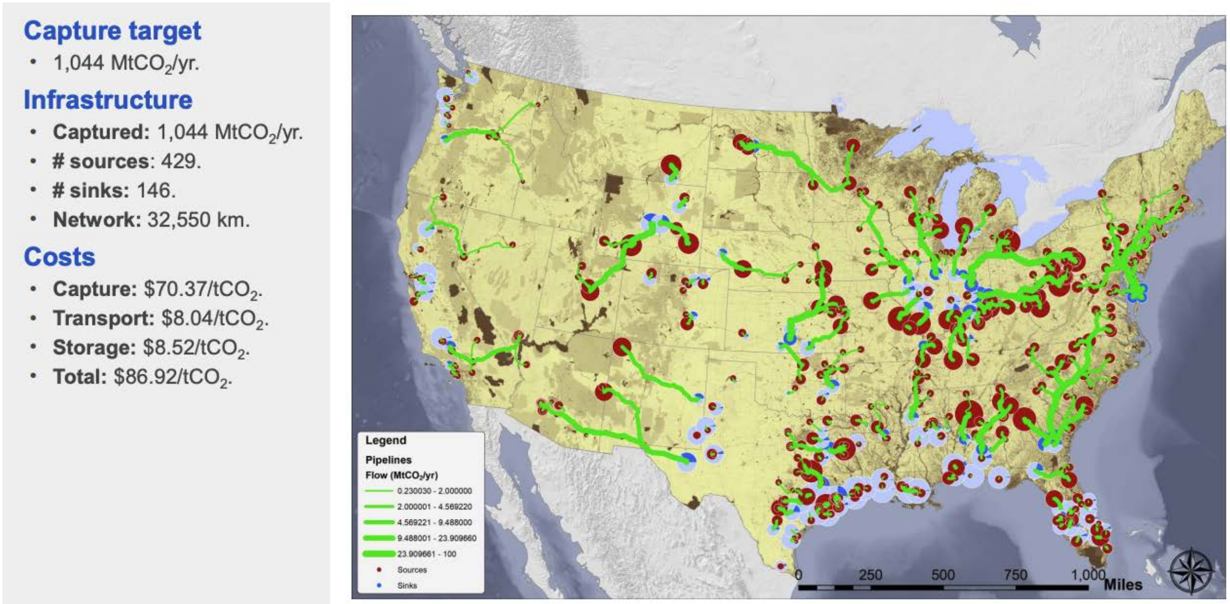

Figure 16. Infrastructure and costs with a capture target of 1,044 MtCO2/yr, from Carbon Solutions study

In addition to these modeled buildout scenarios that cover the bulk of the existing coal and natural gas-fired power plant fleet that does not have an announced retirement date prior to 2030, Commenters requested Carbon Solutions, LLC to perform an additional sensitivity model run that more accurately reflects plants that were covered in this proposed version of the Carbon Pollution Standards. Attachment N. Below are the updated parameters considered for this model scenario:

- NGCC's: plants operating at or above 600 MW
- Coal: plants not set to retire by 2038
- Total # of plants: 198
- Annual CO_2 stored: 618 Mt

CCS buildout costs for this run totaled $87.36 per ton (averaged), which included 198 plants. Average costs by segment of value chain; capture ($69.93/ton), transport ($8.80/ton), storage ($8.63/ton). Total pipeline network length was 19,334 km, which is notably—41 percent—shorter than the previous scenarios that considered a larger number of plants (32,550 km). It is important to note that for this modeled scenario, we assume that every plant considered in this scenario chooses to comply with the standard by applying CCS and the results suggest that CCS buildout for all of these plants is still cost reasonable (average cost of $87.36/ton) when considering the IRS Section 45Q tax credit value of $85/ton.[143]

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[143] Carbon Solutions, LLC, *Affected Fleet Sensitivity* (2023) [Attachment P].

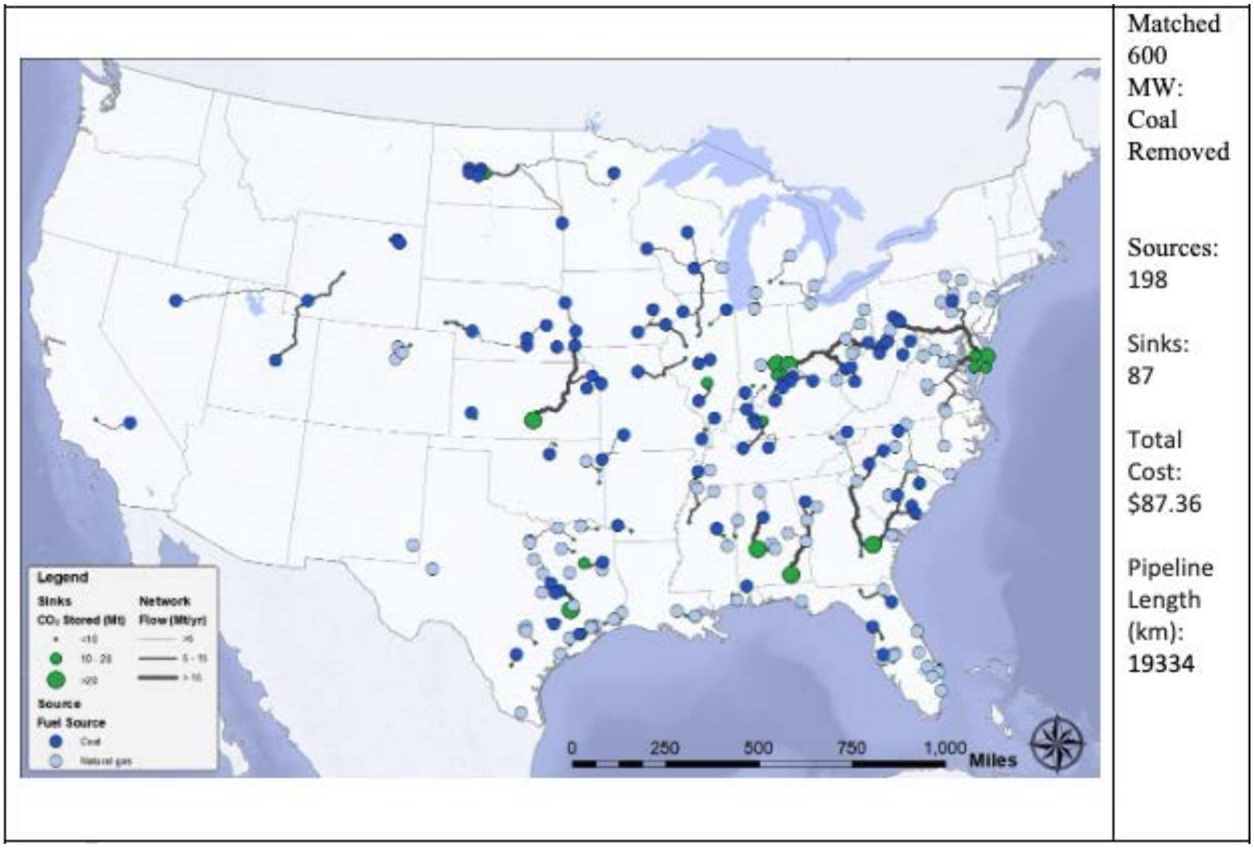

Figure 17. Infrastructure and costs associated with CCS at covered coal-fired and gas-fired power plants

E. Safety

1. Geologic Storage Is Governed by a Robust Existing Regulatory Framework

There is a robust existing regulatory framework that enables safe deployment of CCS. Geologic storage is regulated by the EPA under the Underground Injection Control Program (UIC) of the Safe Drinking Water Act. EPA's UIC program regulates construction, operation, permitting, and closure of injection wells that are used to store fluids in the subsurface. The principal goal of the UIC program is to protect underground sources of drinking water (USDWs) and the program currently permits six classes of injection wells.

EPA's UIC program establishes several classes of injection wells, each subject to different standards. Permanent storage of carbon dioxide is regulated under the Class VI wells program. Class VI wells have extensive requirements to ensure that geologic storage of CO_2 is safe and secure. The Class VI well process starts with stringent permitting requirements designed for ensuring the safety and permanence of CO_2 injection. These permitting requirements ensure that Class VI wells used for storage of CO_2 are appropriately sited, constructed, tested, monitored, and funded.[144] Class VI requirements also ensure that storage sites are appropriately characterized and that once operations have ceased, that wells are properly closed. Below is a more detailed breakdown of the specific criteria for Class VI wells:

- Extensive site characterization requirements, including reservoir modeling that accounts for the physical and chemical properties of the injected CO_2 and identification of a confining zone, or "caprock," directly above the injection zone that acts as a barrier to upward fluid movement.[145]
- Injection well construction requirements for the use of materials that are compatible with and can withstand contact with carbon dioxide and subsurface conditions over the life of a geologic storage project.[146]
- Injection well operational requirements, including injection pressure limitations and use of down-hole shut-off systems to ensure that injection of CO_2 does not endanger underground sources of drinking water.[147]
- Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during injection operations and throughout the 50-year default post-injection site care period. This period can be shortened if operators demonstrate that there is substantial evidence, based on site-specific data, that the geologic storage project does not pose a risk of endangerment to USDWs.[148]
- Financial responsibility requirements assuring the availability of funds for the life of a geologic storage project sufficient to cover the cost of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response.[149]
- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection.[150]

Under EPA's UIC Class VI program, developers that have received a Class VI permit are required to report under subpart RR of the Greenhouse Gas Reporting Program (GHGRP).[151] The two programs work together to ensure secure, permanent storage of CO_2 and provide monitoring

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[144] *See* 40 C.F.R. §§ 146.81-.95.

[145] *See id.* § 146.83.

[146] *See id.* § 146.86.

[147] *See id.* § 146.88.

[148] *See id.* § 146.90.

[149] *See id.* § 146.85.

[150] *See id.* § 146.91.

[151] *See id.* §§ 98.440-.449.

and reporting that identifies and addresses any potential leakage risks and provides public transparency. Class VI permit holders are required to submit annual reports to EPA under subpart RR that include amounts of carbon dioxide that is geologically stored based on mass-balance calculations and monitoring activities.[152] Under subpart RR, facilities are required to develop and implement a monitoring, reporting, and verification (MRV) plan that is approved by EPA.[153] An overview of the required contents of an MRV plan is provided below:

- Delineation of the maximum monitoring area and the Area of Review (AoR) which is the are where pressure perturbations from the injected carbon dioxide are great enough to potentially displace fluids into lowermost USDWs through any potential leakage pathways (e.g., existing wellbores);
- Identification of potential leakage pathways within the AoR (wells, faults, fractures, and caprock competency);
- A detailed strategy for detecting potential leakage of injected carbon dioxide;
- A detailed strategy for establishing a baseline of pre-injection conditions for monitoring of injected carbon dioxide;
- Description of site-specific variables for calculating mass-balance of injected carbon dioxide;
- Well information, including identification numbers; and
- Proposed date to commence data collection for calculating stored carbon dioxide.

The Class VI regulation provides an important, robust environmental backstop that ensures all geologic storage projects are conducted safely and securely.

2. Precedents for Safety of Geologic Storage

Geologic storage carries minimal risk of leakage in well-characterized and well-maintained storage sites. Subsurface geologic formations are capable of retaining fluids, for instance (e.g., hydrocarbons and even naturally occurring CO_2), in the subsurface over geologic time (i.e., up to hundreds of millions of years). The existence of oil and natural gas reserves and naturally occurring CO_2 accumulations in the subsurface demonstrate this ability. According to the IPCC, well-selected geologic storage sites will likely exceed 99 percent retention of injected CO_2 over

[152] *See id.* § 98.446.

[153] *See id.* § 98.448.

1,000 years with "high confidence" that CO_2 can be permanently isolated from the atmosphere.[154]

Carbon dioxide has been injected and stored in deep geologic formations at the commercial scale since the 1970s, with an excellent track record of safety. During this time, over 1 billion tons of CO_2 have been injected into deep geologic formations in the United States alone. The majority of CO_2 injected to date has been via EPA Class II injection wells for the purpose of enhanced oil recovery. The Gulf Coast Carbon Center conducted a major research project in the Scurry Area Canyon Reef Operators (SACROC) oilfield in the Permian Basin focusing on the potential impacts of CO_2 EOR on shallow subsurface aquifers. While the SACROC oil field has seen over 175 million tons of CO_2 injected since 1972, the study found that shallow drinking water aquifers located in geologic layers above the SACROC oil field have not been impacted by injection of CO_2 into these deeper formations.[155] Importantly, Class II injection wells have markedly fewer requirements than Class VI injection wells for ensuring safety and security of injected CO_2. The safe track record of CO_2 injection via Class II wells provides assurance that future injection operations can also be carried out without harm to underground drinking water supplies, much less harm to public health. In fact, Class VI wells are anticipated to carry even less risk than Class II wells due to the additional protections required of Class VI wells (e.g., more extensive site characterization requirements, injection well construction and operating requirements, area of review delineation and plume modeling requirements, extensive monitoring requirements, etc.).

F. Concerns About Permitting Delays

In October 2022 EPA submitted a report to Congress on Class VI permitting.[156] A robust and comprehensive permit application and review process is fundamental, but EPA agreed that the process can be streamlined and that it needs to speed up the process. As described below, EPA has recently, however, demonstrated its ability to permit Class VI wells in a reasonable timeframe by issuing its intent to permit two Class VI wells for Wabash Carbon Services, and expects to be able to maintain its anticipated two-year review timeline.

The 2018 and 2022 passage of enhancements to IRC Section 45Q tax credit, along with investments related to CCS development and deployment, have spurred significant commercial interest in CCS projects. In addition, recent legislation has increased the 45Q credit value for

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[154] IPCC, *Carbon Dioxide Capture and Storage* 14 (2005) (special report prepared by IPCC Working Group III), https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf; IPCC, *Climate Change 2022: Mitigation of Climate Change Summary for Policymakers*, https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SummaryForPolicymakers.pdf.

[155] *See generally* Gulf Coast Carbon Ctr., *SACROC Research Project*, https://www.beg.utexas.edu/gccc/research/sacroc.

[156] EPA, *EPA Report to Congress: Class VI Permitting* (2022), https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf.

captured CO_2 when utilized for, e.g., enhanced oil recovery, which may spur additional voluntary investment.[157]

The first Class VI permits took approximately 6 years to be issued, and EPA did not issue any such permits from 2015–2023. But since this period, EPA anticipates that prospective owners or operators submitting complete Class VI applications will be issued permits in approximately two years,[158] and recent timelines appear to be even faster. In 2024, two permits were issued for the Wabash Carbon Services project in Indiana in January 2024,[159] followed by four permits in California issued in December 2024,[160] and an additional three Texas wells permits issued in April 2025.[161] EPA's most recent draft permit issuance for ExxonMobil's Rose Carbon Capture and Storage Project in Region 6 took 16 months from application submission to draft permit issuance, approximately 12 months faster than the previous permit issuance in Region 6 for Oxy's Brown Pelican Project and 5 months faster than EPA's own guidance of 21 months.[162] This demonstrates EPA's ability to expeditiously permit Class VI wells.

Interest in Class VI wells remains strong. According to EPA's real-time Class VI permit tracking dashboard, there are currently 191 Class VI well applications under review across 63 different projects pending review.[163]

In its 2022 report to Congress on Class VI permitting, EPA indicated that, while there is limited data on Class VI permitting timeframes, processing times for other UIC well classes offer a valid metric of comparison. For example, Class I wells are similar to Class VI in terms of regulatory structure, including the amount of site-specific data that is required as part of the permit application. EPA states that the processing time for Class I permits has typically been less than two years, and since 2019, EPA has issued 25 new Class I permits. This provides precedent that EPA has the ability to permit Class VI wells in a timely manner (i.e., approximately two years).

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[157] One Big Beautiful Bill Act, Pub. L. No. 119-21, § 70522 (2025) (codified at 26 U.S.C. § 45Q).

[158] EPA, *EPA Report to Congress: Class VI Permitting* (2022), https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf.

[159] EPA, *Public Notice: EPA Approves Permits for Wabash Carbon Services Underground Injection Wells in Indiana's Vigo and Vermillion Counties* (Jan. 24, 2024), https://www.epa.gov/uic/epa-approves-permits-wabash-carbon-services-underground-injection-wells-indianas-vigo-and.

[160] Global CCS Institute, *California's First Class VI Well Permits Approved by U.S. EPA* (Jan. 10, 2025), https://www.globalccsinstitute.com/news-media/latest-news/californias-first-class-vi-well-permits-approved-by-u-s-epa/; EPA, *EPA issues first ever underground injection permits for carbon sequestration in California* (Dec. 31, 2024), https://www.epa.gov/newsreleases/epa-issues-first-ever-underground-injection-permits-carbon-sequestration-california.

[161] EPA, *EPA Issues Final Permits for Geologic Sequestration of Carbon Dioxide in Texas* (Apr. 7, 2025), https://www.epa.gov/newsreleases/epa-issues-final-permits-geologic-sequestration-carbon-dioxide-texas.

[162] Data derived from EPA UIC Class VI Permit Tracker Dashboard, https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.

[163] EPA, UIC Class VI Permit Tracker Dashboard (last updated July 3, 2025), *available at* https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.

EPA has a suite of tools and strategies for permitting Class VI wells. It includes early engagement; improvements to its geologic sequestration data tool in order to streamline the application process; templates; samples; application guidance; training for regulators; mapping tools; and tools for UIC permit writers to standardize and expedite the process. NETL also has a data portal that provides information needed to accelerate the process of completing a Class VI permit.[164] Operators can use the database to query and download relevant spatial data for the entire U.S. and visualize subsurface data. These tools will help both prospective applicants and EPA to accelerate permitting timelines. EPA is also encouraging and supporting states with applying for Class VI primacy.

Additional funding support for EPA Class VI permitting is included in the Bipartisan Infrastructure Law, totaling $25 million between FY22 and FY26 to specifically address challenges around permitting timelines and ensure that EPA has the appropriate resources to keep up with the growing influx of Class VI permit applications. An additional $1.93 million has been allocated across 23 states and 2 tribes to support primacy to administer EPA's UIC program.[165] Currently, North Dakota, Wyoming, Louisiana, and West Virginia have state primacy for Class VI well permitting with Louisiana and West Virginia obtaining EPA approval in 2024 and 2025, respectively.[166] Nine other states are currently in the process of applying for Class VI primacy (Alabama, Alaska, Colorado, Mississippi, Nebraska, Oklahoma, and Utah),[167] and EPA has proposed to approve the applications for Texas and Arizona.[168]

There were two saline storage projects in operation (i.e., injecting CO_2) and 142 EOR projects injecting CO_2 as of year-end 2020 in the U.S. Following the 2018 enhancements to IRC Section 45Q tax credit, there was a significant surge in commercial interest in CCS with over 100 commercial projects announced since 2018.[169] Of these announced projects, there are numerous large-scale storage projects underway that have significant storage capacities and are intended to be used as storage hubs for a variety of industries.

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[164] Carbon Capture Journal, *NETL data portal to aid completion of permit applications for carbon storage* (Apr. 13, 2023), https://www.carboncapturejournal.com/news/netl-data-portal-to-aid-completion-of-permit-applications-for-carbon-storage/5504.aspx?Category=all.

[165] EPA, *Underground Injection Control Class VI Wells Grant Program, Grant Implementation Document* at 11-12 (effective May 2025), https://www.epa.gov/system/files/documents/2025-05/uic-class-vi-primacy-grant-implementation-document_5-7-25.pdf.

[166] 89 Fed. Reg. 703 (Jan. 5, 2024) (Louisiana); 90 Fed. Reg. 10691 (Feb. 26, 2025) (West Virginia).

[167] Samuel Pickerill et al., *Class VI Primacy Update*, Arnold & Porter (May 30, 2025), https://www.arnoldporter.com/en/perspectives/blogs/environmental-edge/2025/05/class-vi-primacy-update.

[168] 90 Fed. Reg. 25547 (June 17, 2025) (Texas); 90 Fed. Reg. 21264 (May 19, 2025) (Arizona).

[169] CATF, *US Carbon Capture Activity and Project Map*, https://www.catf.us/ccsmapus/ (last visited Aug. 6, 2025).

III. Pipelines

CO_2 pipelines are an essential transport component of the CCS capture, transport, and storage value chain. In comparison to the 2 million mile U.S. oil and gas pipeline network,[170] there are currently 5,000 miles of pipelines carrying CO_2, primarily from natural CO_2 sources to oil fields where the CO_2 is used for enhanced oil recovery.[171] While the U.S. has a strong track record for operating CO_2 pipelines for the past 50 years, there are considerations that must be taken into account, including permitting concerns, cost of transport, and safety standards.

From 2001 to 2021, the fastest pace of pipeline expansion in the U.S. took place from 2001 to 2006 where the total U.S. oil and gas pipeline mileage increased from 1.57 million miles to 1.68 million miles (an average of nearly 21,000 miles per year). Gas transmission pipeline mileage increased from 289,994 miles to 300,324 miles during the same time period (an average of just over 2,000 miles per year).[172] In comparison, the mileage of CO_2 pipelines required to comply with the Carbon Pollution Standards is likely to be far smaller than these historic annual pipeline construction rates. The Carbon Solutions Report described earlier showed a total maximum CO_2 pipeline need of 12,013 miles to capture all of the CO_2 from the portion of the fleet Commenters proposed subjecting to a CCS-based standard. This maximum buildout scenario represents just over half of the average buildout associated with *one year* during the natural gas boom. Studies suggest that the U.S. will need 30,000 to 66,000 miles of CO_2 pipelines by 2050 in order to meet net-zero targets.[173] Even this economy-wide decarbonization goal only requires an average of 2,444 miles annually from 2023.

The IRA and IIJA include provisions that support CO_2 pipeline development, including a Carbon Dioxide Transportation Infrastructure Finance and Innovation Program (CIFIA) for CO_2 pipelines. This IIJA (Section 40304) program provides $2.1 billion for low-interest loans and grants for CO_2 transportation, including pipelines.[174] Section 40303 of the IIJA also gives DOE the authority to include support for CO_2 transport infrastructure FEED studies, and in May 2023, DOE announced $9 million in funding for three CO_2 pipeline network FEED studies in

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[170] *See U.S. Oil and Gas Pipeline Mileage*, Bureau Transp. Stat. (BTS), https://www.bts.gov/content/us-oil-and-gas-pipeline-mileage (last visited Aug. 6, 2025).

[171] Cong. Rsch. Serv. (CRS), *Carbon Dioxide (CO_2) Pipeline Development: Federal Initiatives* (2023) [hereinafter CRS, *CO_2 Pipeline Development*], https://crsreports.congress.gov/product/pdf/IN/IN12169#:~:text=Approximately%205%2C000%20miles%20of%20pipeline,goals%20for%20greenhouse%20gas%20reduction.

[172] *See U.S. Oil and Gas Pipeline Mileage*, Bureau Transp. Stat. (BTS), https://www.bts.gov/content/us-oil-and-gas-pipeline-mileage (last visited Aug. 6, 2025).

[173] Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts* (2021), https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf; Elizabeth Abramson et al., *Transport Infrastructure for Carbon Capture and Storage*, Great Plains Institute (June 2020), https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf.

[174] Congressional Research Service, *Carbon Dioxide (CO2) Pipeline Development: Federal Initiatives* (2023), https://crsreports.congress.gov/product/pdf/IN/IN12169.

Wyoming, Louisiana, and Texas.[175] The IIJA (Section 40314) also established the Regional Clean Hydrogen Hubs program, which will provide funding to support six to 10 hubs. It is anticipated that several of these hubs will include CCS, and may require pipeline infrastructure.

Developers such as Summit Carbon Solutions are requesting permits to develop CO_2 pipeline transport networks in the upper Midwest, and have begun engaging stakeholders. Summit has received approvals from Iowa's Utilities Commission and North Dakota's Public Service Commission for their project.[176] Meanwhile, Wood is delivering concept and FEED studies for nearly 2,000 miles of onshore low-carbon pipelines in North America.[177]

IV. Costs of Carbon Capture and Sequestration

The costs of CCS on power plants depend upon many factors, including the concentration of CO_2 in the flue gas, other pollutants that must be treated to protect the amine used to capture CO_2, capacity factor, plant size, the amortization period, retrofit costs as opposed to including CCS as part of a new plant, and the availability of tax credits or other policies to offset costs. This section sets forth detail on the costs of CCS depending on those variables.

NETL has developed detailed and transparent costs for CCS on power plants, including recent updates to fossil baseline reports and retrofit studies that include the latest vendor quotes for carbon capture and other updated data. The Carbon Pollution Standards properly relied on such reports to develop the cost and performance basis of the proposal. These reports include:

New Coal and New Gas with CCS

- Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity[178]

Coal Retrofits with CCS

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[175] *Id.*

[176] Jeff Beach, *North Dakota approves Summit carbon pipeline route* (Nov. 15, 2024) https://northdakotamonitor.com/2024/11/15/north-dakota-approves-summit-carbon-pipeline-route/ (North Dakota); Iowa Utlities Commission, *Summit Carbon Solutions and SCS Carbon Transport: Applications to Construct Hazardous Liquid Pipelines* (June 19, 2025), https://iuc.iowa.gov/hazardous-liquid-pipeline-requests (Iowa).

[177] Wood Group PLC, Press Release, *Wood Delivers 2,000 miles of low carbon pipeline projects in North America* (Aug. 3, 2023) https://www.woodplc.com/news/latest-press-releases/2023/wood-delivers-2000-miles-of-low-carbon-pipeline-projects-in-north-america.

[178] NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (Oct. 19, 2022), https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf (update for new plants that came out on Oct. 19, 2022).

- Eliminating the Derate of Carbon Capture Retrofits (Revision 2)[179]
- Pulverized Coal Carbon Capture Retrofit Database[180]

Natural Gas Retrofits with CCS

- Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3)[181]
- Natural Gas Combined Cycle CO_2 Capture Retrofit Database[182]

A. Costs of Carbon Capture for Gas-Fired Versus Coal-Fired Power Plants

Two attributes highlighted here strongly influence the cost difference between coal and gas plants CCS applications: (1) CO_2 concentrations in flue gas and (2) pretreatment costs to prepare flue gas for entry into the capture system.

Flue gas concentrations of CO_2 in NGCC plants are about 3 percent compared to 12 percent for coal plants. This difference accounts for much of the cost difference between CCS applications on the two plants. Also, coal plant applications of CCS require more pretreatment steps for the flue gas to ensure that harmful pollutants such as PM, sulfates, and NO_2 do not form heat-stable salts with the amine or contribute to other degradation products that harm the capture system.

Because there is less CO_2 emitted per MWh from a gas plant relative to a coal plant, the cost of CCS on a gas plant is lower than a coal plant on an LCOE basis measured in $/MWh. However, the situation is reversed when measuring costs based on $/ton of CO_2 avoided. The cost per ton of CO_2 avoided with CCS on coal plants is less than on gas plants because the costs are spread over a larger quantity of CO_2 captured. The table below summarizes NETL findings from new coal and gas plants with 90 percent capture.[183]

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[179] NETL, *Eliminating the Derate of Carbon Capture Retrofits* (Mar. 31, 2023), https://www.osti.gov/biblio/1968037.

[180] NETL, *Pulverized Coal CO_2 Capture Retrofit Database* (Mar. 30, 2023) (spreadsheet allows users to apply the findings from the report above to a fleet of plants), https://www.netl.doe.gov/energy-analysis/details?id=e7e822ff-18ac-4bc6-a052-0be3521b8789.

[181] NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3)* (May 31, 2023), https://www.netl.doe.gov/energy-analysis/details?id=addea891-b037-4559-9f37-a2294e131ab6 (This reports adapts the October 22 report on new gas plant CCS costs to account for the additional costs of retrofits.).

[182] NETL, *Natural Gas Combined Cycle CO_2 Capture Retrofit Database* (Mar. 16, 2023) (This spreadsheet adapts the report above to apply the findings to a fleet of gas plants), https://www.osti.gov/biblio/1962372.

[183] NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (Oct. 19, 2022), https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.

Table 6. LCOE and Cost of CO_2 Avoided for Coal and Gas EGUs.[184]

	LCOE ($/MWh) (incl. T&S)	Cost of CO2 Avoided (incl. T&S), $/ton
Supercritical pulverized coal at 90% capture (SC PC: B12B.90 (12)	107.3	63.0
State-of-the-art 2017 F-Class combustion turbine NGCC at 90% capture (B31B.90 (14)	67.9	80.8

Assumes 30-year payback period.

While 90 percent capture is often described in studies, as described above, there is no technical barrier to achieving higher capture rates. Figure 18 summarizes NETL estimates for LCOE for retrofitting subcritical coal plants, new NGCC-CCS plants, and CCS retrofits on NGCC plants.[185] The cost of capture for coal plant retrofits ranges between around $86/MWh to $92/MWh. For new NGCC plants with CCS and retrofits of existing gas plants, the LCOE ranges between $59/MWh and $66/MWh.

[184] NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (Oct. 19, 2022), https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.

[185] *See* NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3),* at 5 (May 31, 2023), https://www.netl.doe.gov/energy-analysis/details?id=addea891-b037-4559-9f37-a2294e131ab6 (gas); NETL, *Eliminating the Derate of Carbon Capture Retrofits* (Mar. 31, 2023), https://www.osti.gov/biblio/1968037 (coal).

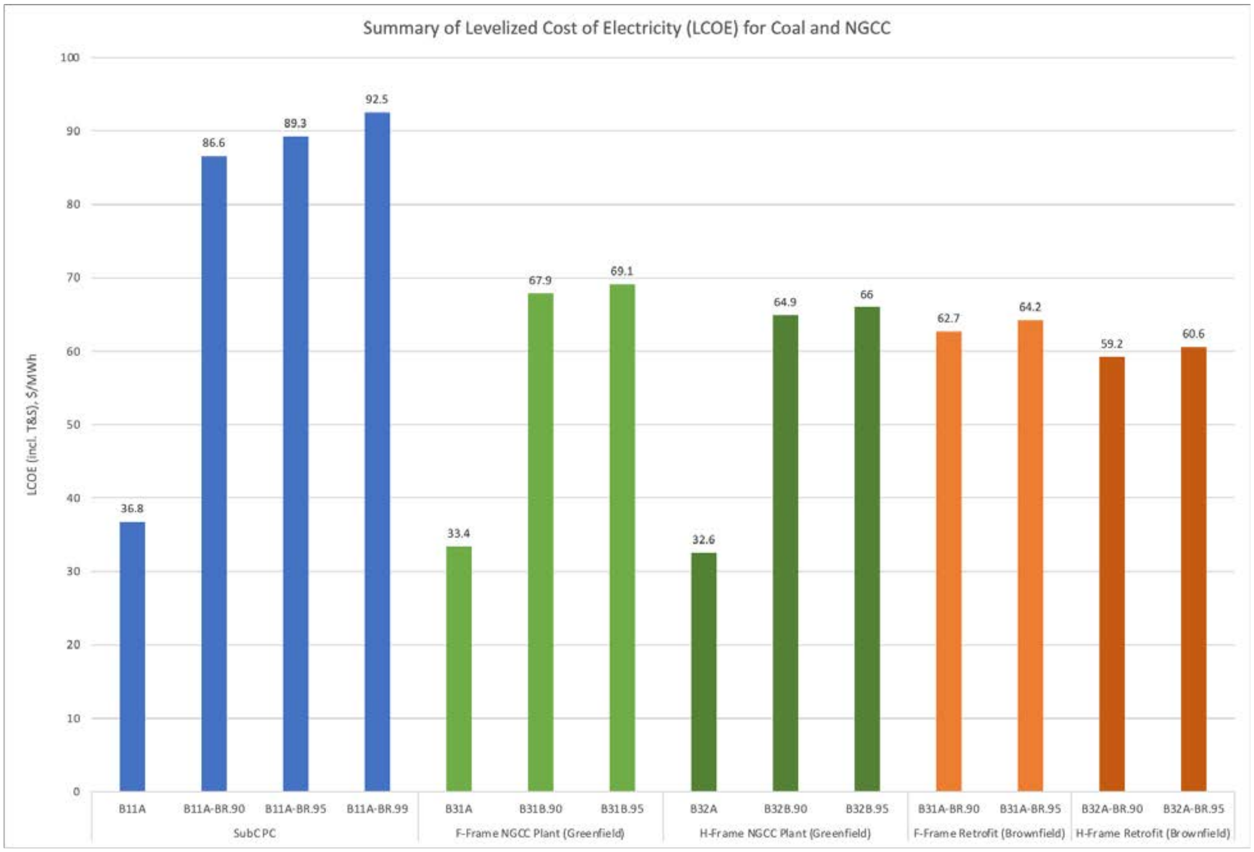

Figure 18. LCOE of CCS on new and retrofitted coal-fired and gas-fired power plants.[186]

Note that, in this figure:

- In order to account for the higher costs of a retrofit CCS application compared to the cost of including CCS as part of a new build, NETL applies a retrofit difficulty factor to the capital costs of CCS retrofits by multiplying the capital costs of an equivalent greenfield site by 1.09.
- The uncontrolled coal and gas plants are assumed to be fully paid off and LCOE excludes capital costs.
- LCOE is calculated on a 30-year plant life.

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[186] *Id.*

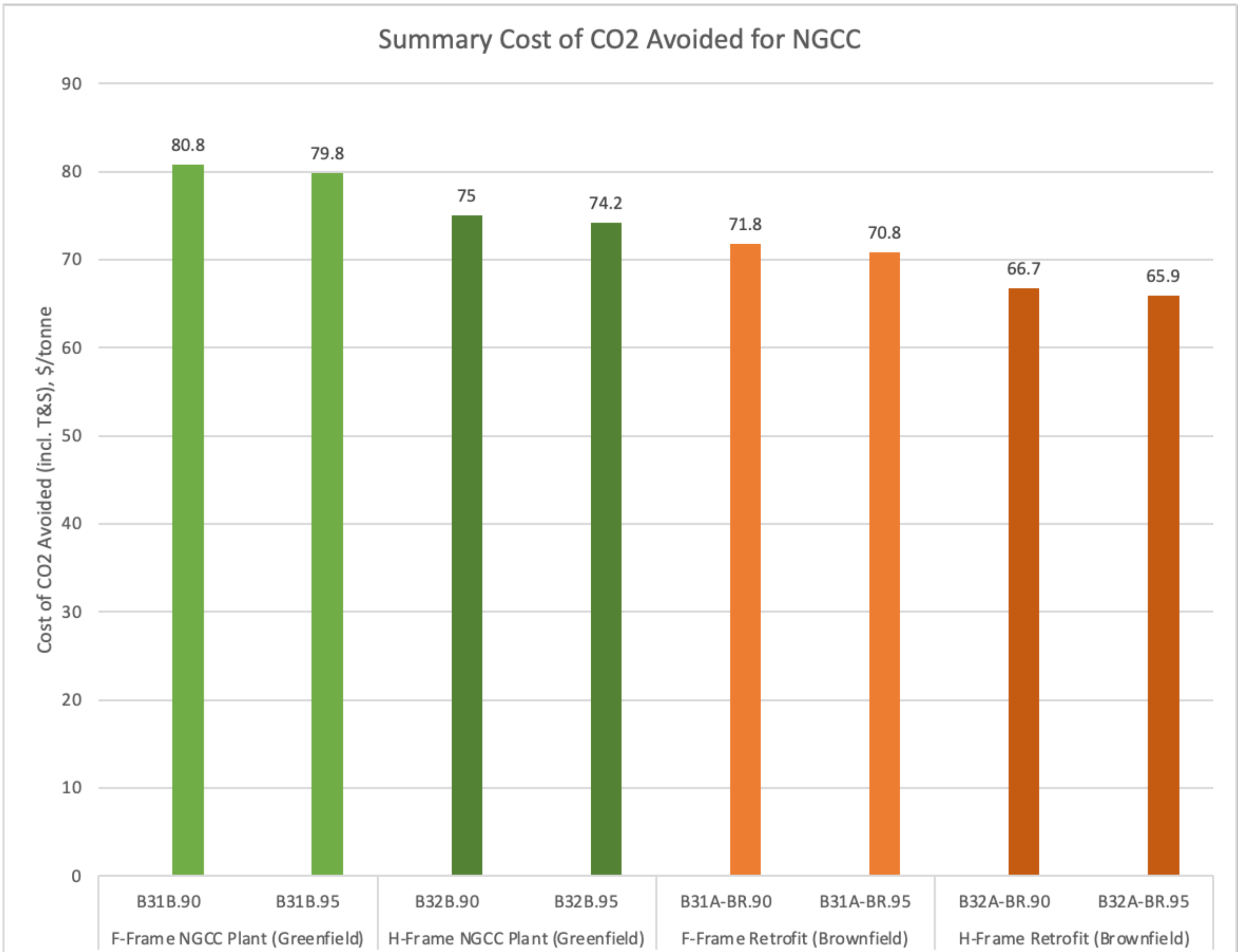
Table 7. NETL Case Specifications[187]

Case	Technology		Efficiency (% HHV)	2xGT (MWe)	ST (MWe)[A]	Gross (MWe)	Aux (MWe)	Net (MWe)
1 Subcritical Pulverized Coal	B11A	w/o CO_2 capture	38.6	N/A	N/A	688	38	650
	B11A-BR.90	w/90% CO_2 capture retrofit	29.4	N/A	N/A	588	93	495
	B11A-BR.95	w/95% CO_2 capture retrofit	28.9	N/A	N/A	584	96	488
	B11A-BR.99	w/99% $C0_2$ capture retrofit	28.4	N/A	N/A	578	99	479
2 SOA Based on F-Frame	B31A	w/o CO_2 capture	53.6	477	263	740	14	727
	B31B.90	w/90% CO_2 capture	47.6	477	215	692	47	645
	B31B.95	w/95% CO_2 capture	47.3	477	212	690	49	640
	B31A-BR.90	w/90% CO_2 capture retrofit	47.3	477	211	688	47	641
	B31A-BR.95	w/95% CO_2 capture retrofit	46.9	477	208	685	49	636
3 SOA Based on H-Frame	B32A	w/o CO_2 capture	55.1	686	324	1,009	17	992
	B32B.90	w/90% CO_2 capture	49.0	686	260	945	62	883
	B32B.95	w/95% CO_2 capture	48.7	686	256	942	65	877
	B32A-BR.90	w/90% CO_2 capture retrofit	48.7	686	255	940	62	878
	B32A-BR.95	w/95% CO_2 capture retrofit	48.4	686	251	936	65	872

NETL cost estimates for the avoided cost of capture for new and retrofit NGCC is shown below assuming a 30-year plant life.

[187] *Id.*

Table 8. Cost of CO_2 avoided for new and retrofitted NGCC plants. [188]



In 2024, NETL completed an updated cost analysis of new and retrofit combined cycle power plants with carbon capture, based on H-class turbines and an 'X-class' turbine case representing combustion technology which could be available for commercial operation in 2035.[189] This study also examines a 97% capture rate case and an advanced carbon capture case with performance parameters based on outcomes from research projects supported by the Office of Fossil Energy and Carbon Management. Compared to the previous NETL baseline study, the analysis indicates a much smaller relative increase in the levelized cost of electricity for CO_2 capture cases, relative to unabated plant (Figure 19). Under baseline carbon capture assumptions, the LCOE of a

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[188] NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3)* (May 31, 2023), https://www.netl.doe.gov/energy-analysis/details?id=addea891-b037-4559-9f37-a2294e131ab6.

[189] Sarah Leptinsky et al., *Cost and performance estimates for state-of-the-art and advanced 1x1 H-class natural gas-fired power plants* (2024), DOE/NETL-2024/4444 [Attachment K].

greenfield H-class plant is 55% greater than the unabated case for 90% capture, or 58% greater for 97% capture. Cost increases for retrofits to H-class plants are still lower, with 90% capture incurring a 31% cost increase and 98% capture a 36% increase.

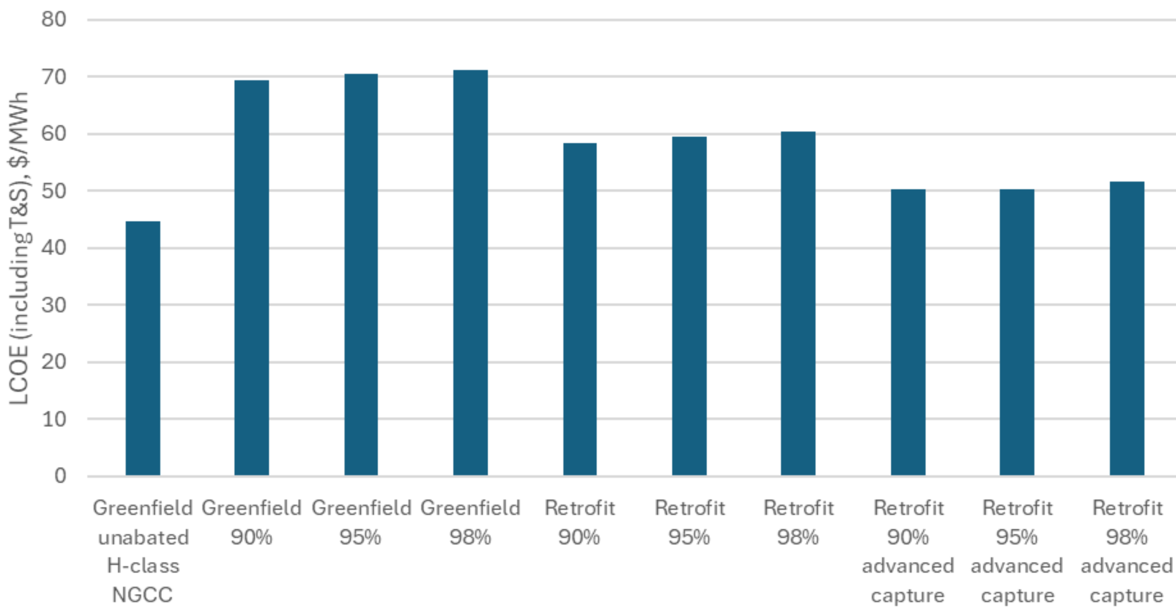

Figure 19. Levelized cost of electricity for state-of-the-art H-class NGCC power plants with 90%, 95%, and 97% CO2 capture using state-of-the-art and advanced capture technology, simplified from Leptinsky et al., fn. 189.

B. Costs Depend on Amortization Time

The costs shown in the previous section assume a 30-year plant life. Shortening the amortization periods increases the cost of capture of a project as shown in Figure 20.[190]

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[190] *See* NETL, *Natural Gas Combined Cycle CO_2 Capture Retrofit Database* (Mar. 16, 2023), https://www.osti.gov/biblio/1962372 (analysis performed using this database, modified to include capital recovery factor based on 12-year period).

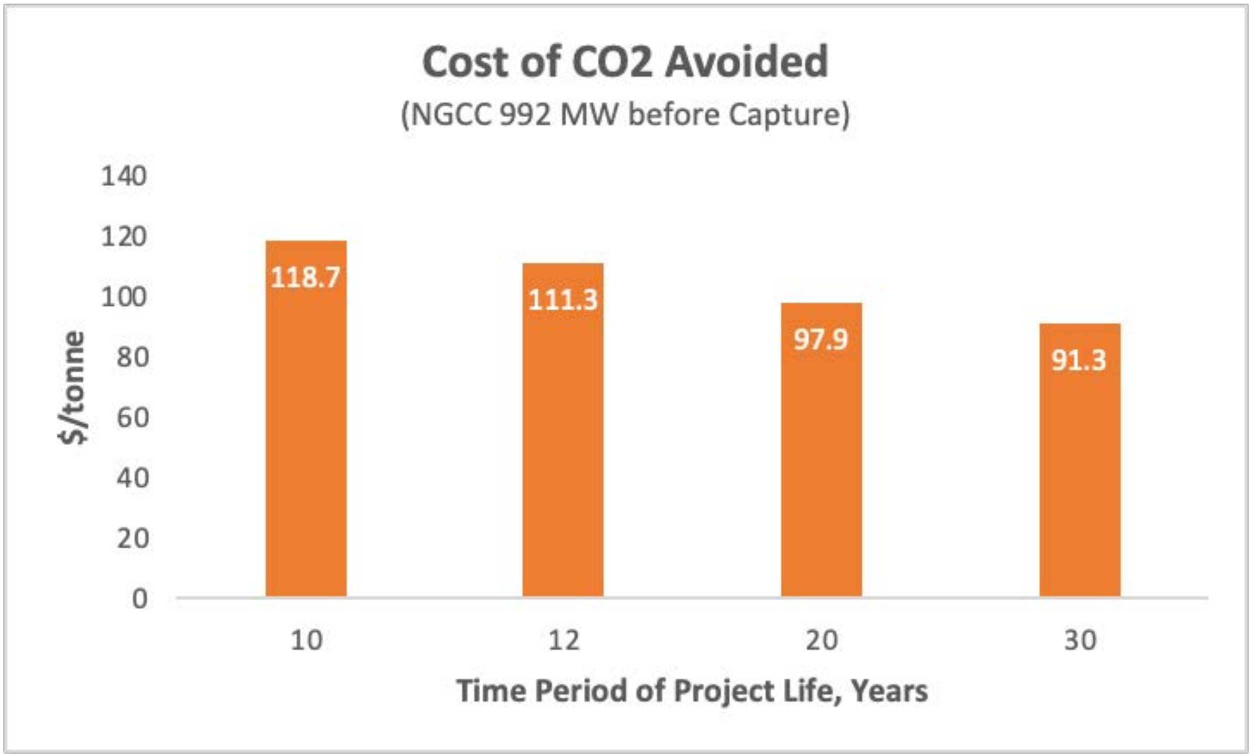

Figure 20. Cost of CO_2 avoided by amortization period for CCS at an NGCC plant.

C. Costs for Gas-Fired Power Plants According to Capacity Factor and Plant Size

EPA's Carbon Pollution Standards reported the following costs for new natural gas plants with CCS:[191]

[191] EPA, *Technical Support Document: GHG Mitigation Measures for Combustion Turbines*, Docket ID No. EPA-HQ-OAR-2023-0072-0057, at 11, fig.7 (2023) [hereinafter *GHG Mitigation Measures for Combustion Turbines TSD*], https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0057.

Table 8. Cost of CCS for New Combustion Turbines[192]

	NETL F-Class, No CCS	NETL F-Class, 90% CCS	NETL H-Class, No CCS	NETL H-Class, 90% CCS
Total As Spent Capital (TASC) ($/kW)	1,060	2,280	1,080	2,150
TASC of Carbon Capture Equipment (million $))		700		830
Base Load Rating (MMBtu/h)	4,623	4,623	6,147	6,147
Net Power Output (MW)	727	645	992	883
Derate from CCS (%)		11%		11%
Gross Efficiency (%)	54.6%	51.1%	56.1%	52.5%
Net Efficiency (%)	53.6%	47.6%	55.1%	49.0%
Increase in Heat Rate from CCS (%)		13%		12%
Design Capture Rate (tonne/h)		225		299
Fixed Costs ($/MWh)	6.1	12.6	6.0	11.6
Fixed Costs of Carbon Capture Equipment (million $)		16		19
Variable Costs ($/MWh)	1.7	4.1	1.7	3.9
Increase in Variable Costs from CCS ($/MWh)		2.4		2.2
Fuel Costs ($/MWh)	23.0	25.9	22.4	25.1
Capital Costs ($/MWh)	19.1	41.2	195	38.9
TS&M Costs ($/MWh)		7.7		6.4
45Q Tax Credit ($/MWh)		12.6		12.2
LCOE ($/MWh)	50	79	50	74
Abatement Costs ($/MWh) (net of 45Q tax credit)		29		24
Abatement Costs ($/tonne) (net of 45Q tax credit)		95		81

* Assumptions: 30-year amortization, 7 percent interest rate, $3.61/MMBtu natural gas, $67/tonne tax credit for 12 years (effective rate amortized over 30 years is $36/tonne), 51 percent average annual capacity factor, and $22/tonne TS&M costs for the F-Class combined cycle turbine and $19/tonne for the H-Class combined cycle turbine (CO_2 transport, storage, and monitor (TS&M) costs are based on the amount of CO_2 captured).

These costs assume a 51 percent capacity factor and account for receiving the $85/ton tax credit. The new uncontrolled F-Class plant shown in the table is 727 MW. If the same plant is built at the outset with 90 percent CCS, the maximum plant output drops to 640 MW. The new uncontrolled H Class NGCC is 992 MW, and building the plant with 90 percent CCS drops the plant output to 883 MW. The larger H-Class plant is more efficient, and this contributes to lower CCS costs.

The plant configurations shown in the table can be adjusted to explore the cost impacts of changing capacity factors. If the capacity factor decreases, the costs of CCS as measured on an LCOE basis increase. If the capacity factor increases, the LCOE falls. Figure 21 shows the impact of changing the capacity factor for the F-Class and H-Class plants with 90 percent capture and without CCS based on Commenters' prior work on the proposed Carbon Pollution

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[192] EPA, Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines, Technical Support Document at 12 (April 2024) (Figure 7),Docket ID No. EPA-HQ-OAR-2023-0072, *available at* https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-9099.

Standards.[193] Note that the costs of the uncontrolled plants are so similar that they overlap such that only the F-Class data is visible.

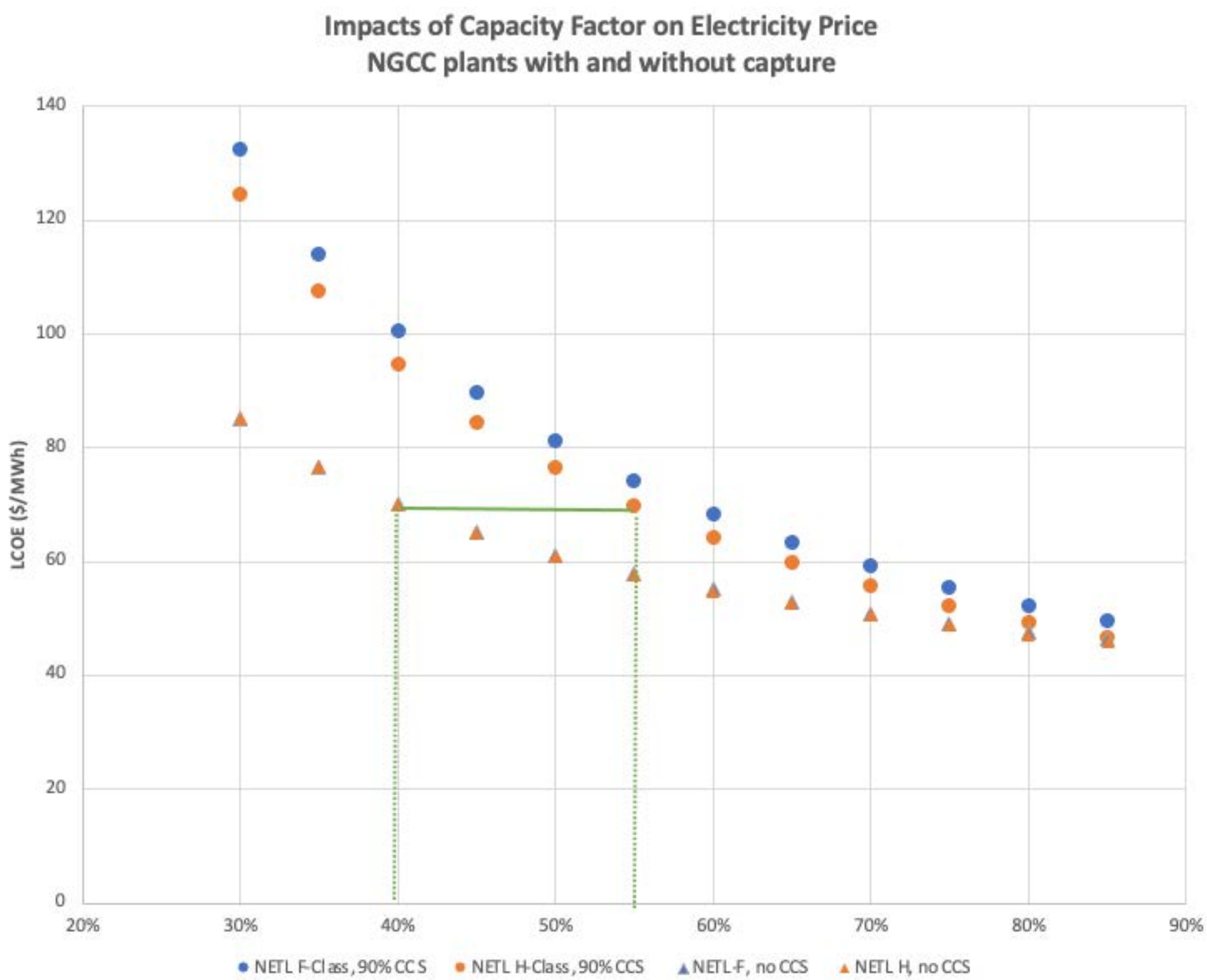

Figure 21. Impacts of capacity factor on LCOE for NGCC plants with and without CCS

The green lines show that at 40 percent capacity factor, a new uncontrolled NGCC plant has an LCOE of around $70/MWh. An equivalent LCOE for an NGCC with CCS would need to run at 55 percent capacity factor. Plants that add CCS and can obtain 45Q tax credits can expect the capacity factor to increase compared to an uncontrolled plant. That is because 45Q effectively offsets some variable costs, enabling the CCS equipped plant to advance in the dispatch order. A 2019 Southern Company paper on the impacts of 45Q notes that the tax credit can act as a

[193] Costs developed using EPA spreadsheet, Docket ID EPA-HQ-OAR-2023-0072-0057 Attachment 1, *available at* https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0057 (CCS Costing for combustion turbines), with the following assumptions: CRF 12 years, natural gas price $3.69/MMBTU, $85/ton 45Q credit, 7 percent interest rate, CO_2 T&S 10$/ton.

"bounty" that lowers variable costs and ultimately moves CCS ahead in the dispatch order.[194] In the stylized illustrative example cited in the article, the old $50/ton 45Q tax credit value moved the NGCC plant with CCS from 2 MM MWh/yr of generation to 3 MM MWh/yr.

D. Anticipated Cost Declines

EPA's cost analysis in the Carbon Pollution Standards was conservative as it was based on current carbon capture vendor estimates and current transportation and storage costs. The Clean Air Act, however, is forward looking and CCS-based standards will not be required until 2032. Significant cost declines are expected in that timeframe making EPA's cost estimates particularly conservative. Figure 22 shows the significant cost declines expected by 2030. The figure shows "first-of-a-kind," or "FOAK," and "nth-of-a-kind," or "NOAK," projects.

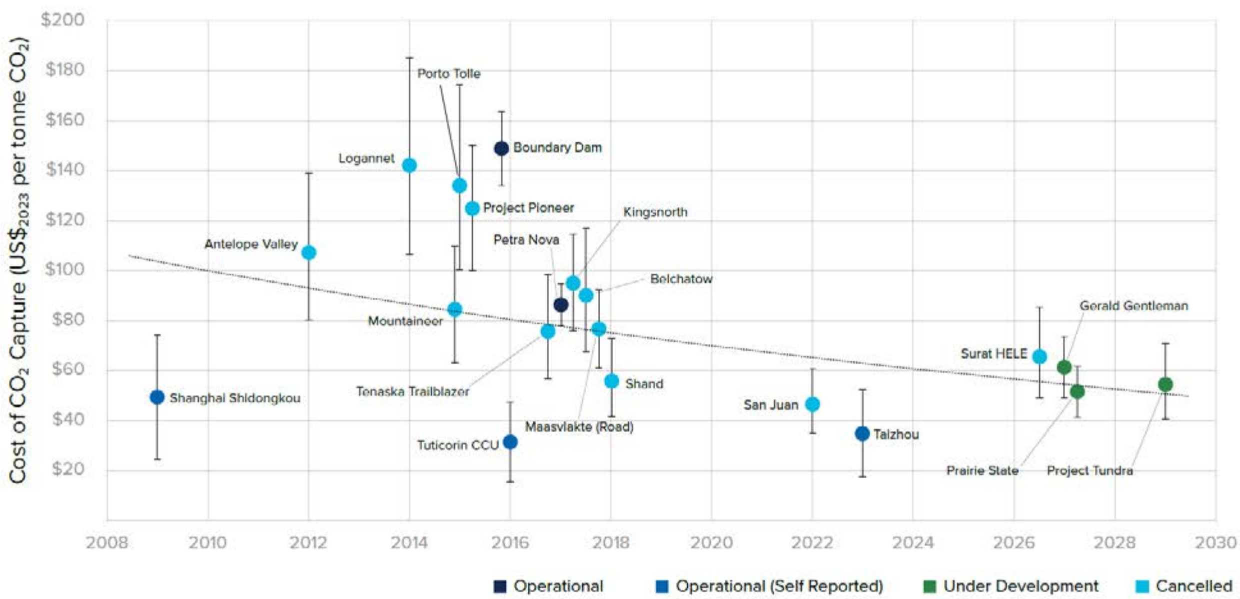

Figure 22. Expected cost declines for CCS[195]

[194] Richard A. Esposito et al., *Reconsidering CCS in the US fossil-fuel fired electricity industry under section 45Q tax credits* (2019) https://onlinelibrary.wiley.com/doi/abs/10.1002/ghg.1925.

[195] Global CCS Institute, *Advancements in CCS Technologies and Costs* (January 2025) https://www.globalccsinstitute.com/wp-content/uploads/2025/01/Advancements-in-CCS-Technologies-and-Costs-Report-2025.pdf [Attachment Q].

V. Co-Benefits

Many flue gas impurities—including particulates, sulfur dioxide,[196] sulfites,[197] and nitrogen oxides[198]—can degrade amine solvents. That fact means that installation of upstream controls for these pollutants—particularly the sulfur compounds and acid gasses—is considered to be a necessary precondition for the efficient operation of the post-combustion carbon capture equipment. This presents opportunities for combined reductions in both carbon dioxide and local air pollutants, where additional controls upstream of the capture equipment improve both emissions of local air pollutants and the efficiency of operation of the capture equipment.[199] The operation of the carbon dioxide capture system itself can also directly reduce emissions of some pollutants. In particular, amines react with NO_2, which accounts for around 40 percent of the NO_x found in NGCC exhaust, but only 5 to 10 percent of the NO_x in coal power plant flue gas. Power plants are unlikely to require additional NO_x controls in order to retrofit CO_2 capture, but in some cases such controls may be added in order to minimize the formation of certain degradation products, such as nitrosamines.

Pilot and demonstration-scale applications of amine-based capture systems on coal power have in nearly all cases included an additional 'SO_2 polishing' step which removes remaining SO_2 and SO_3 from the flue gas, even where it has already been treated with conventional flue gas desulfurization (FGD). Researchers indicate that SO_2 concentrations need to be below 10 ppmv for economic post-combustion capture using amines and even lower levels for some other technologies like membranes.[200] This polishing step is often carried out in the direct contact cooler (in which water is introduced to the hot flue gas for cooling), through addition of alkali species (NaOH, Na_2CO_3) to the cooling water. If not removed, SO_2 will react with amines to

[196] Shan Zhou, Shujuan Wang, Chenchen Sun, Changhe Chen, *SO_2 effect on degradation of MEA and some other amines*, 37 Energy Procedia 896 (2013), https://www.sciencedirect.com/science/article/pii/S187661021300194X.

[197] Takashi Kamijo et al., *SO3 Impact on Amine Emission and Emission Reduction Technology*, 37 Energy Procedia 1793 (2013), https://www.sciencedirect.com/science/article/pii/S1876610213002993 (flue gas SO3 results in additional amine emissions).

[198] Berit Fostås et al., *Effects of NOx in the flue gas degradation of MEA*, 4 Energy Procedia 1566 (2011), https://www.sciencedirect.com/science/article/pii/S1876610211002232.

[199] *See* Great Plains Institute, *Carbon Capture Co-benefits* (Aug. 2023); Amy B. Jordan et al., *Quantifying air quality co-benefits to industrial decarbonization: the local Air Emissions Tracking Atlas*, 24 Front. Pub. Health 1394678 (2024), https://doi.org/10.3389/fpubh.2024.1394678.

[200] *See, e.g.*, Kevin Smith, William Booth, & Stephane Crevecoeur, Carmeuse Lime & Stone, *Evaluation of Wet FGD Technologies to Meet Requirements for Post CO_2 Removal of Flue Gas Streams* (2008), https://www.mass.gov/doc/appendix-d25-exhibit-4-to-comments-from-scclf/download (EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, Paper #49); Sanjay Purswani & Daniel Shawhan, *How Clean Is Your Capture? Co-emissions from Planned US Power Plant Carbon Capture Projects* (July 2023), https://media.rff.org/documents/WP_23-29.pdf (RFF Working Paper 23-29).

form heat stable salts, which can alternatively be eliminated in the solvent reclaimer.[201] In both cases, SO_2 pollution in the flue gas will be reduced.

NO_2 can react with secondary amines to form nitrosamines, a regulated carcinogenic species whose formation and potential release has been shown to be controllable through mechanisms such as use of water washes.[202] Primary amines react with NO_2 to form unstable compounds that degrade into various species of less concern that can be removed in solvent reclaiming. For this reason, capture systems including secondary amines—particularly when applied to NGCC—may have an incentive to further reduce NO_x entering the capture system, in addition to any existing upstream NO_x controls. This could be done, for example, by adding sulfites or thiosulfates to the direct contact cooler.

Coal power plants produce particulates (fly ash) which are removed with particulate control devices such as baghouses and electrostatic precipitators. Where present, further removal of particulates is achieved by wet flue gas desulfurization. Solvent-based CO_2 capture technologies require very low concentrations of particulates entering the system, as they can cause unwanted fouling of process components such as heat exchangers; this was encountered during the early operation of Boundary Dam 3, where upstream controls were electrostatic precipitators that allowed some finer fly ash to pass through.[203] As a result, water sprays were later added to prevent particulates from entering the CO_2 capture system—also preventing them from reaching the air, as they had been previously. Most amine-based CO_2 capture processes also include a direct contact cooler, which also acts as an important trap for particulates in plants without wet desulfurization.[204]

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[201] Jon Gibbins & Mathieu Lucquiaud, *BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fuelled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK* (2022), https://ukccsrc.ac.uk/wp-content/uploads/2023/01/BAT-for-PCC_v2_EfW_web-1.pdf.

[202] Nathan A. Fine & Gary T. Rochelle, *Absorption of nitrogen oxides in aquerous amines*, Energy Procedia, Vol. 63 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214019092; Berit Fostås et al., *Effects of NOx in the flue gas degradation of MEA*, 4 Energy Procedia 1566 (2011), https://www.sciencedirect.com/science/article/pii/S1876610211002232; H. Kolderup et al., SINTEF Report A18095 on Emission Reducing Technologies (Feb. 14, 2011), https://gassnova.no/app/uploads/sites/6/2019/10/emissionredtechnologies_sintef.pdf.

[203] *Wood Report* [Attachment H].

[204] Jon Gibbins & Mathieu Lucquiaud, *BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fuelled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK* (2022), https://ukccsrc.ac.uk/wp-content/uploads/2023/01/BAT-for-PCC_v2_EfW_web-1.pdf.

A Resources for the Future working paper evaluated several coal plant FEED studies and determined that SO_2 pollution levels were expected to be reduced 99 percent.[205] Using this 99 percent SO_2 reduction, we estimate installing CCS on the fleet of 133 existing coal power plants over 300 MW capacity would cut 250,000 tons of SO_2 pollution each year. This includes reductions from plants with existing desulfurization units installed that are now operating under 99 percent capture efficiency as indicated by the EIA 860 report and is based on 2021 annual emissions as reported in eGRID.

Using a reduced form, spatially explicit tool based on a chemical transport model for calculating marginal social costs from health impacts and premature mortality from point source emissions called EASIUR, these co-pollutant reductions result in 4.33 billion dollars per year in avoided social costs.[206] This equates to 500 lives saved per year from SO_2 reductions alone.

VI. Water Consumption

Some carbon capture configurations can increase water consumption, primarily because of the cooling water required to cool down the CO_2-containing gasses before they are treated, as well as cooling other parts of the process. The amount of water consumed depends significantly on the type of cooling used by the plant and the CO_2 capture technology used, and does not necessarily increase relative to an unabated plant. The impact of carbon capture on water consumption depends on the type of cooling selected by the developer. There are three options for cooling coal and natural gas-fired power plants:[207]

1. Dry cooling (also called air cooling): Dry cooling systems reject heat in the plant's hot water directly to the atmosphere using air-cooled condensers (ACCs). These systems do not consume cooling water.

2. Wet cooling: A wet cooling tower cools hot water and recirculates it to a condenser. Cooling towers can be natural-draft or mechanical-draft. Water consumption can be highest if using an amine-based CO_2 capture system and closed-loop wet cooling, potentially representing a 20 to 30 percent increase for a coal power plant.[208]
3. Hybrid cooling: Hybrid cooling combines both the wet and dry cooling approaches. Generally, the plant uses dry cooling during cooler weather and wet cooling during hot periods when dry cooling systems are less effective.

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[205] Sanjay Purswani & Daniel Shawhan, *How Clean Is Your Capture? Co-emissions from Planned US Power Plant Carbon Capture Projects* (July 2023), https://media.rff.org/documents/WP_23-29.pdf (RFF Working Paper 23-29)

[206] Assuming a value of statistical life (VSL) of $8.7M in 2015$ per the BenMAP manual.

[207] Kevin Clark, *Evaluating the Economics of Alternative Cooling Technologies*, Power Engineering (Nov. 1, 2012), https://www.power-eng.com/coal/evaluat-economics-alternative-cool-technologies/.

[208] GCCSI, *Water use in thermal power plants equipped with CO_2 capture systems* at 44-45 (Sept. 2016), https://www.globalccsinstitute.com/archive/hub/publications/200603/Water%20use%20in%20thermal%20power%20plants%20equipped%20with%20CO2%20capture%20systems.pdf.

These three cooling options were detailed in a carbon capture context by the first proposed new coal plant with 90 percent capture to receive an air permit – Tenaska's 600 MW-n Trailblazer plant, which was to be located in Sweetwater, Texas.[209] The Trailblazer plant location had easy access to EOR fields and rail access for sub-bituminous low-rank coal but the site was water constrained. As part of the development process, the Global CCS Institute funded Tenaska to prepare a report that documented their cooling technology options and selection for the project.[210] Tenaska examined three options: wet cooling, hybrid cooling and dry cooling. For each configuration, they examined water consumption when the capture unit was turned on (capturing 90.5 percent of the plant's CO_2) and when the capture unit was off (no capture). Figure 23 summarizes in millions of gallons per day of water the average water consumption findings from the report:

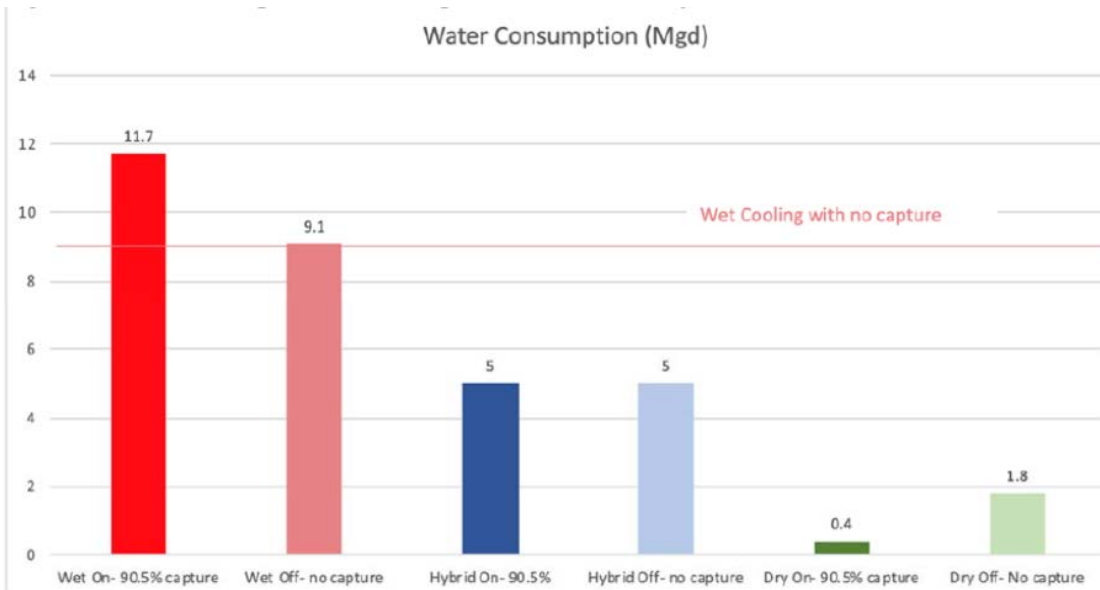

Figure 23. Water consumption for 90 percent capture; Tenaska Trailblazer coal plant[211]

As the figure shows, wet cooling requires the most water consumption. Using carbon capture increases the water consumption requirements by 29 percent on an average basis, although the range for this plant varied from 25–40 percent depending on ambient temperature conditions.[212] Dry cooling requires the least amount of water. Compared to wet cooling, dry cooling reduces

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[209] The plant was issued an air permit by the Texas Commission on Environmental Quality on December 30, 2010. EPA, *TX-0585*, RACT/BACT/LAER Clearinghouse (last updated: Feb. 3, 2020), https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.FacilityInfo&facility_id=27221.

[210] Tenaska Trailblazer Partners, LLC, *Cooling Alternatives Evaluation for a New Pulverized Coal Power Plant with Carbon Capture* (Aug. 2011), https://www.globalccsinstitute.com/archive/hub/publications/24367/cooling-study-report-2011-09-06-final-w-attachments.pdf.

[211] *Id.* at 21.

[212] *Id.*

water consumption by over 96 percent. Tenaska's report noted an important fact about carbon capture when using dry cooling, "the [Carbon Capture (CC)] Plant *decreases* water consumption by 40 – 80 percent which equals 0.8 to 1.4 mgd (3,028 – 5,300 m3/d) depending on the ambient condition. This is because the CC Plant includes an upfront cooling step that condenses combustion water vapor which is re-used in the PC Plant."[213] The hybrid case, which combines dry and wet cooling, reduced water consumption by more than half compared to the wet-cooled carbon capture case. Significantly, regardless of whether carbon capture was turned on or off, hybrid cooling consumed the same amount of water. Again, the condensed water from the carbon capture plant was sufficient to offset cooling requirements of carbon capture because the hybrid approach includes some dry cooling.

Tenaska found that both hybrid and dry cooling technology were available for their project, for which Fluor carried out the project design and costing. As Tenaska notes, "Fluor has determined that it is feasible to air cool the CC Plant Econamine FG+ technology and achieve the desired CO_2 capture rate at the Trailblazer site ambient conditions."[214] Dry cooling was also economic. Tenaska concluded that dry cooling was the lowest cost option for the Trailblazer plant.[215]

This finding that hybrid cooling does not lead to increased water consumption was affirmed by a feasibility study on SaskPower's Shand Plant.[216] The 305 MW Shand Plant burns low-rank lignite and is located in a water-constrained area. Using hybrid cooling, the feasibility found, "The only new water used in the system is the water that is condensed out of the unit's flue gas. The use of a hybrid cooling system with dry coolers and wet surface air coolers … has the potential to be a reasonable first approach to cooling at any coal-fired power plant and is especially effective with high moisture low-rank coals."[217]

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[213] *Id*. at 22.

[214] *Id.*

[215] *Id*. at 6. After the initial design work was completed, Tenaska received bids for the dry cooling option. These bids were higher than expected: "The result of the competitive bidding process for the air coolers was higher costs than were previously estimated. In addition, the final design included raising the height of the air coolers and including a lower design air velocity with an increased fin spacing. A 20 percent spare heat transfer surface area was included in the design basis, but variable frequency drives or two-speed fans were not considered. Had these impacts been known at the point in time when the cooling study was completed, the hybrid cooling option may have provided the lower evaluated cost (although its cost may have been affected somewhat similarly). Even so, with the lack of water available for the Project in semi-arid West Texas, there is a high probability that dry cooling still would be a necessity." *Id*. at 25.

[216] Int'l CCS Knowledge Ctr., *The Shand Feasibility Study* (Nov. 2018); https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

[217] *Id*. at 12.

VII. Space Constraints

CATF conducted a systematic assessment of land availability surrounding the existing U.S. fleet of coal and natural gas plants to determine the physical feasibility of retrofitting them with post-combustion carbon capture technology. While many plants likely have space within the existing plant boundary, this study focuses on adjacent land as a conservative way to assess the limitation. In some cases, it may be more cost effective to purchase more land rather than engineer around a crowded plant site, or a site may simply be too crowded such that additional land may be required to accommodate the retrofit facilities.[218] If a plant has the required area of land adjacent to its boundary, then regardless of whether or not it has land available within its boundary, we can consider a carbon capture retrofit as being spatially feasible.

Using an assumed footprint for carbon capture infrastructure based on demonstration sites, scaled accordingly to meet installed capacities and a maximum allowable distance of one mile from the plant boundary, CATF found that the vast majority of coal and NGCC plants in the US have land available in the immediate vicinity upon which capture infrastructure could be constructed. Across the entire U.S. fleet of coal and natural gas power plants greater than 300 MW, 133 coal plants and 140 NGCC plants (i.e. all but 2 and 3 plants, respectively) were found to have sufficient land availability for carbon capture retrofits (Table 9). Importantly, this is an underestimate of the number of candidate fossil fuel plants because it does not account for the likely case that land is available within the existing plant boundary. It is also likely a conservative estimate because the footprint of carbon capture facilities will decrease over time as we progress from demonstration sites to full scale installations.

Table 9. Results of the analysis showing the number of plants and associated percentage of total installed capacity that could feasibly be retrofitted with carbon capture from a land availability perspective.

	Available Land (# plants)	**No land for CC retrofit (# plants)**	**Total retrofittable capacity (GW)**	**Total Installed Capacity (GW)**	**Percentage MW Capturable (%)**
Coal	133	2	154	157	**98.2**
NGCC	140	3	124	126	**98.4**

Although one mile (about 1610 meters) was used as the maximum distance, it is important to note that the vast majority of plants (83 percent and 72 percent for coal and NGCC, respectively) have the nearest available plot of land within 100 meters of the plant boundary (Figure 24). This is significant because the shorter distance the flue gas must be transported, the more cost-efficient the process becomes.

[218] Christopher Nichols, *Coal-Fired Power Plants in the United States- Examination of the Costs of Retrofitting with CO_2 Capture Technology* (2019), https://www.globalccsinstitute.com/archive/hub/publications/119731/coal-fired-power-plants-us-examination-costs-retrofitting-co2-capture-technology.pdf.

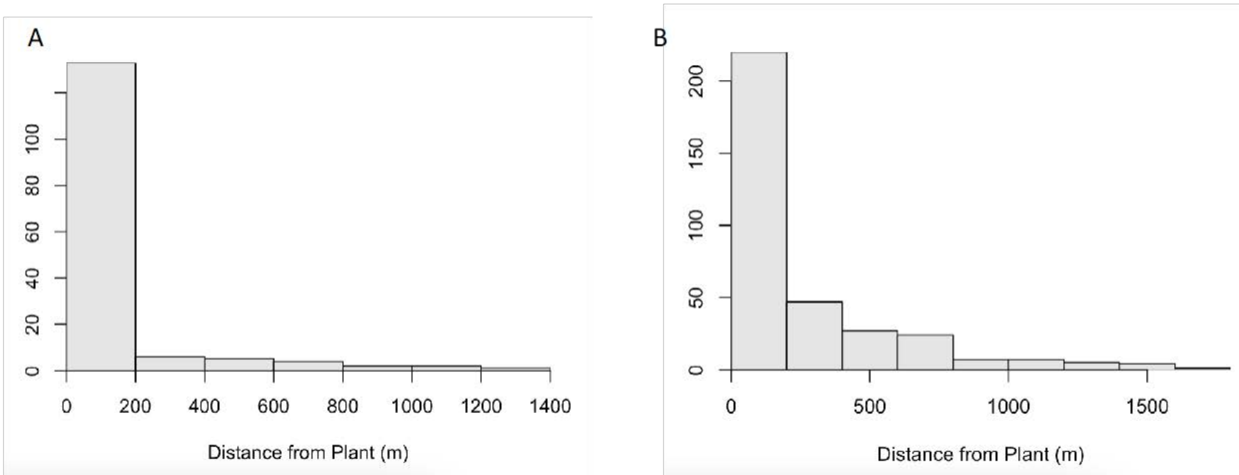

Figure 24. Histograms showing the distance between the nearest patch and the plant boundary in meters for A) Coal plants, and B) NGCC plants

VIII. Operational Flexibility

There is a growing body of research on the flexible operation of coal and gas power plants equipped with carbon capture. This research has included both modeling and large-scale pilot tests (for example, at Technology Centre Mongstad, CSIRO, PACT, and the University of Texas).[219]

The level of dynamic integration of power generation and CO_2 capture will differ according to whether the capture process is separately powered or uses steam extracted from the power plant's steam cycle. A 2020 study reviewed prior work in this field and conducted dynamic modeling of an integrated (615 MW) NGCC and CCS system.[220] In relation to load cycling operation, it concludes that "the decarbonization of an NGCC via post-combustion CO_2 capture does not appear to impose any limitation on the flexibility or operability of the underlying power plant in

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[219] Bui et al., *Demonstrating flexible operation of the Technology Centre Mongstad (TCM) CO_2 capture plant*, 93 Int'l J. Greenhouse Gas Control 102879 (2020), https://www.sciencedirect.com/science/article/abs/pii/S1750583615301687; Bui et al., *Evaluating Performance During Start-Up and Shut Down of the TCM CO_2 Capture Facility* (Nov. 23, 2022), Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16) 23-24 Oct 2022, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4284866; Bui et al., *Flexible operation of CSIRO's post-combustion CO_2 capture pilot plant at the AGL Loy Yang power station*, 48 Int'l J. GHG Control 188-203 (2016), https://www.sciencedirect.com/science/article/pii/S1750583615301687; Bui et al, *Dynamic operation and modelling of amine-based CO_2 capture at pilot scale*, 79 Int'l J. GHG Control 134-153 (2018), https://www.sciencedirect.com/science/article/pii/S1750583618304250.

[220] Rua et al., *Does CCS reduce power generation flexibility? A dynamic study of combined cycles with post-combustion CO_2 capture*, 95 Int'l J. GHG Control 102984 (2020), https://www.sciencedirect.com/science/article/pii/S1750583619306747.

terms of power generation."[221] Flexibility of the integrated plants can benefit from buffering provided by large liquid hold-ups (e.g., through larger solvent vessels), as well as advanced system controls such as model predictive control (which are now standard for power plants but require optimization for CCS-integrated systems). Testing flexible operation of CO_2 capture on gas-fired turbine flue gas at Technology Centre Mongstad found that high capture rates could be maintained throughout ramping up and down of the host unit, simply by ensuring a constant liquid-to-gas ratio in the absorber.[222] This study also notes that, given that dynamic behavior of NGCC is dictated mainly by the gas turbine rather than the steam cycle, steam extraction for the capture plant may have a negligible effect on the overall electricity output.

Coal power plants operating at low loads may encounter limited availability of steam at the necessary conditions for solvent regeneration, creating a negative impact on capture rate. However, this only occurs when steam is extracted from the steam cycle in an 'uncontrolled' fashion. This configuration extracts steam directly from the steam cycle, typically at the crossover point between intermediate and low pressure turbines. Controlling the pressure of extracted steam, using a valve between the extraction point and low pressure turbine, can ensure designed capture rates are maintained and even exceeded at lower loads.[223]

Rapid start-up of capture-equipped power plants may be hindered by the slower start-up times of the capture plant (particularly for cold start-ups). There are several commonly proposed approaches to mitigating this effect. These include the use of dedicated solvent storage, which allows CO_2 to be captured before the solvent regenerator reaches operating temperatures (solvent storage can also be used to optimize power plant operation according to varying electricity demand and price).[224] Alternatively, a small heater or auxiliary boiler (potentially electrically powered) can be used to provide preheating or additional steam for solvent regeneration. A detailed modeling study for the UK government in 2020 examined means of accelerating start-up and shut-down times of a state-of-the-art gas-fired power plant with CCS (steam extraction for solvent regeneration).[225] Four modified plant configurations were proposed to enhance capture rates during start-ups, including segregating solvent inventory between the regenerator and absorber loops during start-up; additional solvent buffer storage; dedicated heat storage for

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[221] *Id.*

[222] Bui et al., *Demonstrating flexible operation of the Technology Centre Mongstad (TCM) CO_2 capture plant*, 93 Int'l J. Greenhouse Gas Control 102879 (2020), https://www.sciencedirect.com/science/article/abs/pii/S1750583615301687

[223] Lucquiaud M and Gibbins J (2011) Steam cycle options for the retrofit of coal and gas power plants with postcombustion capture, *Energy Procedia;* 4; 1812-1819; International CCS Knowledge Centre. *The Shand CCS Feasibility Study Public Report* (November 2018), https://enchantenergy.com/wp-content/uploads/2022/09/Shand-CCS-Feasibility-Study-Public-_Full-Report_NOV2018.pdf

[224] Niall Mac Dowell & Neelkumar Shah, *Optimisation of Post-combustion CO_2 Capture for Flexible Operation*, 63 Energy Procedia 1525 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214019778.

[225] U.K. Dep't for Bus., Energy & Indus. Strategy, *Start-up and shut-down of power carbon capture, usage and storage (CCUS) facilities*, BEIS No. 2020/031 (Aug. 17, 2020), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/929284/AECOM_report_final_version_clean_inc_appendices.pdf.

regenerator preheating; and fast-starting steam cycle technologies or high-pressure bypass extraction. Each of these approaches was determined to be suitable for maintaining capture rates above 95 percent throughout start-up, except for segregated solvent inventory (87 percent); this option could, however, be used in combination with other methods to reduce costs.

As a result of this growing understanding of capture plant flexibility, developers of the planned NGCC with CCS in the UK are confident that the facilities will be able to operate in the UK grid while maintaining average capture rates at levels commensurate with proposed UK funding requirements. Environmental permitting for these facilities requires the operator to maximize carbon capture during start-up and shut-down periods, in addition to the requirement of at least 95% capture under normal operation.[226] As a consequence, proposed projects have tested their designs against flexible operating regimes, including 200 start-up shut-down events of various types (cold, warm, hot).[227] The environmental permit decision for the Net Zero Teesside Power plant records that the plant will adopt a range of measures to maximize capture rates during flexible operation and start-up and shut-down cycles, including increased insulation to reduce heat loss, use of an electric auxiliary boiler to provide heat and steam during start-up and shut-down, and optimizing lean solvent inventory.[228] These techniques are required to achieve equivalent results to solvent storage, which is identified as 'best available technology' by the permitting authority. Given that the capacity factors of combined cycle plants in the UK have declined to an average of 35 percent in 2020, CCS-equipped NGCC can be expected to operate in a highly flexible manner (although they will be dispatched ahead of unabated plants).

The UK government funded FOCUSS project, led by SSE Thermal and involving the U.S. National Carbon Capture Center, ran from 2021 to 2025 with the aim of reducing the cost of achieving very high capture rates (up to 99 percent) during flexible operation.[229] Results from this project presented in 2024 highlight the significant potential for use of 'early steam' and solvent storage in mitigating the impact of startup–shutdown cycles on overall capture rate.[230] Combined cycle gas turbines produce significant quantities of steam during start-up which is conventionally dumped into the condenser. This steam can instead be expanded and used for solvent generation, prior to the availability of steam which is conventionally extracted from

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[226] Environment Agency (2024) *Determination of an environmental permit under the environmental permitting (England & Wales) Regulations 2016*. EPR/PP3501LR,*available at* https://assets.publishing.service.gov.uk/media/6644a4d4b7249a4c6e9d3508/Application_Bespoke_Decision_Document_-_14052024.pdf.

[227]Aker Carbon Capture & CATF (2023) (market discussion with CATF staff).

[228] *Supra.* n. 226.

[229] University of Sheffield's Translational Energy Research Centre (TERC), *Carbon capture rates in FOCUSS as SSE Thermal secures grant from BEIS* (May 31, 2022), https://terc.ac.uk/news-events/carbon-capture-rates-in-focuss-sse-grant-beis/.

[230] Daniel Mullen et al., *Flexibly Operated Capture Using Solvent Storage (FOCUSS) – Results*, Proceedings of the 17th Greenhouse Gas Control Technologies Conference (GHGT-17) 20-24 (2024), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5062762.

between the intermediate and low-pressure steam turbines. Excess steam is similarly available during shutdown, when steam produced in the heat recovery steam generator (HRSG) becomes unsuitable for the steam turbine - this steam can also be used to help maintain capture plant performance during the shutdown sequence. The authors demonstrate that use of this surplus steam can dramatically reduce the scale of solvent storage required to maintain above 95 percent capture rates during startup and shutdown.

IX. Parasitic Load

Like most pollutant control technologies, CO_2 capture requires energy to run and will reduce the net power output of the plant. For the solvent-based capture processes mostly considered for power plants today, this penalty is largely associated with the heat energy needed to separate CO_2 from the solvent in the desorber/stripper. This heat is usually supplied by steam which can either be extracted from the power plant's own steam cycle (prior to the low-pressure turbine) or generated by a separate unit. Additional electrical energy is also required to compress CO_2 and run various fans and pumps needed to drive the capture process.

A detailed techno-economic analysis carried out by Wood Group for the IEA Greenhouse Gas R&D Programme determined some benchmark energy penalties for new coal-fired power plants (1000 MW) and NGCC plants (1500 MW) equipped with CCS.[231] This study found the coal plant would incur a 20 percent reduction in net efficiency at 90 percent capture rate, and a 24 percent reduction for 99 percent capture. The NGCC plant suffers only a 10 percent loss of net output at 90 percent capture, and a 12.6 percent penalty at 99 percent capture. NETL benchmark retrofit cases indicate energy penalties of between 11 percent and 12.5 percent for various NGCC cases with 90 and 95 percent capture. The UK's BAT review for post-combustion capture also states the energy penalty "will correspond to between approximately an eighth (for gas) and a quarter (for biomass) of the power plant's electricity output without CO_2 capture" (bearing in mind biomass power plants are roughly equivalent to coal in this context). Figure 25 indicates how the energy output penalty (EOP) can vary with capture rate.

[231] *Wood Report* [Attachment H].

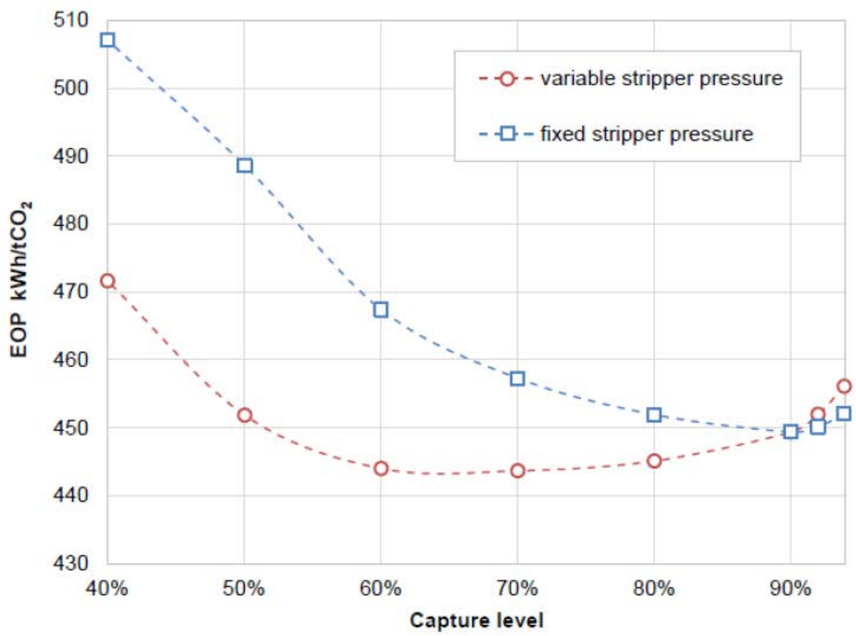

Figure 25. Total electricity output penalty of CO_2 capture and compression at different capture levels under variable and fixed stripper pressure operation[232]

The FEED studies detailed in Tables 2 and 3 can provide an indication of typical energy penalties for retrofit cases on coal and gas plants. Plant Daniel NGCC has a total net output of 525 MW without CCS, which is calculated to be reduced by 79 MW (15 percent) when 90 percent capture is applied. Panda Sherman NGCC (total net output 719 MW) incurs a penalty of 67.3 MW (16 percent) capturing 85 percent of a flue gas slipstream equivalent to 420 MW. Mustang NGCC uses additional boilers (rather than steam extraction from the power plant) to drive the CO_2 capture process, but the equivalent energy penalty can be calculated as 106 MW over 480 MW gross output (22 percent).

For coal plants, the repowered Boundary Dam Unit 3 generates around 150 MW net output without CCS, and 115 MW with CCS (a 24 percent energy penalty); however, this penalty also includes the operation of the desulfurization unit.

X. Construction Timeline

Evidence from operational, under construction, and planned large-scale CO_2 capture plants indicates that they typically take around two to three years to complete construction (Table 10). These construction times may be expected to accelerate as experience grows and equipment

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[232] Olivia Errey, *Variable capture levels of carbon dioxide from natural gas combined cycle power plant with integrated post-combustion capture in low carbon electricity markets* (2018), https://era.ed.ac.uk/bitstream/handle/1842/33240/Errey2018.pdf?sequence=1&isAllowed=y.

becomes more standardized. However, supply chains for key components may also require scaling up to prevent bottlenecks.

Table 10. Construction timelines of some large-scale CO_2 capture plants using amine solvent technology

Project	Capacity (Mt/year)	FID	Construction start	Expected or actual completion
Boundary Dam[233]	1	2010	Early 2011	Dec 2013
Petra Nova[234]	1.4	Early 2014	Sep 2014	Jan 2017
Quest (hydrogen)[235]	1.2	2012	Sep 2012	Aug 2015
Brevik (cement)[236]	0.4	2021	Jan 2021	Early 2024
Heidelberg Materials Edmonton (cement)[237]	0.6	Expected 2023	Not started	Late 2026
Net Zero Teesside Power (NGCC)[238]	2	Expected Q1 2024	Not started	2027
Genesee CCS project (NGCC)[239]	~3	Expected 2023	Not started	2027
Orsted Asnaes and Avedore (two biomass CHP)[240]	0.15 and 0.28	May 2023	Not started	Early 2026

XI. Downtime Analysis

Commenters performed a downtime analysis, using EPA's Clean Air Markets Program Data.[241] The sample includes 12 existing coal-fired powered units across five plants, selected to represent a variety of ages, locations, ownership types, fuel types, sizes, and existing control equipment.

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233 IEAGHG, *Integrated carbon capture and storage project at Saskpower's Boundary Dam power station* (2015), https://ieaghg.org/docs/General_Docs/Reports/2015-06.pdf.

234 Petra Nova, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report* (2020), https://www.osti.gov/servlets/purl/1608572.

235 IEAGHG, *The Shell Quest Carbon Capture and Storage Project* (2019), https://documents.ieaghg.org/index.php/s/5LUE9dQjnqPIKCr.

236 Heidelberg Materials, *Project status Brevik CCS*, Brevik CCS (2023), https://www.brevikccs.com/en/status.

237 *First global net zero carbon capture and storage facility in the cement industry: Heidelberg Materials partners with the Government of Canada*, Heidelberg Materials (Apr. 6, 2023), https://www.heidelbergmaterials.com/en/pr-2023-04-06.

238 *Net Zero Teesside (NZT) Power named on DESNZ's Track 1 Negotiations Project List*, Net Zero Teesside (Mar. 30, 2023), https://www.netzeroteesside.co.uk/news/net-zero-teesside-nzt-power-named-on-desnzs-track-1-project-negotiation-list/.

239 *Capital Power advances plans for Genesee CCS Project*, Capital Power (Dec. 1, 2022), https://www.capitalpower.com/media/media_releases/capital-power-advances-plans-for-genesee-ccs-project/.

240 *Ørsted awarded contract – will capture and store 430,000 tons of biogenic CO2*, Ørsted (May 15, 2023), https://orsted.com/en/media/newsroom/news/2023/05/20230515676011.

241 *See* EPA, *Clean Air Markets Program Data*, https://campd.epa.gov/ (last visited July 30, 2025).

See Table 11 for details on the sample plants and Figures 26a-26e for operational performance over 2019 to 2024.

Table 11. Selected Coal-Fired Power Units for Downtime Pattern Analysis.

Plant Name	Operator Name	Online Year(s)	Plant State	Ownership	Reported Fuel Type Code	Balancing Authority Code	Total Plant MW	Annual CF	Pollution Control Equipment
Bowen	Georgia Power Co	1971-1975	GA	Electric Utility	BIT	SOCO	2,675 (4 units)	35%	FGD, Selective catalytic reduction, Low NO_x burner, Baghouse (Units 3-4), Electrostatic precipitator, Wet scrubber
Antelope Valley	Basin Electric Power Coop	1984-1986	ND	Electric Utility	LIG	SWPP	1,766 (2 units)	62%	FGD, Low NO_x burner, Baghouse, spray dryer
Gavin Power, LLC	Gavin Power, LLC	1975	OH	IPP	BIT	PJM	1,396 (2 units)	45%	FGD, Selective catalytic reduction, Low NO_x burner, electrostatic precipitator, wet scrubber
Prairie State Generating Station	Prairie State Generating Co LLC	2012	IL	IPP	BIT	MISO	1,387 (2 units)	74%	FGD, Selective catalytic reduction, Low NO_x burner, Electrostatic precipitator, wet scrubber
Keystone	KeyCon Operating LLC	1968	PA	IPP	BIT	PJM	681 (2 units)	19%	FGD, Selective catalytic reduction,

									Low NO_x burner, Electrostatic precipitator, wet scrubber

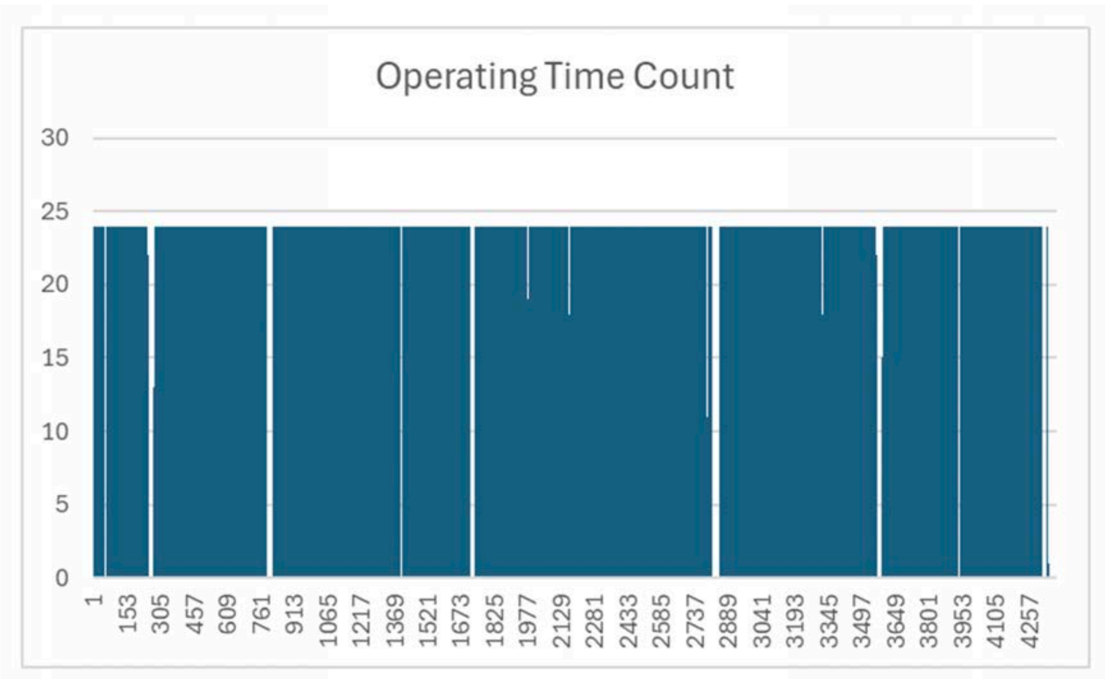

Figure 26a. Prairie State operated 87.8 percent of the time (2019-2024)

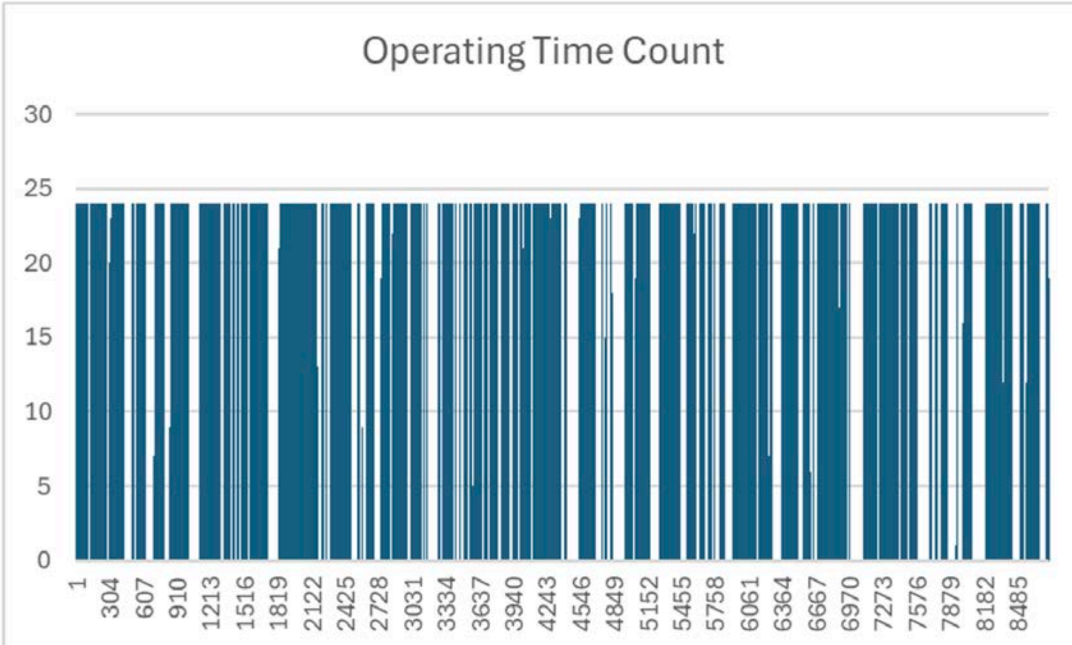

Figure 26b. Bowen (2 units) operated 53 percent of the time (2019-2024)

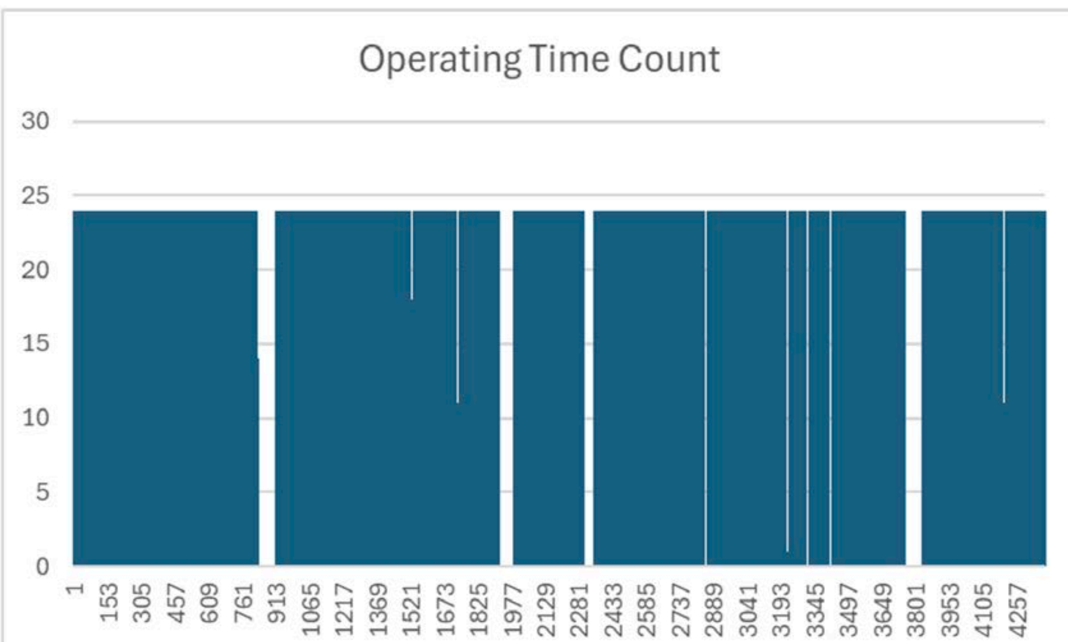

Figure 26c. Antelope Valley operated 86 percent of the time (2019-2024)

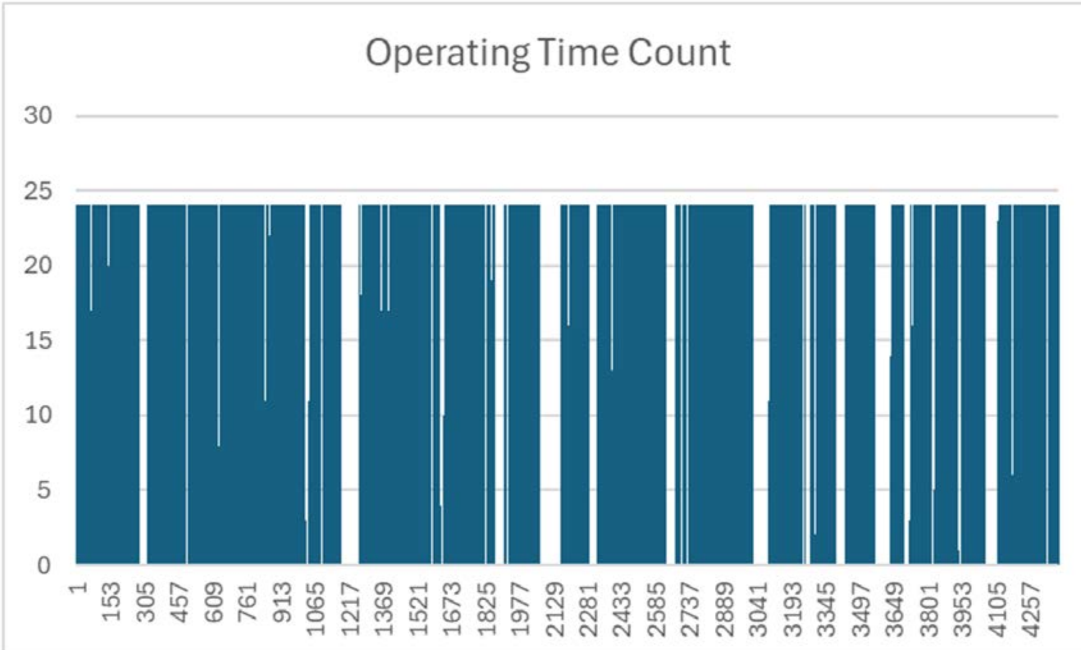

Figure 26d. Gavin (2 units) operated 73 percent of the time (2019-2024)

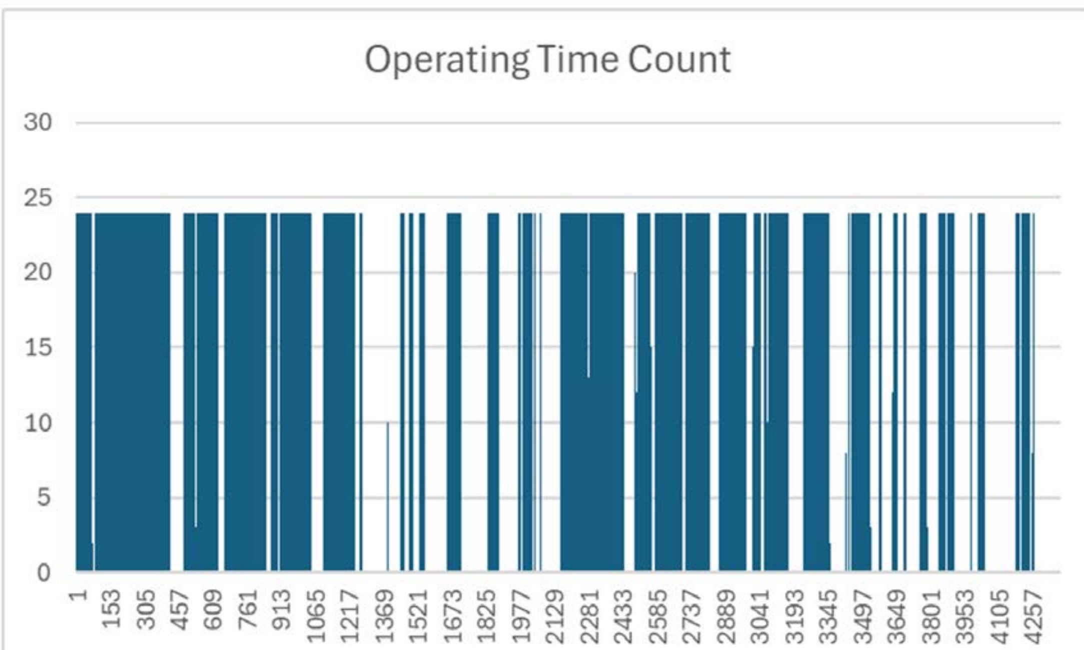

Figure 26e. Keystone operated 54 percent of the time (2019-2024)