# Greenhouse Gas Mitigation Measures

## Carbon Capture and Storage for Combustion Turbines

### Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

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## Introduction

This document describes the EPA's approach to estimating the costs of carbon dioxide ($CO_2$) capture and storage (CCS) on combined cycle combustion turbine EGUs. The primary source of this information for CCS installation on new plants is the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) baseline report. The EPA extrapolated the NETL Baseline report's partial $CO_2$ capture data to estimate the costs for CCS projects of different sizes. The EPA used the NETL CCS retrofit report to estimate the costs of CCS for existing combined cycle EGUs.

CCS involves the separation and capture of $CO_2$ from a gas, the pressurization and transportation via pipeline of the captured $CO_2$ (if necessary), and utilization or long-term geologic storage (also referred to as geologic sequestration). Equipping an EGU with CCS prevents emissions but also requires energy and decreases the efficiency of the EGU.

A separate TSD[1] discusses four categories of post-combustion carbon capture: absorption, adsorption, membranes, and cryogenic. Absorption is the uptake of $CO_2$ into the bulk phase that forms a chemical or physical bond to a solvent or other carrier material. Adsorption is a physical or chemical binding to a solid sorbent surface. Membranes separate $CO_2$ from the bulk gas using variations in molecular permeation rates through porous material based on the different molecular structure of $CO_2$. Cryogenic separation processes use the difference in boiling points of gasses to separate them via condensation. All four categories are equally applicable to natural gas- and coal-fired flue gas and other industrial sources of emissions. Current post-combustion $CO_2$ capture projects have primarily used amine solvent adsorption capture systems. This document describes carbon capture technologies, combustion turbine-specific applications, planned projects, feed studies, and the EPA's methodology to estimate the costs of CCS for combustion turbines. The separate *Greenhouse Gas Mitigation Measures for Steam Generating Units* TSD should be consulted for additional discussion of CCS, including technology development, incentives, deployment, and transportation and storage of captured $CO_2$.

[1] See the *Greenhouse Gas Mitigation Measures for Steam Generating Units* TSD in Docket ID No. EPA-HQ-OAR-2023-0072.

## CCS Costing Approaches for New Natural Gas-fired Combined Cycle EGUs

For the 40 CFR part 60, subpart TTTTa BSER analysis, the EPA estimated the costs of CCS using the NETL report titled, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (DOE/NETL - 2023/4320, October 14, 2022). This report provides detailed costing for 90 percent and 95 percent carbon capture rates for large natural gas-fired combined cycle combustion turbines and large subcritical and supercritical pulverized bituminous coal-fired steam generating EGUs. While this report provides detailed costing information for full capture for large EGUs, it does not provide information on the costs of partial CCS or the costs for smaller EGUs.

Estimating CCS Costs for Various Sizes of New Natural Gas-fired Combined Cycle EGUs

To estimate the costs of partial CCS and the costs for smaller EGUs, the EPA assumed that the CCS costs for combustion turbine EGUs follow the same general economies of scale/trends as for coal-fired EGUs and used the NETL report titled, *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to $CO_2$ Capture Rate in Coal-Fired Power Plants* (DOE/NETL-2019, December 23, 2020). The 2020 report includes detailed costing information for various percentages of partial CCS for large supercritical pulverized bituminous coal-fired steam generating EGUs. Using the information in the partial capture case, the EPA developed trend lines (*i.e.*, curve fits) for the capital, fixed, and variable operating costs based on the design capture rate (in tonnes of $CO_2$ captured per hour) of the carbon capture equipment. The EPA then used the derived equation to determine the capital, fixed, and variable operating costs of carbon capture equipment for various sizes of carbon capture equipment. These costs are specific to 90 percent capture of the $CO_2$ in the flue gas from a bituminous pulverized coal-fired steam generating EGU.

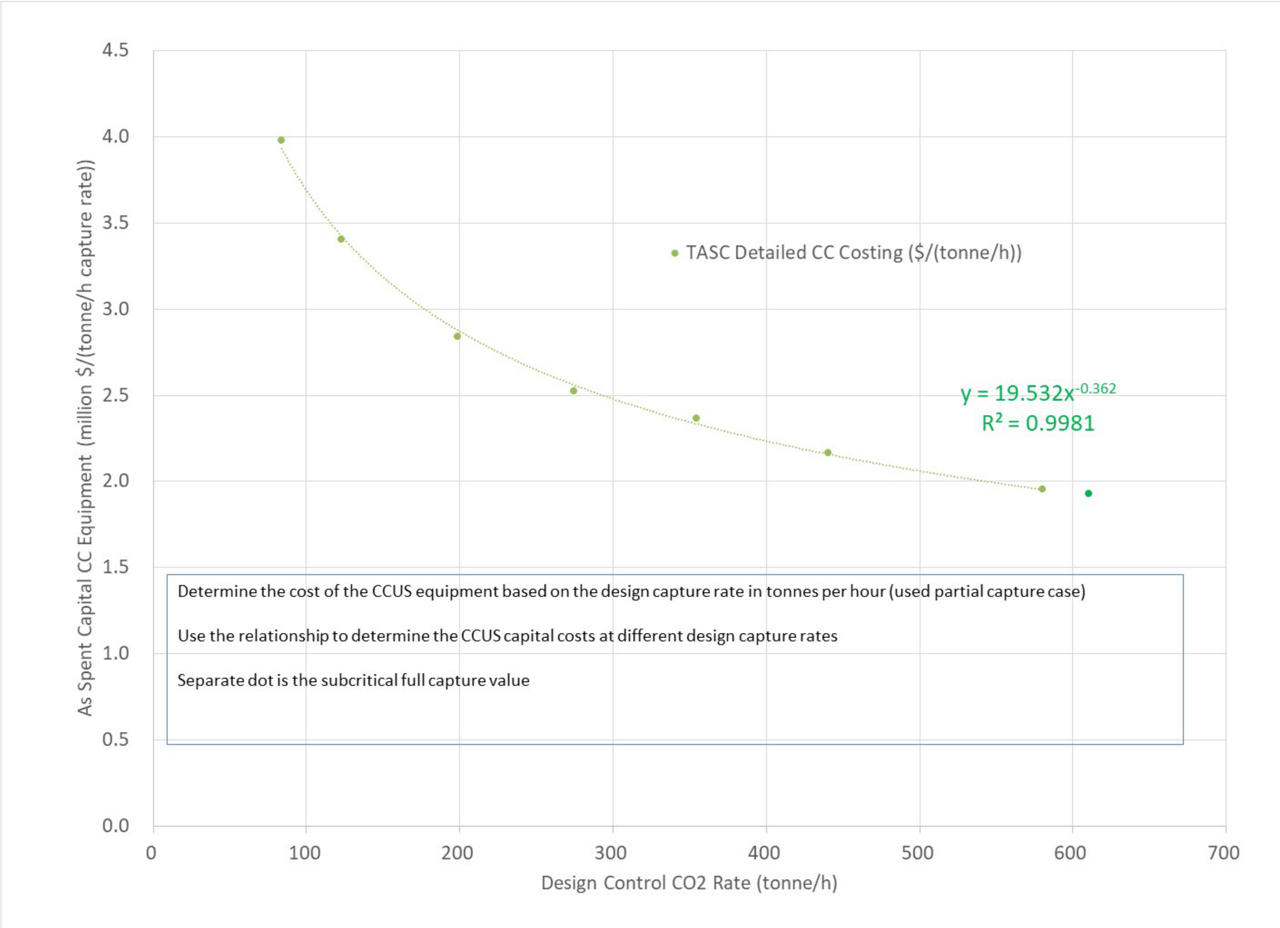
The EPA used the following approach to determine the capital costs of the carbon capture equipment:

- First, the EPA used the detailed equipment costs from the NETL full capture case and compared those detailed costs to the detailed costs for the supercritical bituminous coal-fired non-capture case. These costs could then be used to determine the reduction in costs of the boiler island itself due to economies of scale. The EPA then made a simplifying assumption that the boiler island economies of scale are linear. This allowed the EPA to estimate the boiler island costs for the various partial capture cases.[2]
- Next, the EPA compared the estimated carbon capture equipment costs in the detailed costing information to the carbon capture costs estimated from subtracting the boiler island costs from the total costs of the EGU. From this, the EPA used the ratio of costs to reduce the estimated costs of the carbon capture equipment.
- The EPA used these values in the partial capture report and divided those costs by the design capture rate in tonnes of $CO_2$ per hour. The EPA then plotted the 'as spent capital' costs against the capture rate to determine the economies of scale of capture equipment. Figure 1 shows the relationship between the 'as spent capital' and capture rate. Equation 1 shows the 'as spent capital' of the carbon capture equipment in millions of $ per tonne per hour $CO_2$ capture rate.

$$As\ Spent\ Capital = 19.532 * Design\ Capture\ Rate^{-0.362}$$

[2] Detailed costing information was not included in the partial capture cases. Since the NETL analysis assumes a constant net output, the boiler island itself is larger as the level of CCS is increased.

Figure 1: Capital Cost of CCS Equipment




Similarly, the EPA determined the annual fixed costs and variable operating costs at the different partial capture rates to determine the annual fixed costs and variable operating costs of the capture cases compared to the non-capture case. The EPA did not apply any adjustments for economies of scale to either of these values. Figures 2 and 3 show the relationship between fixed and variable costs and the design $CO_2$ control rate.

Figure 2: Fixed Costs of CCS

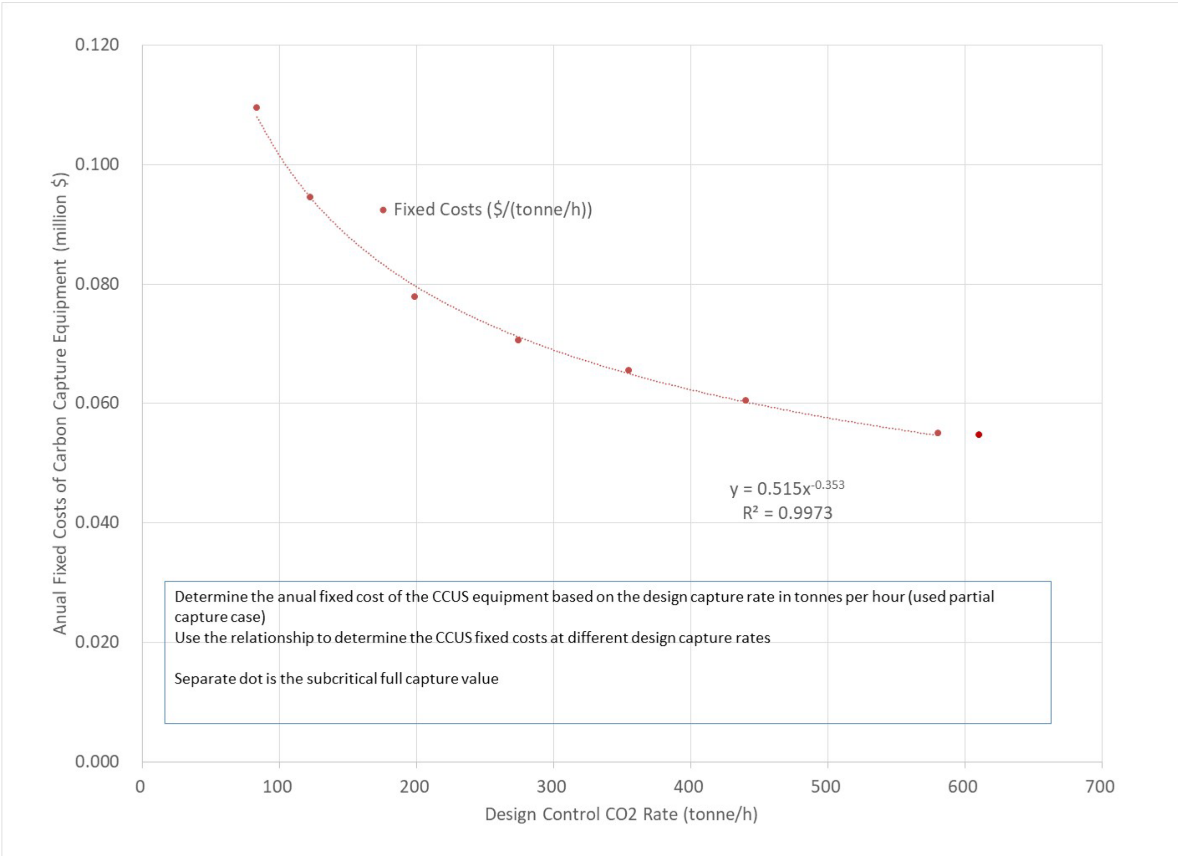
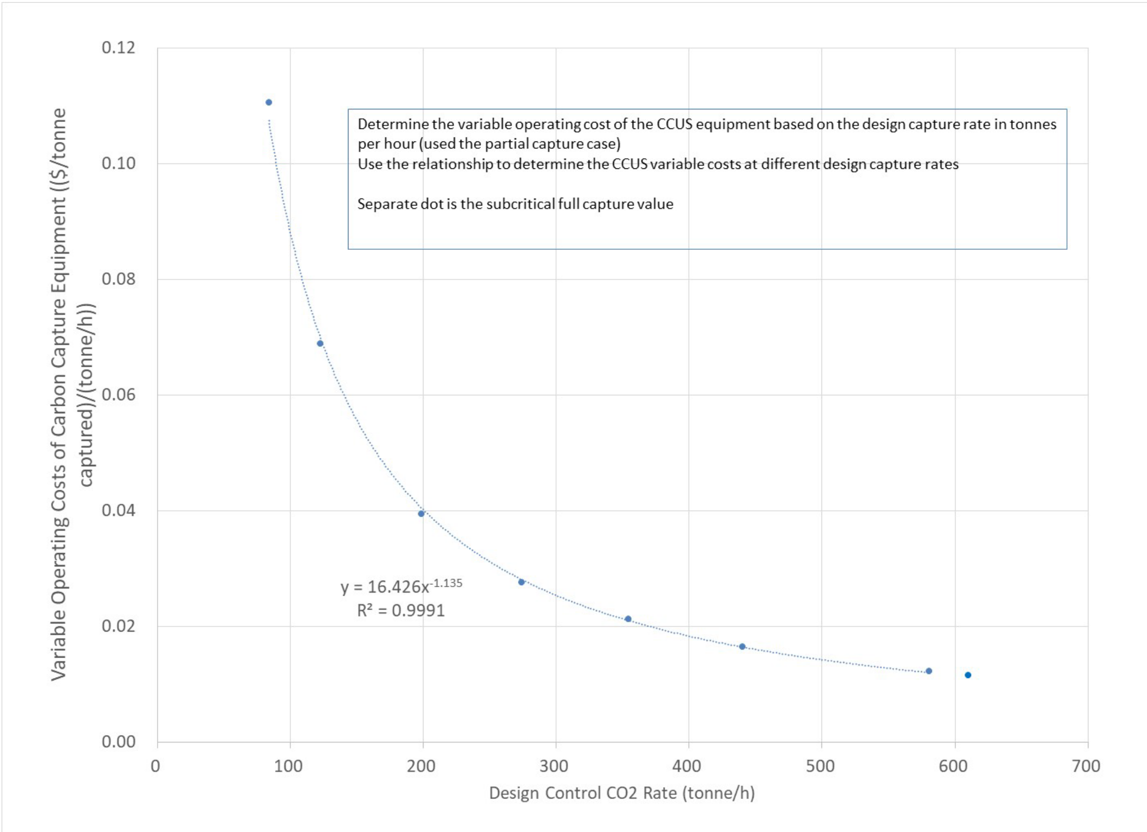


Figure 3: Variable Operating Costs of CCS




$$Fixed\ Costs\ of\ Carbon\ Capture\ Equipment = 0.515 * Design\ CO2\ Control\ Rate^{-0.353}$$

$$Variable\ Operating\ Costs\ of\ CC\ Equipment = 16.426 * Design\ CO2\ Control\ Rate^{-1.135}$$

These equations can be used to determine the capital, fixed, and variable operating costs of different sizes of carbon capture equipment for a new coal-fired steam generating EGU.

Updating Derived Cost Curves

The costs in the 2020 NETL report are based on a previous version of the 2022 report.[3] The primary difference between the 2020 and 2022 full capture reports are (1) the cost of CCS is lower, (2) an additional larger natural gas-fired combined cycle combustion turbine was added to the analysis, and (3) higher rates of capture were included.[4] To adjust the curves from the 2020 report, the EPA determined the ratio of the full capture capital, fixed, and variable operating costs in the 2022 and 2019 versions of the NETL baseline report. Those values are shown in Figure 4.

[3] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (NETL-PUB-22638, September 24, 2019)
[4] CCS costs were provided for 95 percent and 97 percent for combined cycle EGUs and 95 percent and 99 percent for bituminous coal-fired EGUs.

Figure 4. 90 Percent Capture CCS Cost
The 2022 and 2019 reports have 90 percent capture rates of 578 and 580 tonnes $CO_2$/h, respectively

| Cost | 2019 NETL Report | 2022 NETL Report | Ratio[5] |
|---|---|---|---|
| As Spent Capital CC Equipment (million $/(tonne/h)) | 1.45 | 1.95 | 0.74 |
| Annual Fixed Costs of Carbon Capture Equipment (million $/(tonne/h)) | 0.044 | 0.055 | 0.81 |
| Variable Operating Costs of Carbon Capture Equipment (($/tonne captured)/(tonne/h)) | 0.011 | 0.012 | 0.88 |

The EPA applied the cost ratios to the costs in the 2019 report to estimate the costs of CCS for bituminous coal-fired steam generating EGUs at different design capture rates. The EPA used the ratio of the costs to estimate updated capital, fixed, and variable operating costs for carbon capture equipment on new coal-fired steam generating EGUs. The revised equations are below:

$$As\ Spent\ Capital = 14.454 * Design\ Capture\ Rate^{-0.362}$$

$$Fixed\ Costs\ of\ Carbon\ Capture\ Equipment = 0.417 * Design\ CO2\ Control\ Rate^{-0.353}$$

$$Variable\ Operating\ Costs\ of\ CC\ Equipment = 14.455 * Design\ CO2\ Control\ Rate^{-1.135}$$

Costs of CCS for New Natural Gas-Fired Combined Cycle EGU

The EPA used the 2022 NETL report directly to estimate the costs of 90 percent CCS for large natural gas-fired combined cycle combustion turbines. To estimate the costs of partial capture and for small combined cycle combustion turbines, the EPA used the relative difference in costs of 90 percent CCS for bituminous coal-fired steam generating EGUs to the combined cycle combustion turbine EGUs. Figure 5 shows the relative costs of CCS of natural gas-fired combined cycle combustion turbine EGUs to bituminous coal-fired steam generating EGUs:

[5] No adjustment was made to capital, fixed, or variable operating costs.

Figure 5. 90 Percent Capture CCS Cost
F-Class Combined Cycle capture rate is 225 tonnes $CO_2$ per hour
H-Class Combined Cycle capture rate is 299 tonnes $CO_2$ per hour

| Cost | F-Class Combined Cycle | Bituminous-Fired EGU | H-Class Combined Cycle | Bituminous-Fired EGU | Average Ratio |
|---|---|---|---|---|---|
| As Spent Capital CC Equipment (million $/(tonne/h)) | 3.07 | 2.03 | 2.73 | 1.84 | 1.50 |
| Annual Fixed Costs of Carbon Capture Equipment (million $/(tonne/h)) | 0.072 | 0.062 | 0.063 | 0.056 | 1.15 |
| Variable Operating Costs of Carbon Capture Equipment (($/tonne captured)/(tonne/h)) | 0.027 | 0.031 | 0.019 | 0.022 | 0.85 |

The EPA then applied the ratio of costs to the bituminous coal-fired steam generating EGU partial capture case to develop CCS cost curves for natural gas-fired combined cycle combustion turbines. The cost curves are shown in the following equations:

$$As\ Spent\ Capital = 21.567 * Design\ Capture\ Rate^{-0.362}$$

$$Fixed\ Costs\ of\ Carbon\ Capture\ Equipment = 0.478 * Design\ CO2\ Control\ Rate^{-0.353}$$

$$Variable\ Operating\ Costs\ of\ CC\ Equipment = 12.243 * Design\ CO2\ Control\ Rate^{-1.135}$$

The EPA used the equations to estimate the costs of carbon capture equipment for different sizes of combined cycle combustion turbine EGUs. Based on review of design and reported emissions rates, the EPA concluded that the efficiency of the NETL baseline facility is representative of the efficiency for all combine cycle combustion turbines larger than 2,000 MMBtu/h. Based on review of design and reported emissions rates, for smaller combined cycle combustion turbines with base load ratings less than 2,000 MMBtu/h, the EPA increased the efficiency linearly to 880 lb $CO_2$/MWh-net at 250 MMBtu/h.[6] The EPA assumed that the efficiency penalty of the CCS equipment is a linear relationship and used the increase in heat rate for the F-Class and H-Class combined cycle combustion turbines to estimate the relationship shown in Figure 6.

[6] The NETL design emissions rate for a new F-class combined cycle combustion turbine is 760 lb $CO_2$/MWh-net. The EPA applied the ratio of the NETL design efficiency to the proposed emissions standard of 770 lb $CO_2$/MWh-gross (0.98) to the proposed emissions rate for small base load combustion turbines, 900 lb $CO_2$/MWh-gross.

Figure 6. CCS Heat Rate Impact for Combined Cycle EGUs

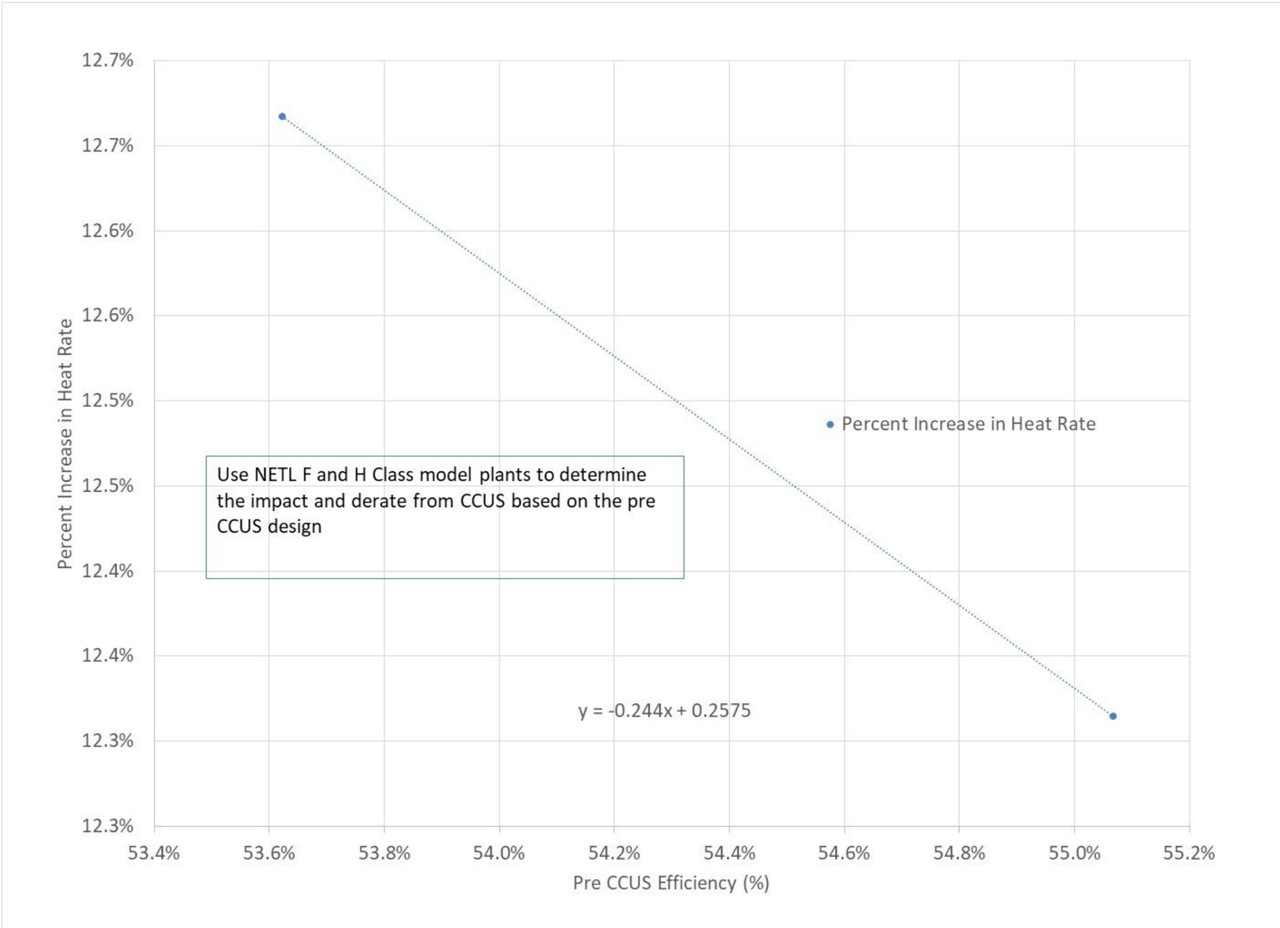



Figure 7 shows the NETL estimated CCS costs along with the EPA estimated costs for a smaller 2,000 MMBtu/h combined cycle combustion turbine. The costing analysis the EPA used only provides the incremental costs of the CCS system and not the costs of the combined cycle combustion turbine itself. Figure 8 shows the costs of CCS varies with the combustion turbine size and assumed capacity factor.

Figure 7: Cost of CCS for New Combustion Turbines

| | NETL F-Class, No CCS | NETL F-Class, 90% CCS | NETL H-Class, No CCS | NETL H-Class, 90% CCS | EPA Estimated 90% CCS |
|---|---|---|---|---|---|
| Total As Spent Capital ($/kW) | 1,040 | 2,239 | 1,060 | 2,115 | |
| Total As Spent Capital of CCS ($/kW) | | 949 | | 823 | 1,440 |
| Base Load Rating (MMBtu/h) | 4,623 | 4,623 | 6,147 | 6,147 | 2,000 |
| Net Power Output (MW) | 727 | 645 | 992 | 883 | 279 |
| Derate from CCS (%) | | 11% | | 11% | 11% |
| Gross Efficiency (%) | 54.6% | 51.1% | 56.1% | 52.5% | 51.1% |
| Net Efficiency (%) | 53.6% | 47.6% | 55.1% | 49.0% | 47.6% |
| Increase in Heat Rate from CCS (%) | | 13% | | 12% | 13% |
| Design Capture Rate (tonne/h) | | 255 | | 299 | 97 |
| Fixed Costs ($/MWh) | 3.6 | 7.4 | 3.5 | 6.8 | |
| Increase in Fixed Costs from CCS ($/MWh) | | 2.3 | | 2.1 | 5.0 |
| Variable Costs ($/MWh) | 1.7 | 4.0 | 1.7 | 3.8 | |
| Increase in Variable Costs from CCS ($/MWh) | | 2.3 | | 2.1 | 2.3 |
| LCOE ($/MWh) | 49 | 57 | 49 | 52 | |
| Abatement Costs ($/MWh) | | 6.4 | | 3.5 | 16 |
| Abatement Costs ($/ton) | | 19 | | 11 | 41 |

* Assumptions: 12-year amortization, 7 percent interest rate, $3.69/MMBtu natural gas, $85/tonne tax credit, 75 percent capacity factor, and $10/tonne TS&M costs
* Capital and fixed costs on a pre-derate basis

Figure 8: Abatement Costs for New Combustion Turbines

| Capacity Factor (%) | Base Load Rating (MMBtu/h) | | | |
|---|---|---|---|---|
| | 2,000 MMBtu/h | | 4,623 MMBtu/h | |
| | Abatement Costs ($/ton), 12-year amortization | Abatement Costs ($/ton), 30-year amortization | Abatement Costs ($/ton), 12-year amortization | Abatement Costs ($/ton), 30-year amortization |
| 50% | $84 | $81 | $50 | $57 |
| 60% | $62 | $66 | $34 | $46 |
| 70% | $47 | $56 | $23 | $38 |
| 80% | $36 | $48 | $15 | $33 |

* Assumptions: 7 percent interest rate, $3.69/MMBtu natural gas, $10/tonne TS&M costs, $85/tonne tax credit for 12-year amortization, and $45/tonne tax credit for 30-year amortization.

**Costing Approaches for Existing Natural Gas-fired Combined Cycle EGUs**

To estimate the cost of CCS for existing combined cycle EGUs, the EPA used the NETL report *Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3* (DOE/NETL - 2023/3848, March 17, 2023). The report provides an analysis of CCS retrofit costs that is analogous to the analysis for new combined cycle EGUs, and compares costs for new versus retrofit installation, and is discussed here for reference. The report assesses the capital cost outlay required for the capture process and associated modifications to the existing plant, Cases are developed for NGCC plants retrofitted with commercial, state-of-the-art solvent-based post-combustion carbon capture. A retrofit difficulty factor (RDF) of 1.09 was used to account for the cost premium for design, construction, and tie-in constraints imposed by existing plant layout and operation. This RDF represents the weighted average of the NETL, *Quality Guidelines for Energy System Studies: Carbon Capture Retrofit Studies* (DOE/NETL, Pittsburgh, PA, 2019) recommended account-level retrofit difficulty factors for an NGCC plant retrofit with post combustion capture. The capital costs were estimated by multiplying the RDF by the total plant cost of an equivalent greenfield installation. The retrofit case performance for each turbine type was assumed to be identical to the greenfield capture case performance except for an off-design efficiency penalty applied to the steam turbine due to the throttled steam extraction upstream from the existing plant LP turbine stage resulting in operation at a significantly reduced flow relative to the full design flow. This causes a derate not only based on lower power production from decreased flow to the steam turbine, but also an additional derate due to an efficiency penalty caused by off-design flow to the steam turbine. The efficiency penalty reduces power generation in the steam turbine by about 4-5 MWe, about 2 percent of the steam turbine gross power output or less than 1 percent of net power. The costs of $CO_2$ transport and storage ($10/metric ton) are drawn from NETL, *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies* (DOE/NETL, Pittsburgh, PA, 2019).

The additional capital costs increase the LCOE of the retrofit CCS by an additional $2.2/MWh compared to an installation at a new combined cycle EGU.[7] Assuming the same model plant, a 90 percent-capture retrofit amine-based post combustion CCS system increases the LCOE by $8.6/MWh and has overall $CO_2$ abatement costs of $26/ton ($28/metric ton). Similar to NETL estimates for greenfield CCS projects, costs at a specific plant would be expected to vary somewhat from this estimate, as it does not include site and plant-specific considerations such as seismic conditions, local labor costs, or local environmental regulations. Figure 9 shows the costs of retrofit CCS at different combustion turbine sizes and capacity factors.

[7] These calculations use the NETL F-Class turbine, a service life of 12 years, an interest rate of 7.0 percent, a natural gas price of $3.69/MMBtu, a capacity factor of 75 percent, a transport, storage, and monitoring cost of $10/metric ton, and a 45Q tax credit of $85/metric ton.

Figure 9: Abatement Costs for Retrofit Combustion Turbines

| Capacity Factor (%) | Abatement Costs ($/ton), 12-year amortization | |
|---|---|---|
| | Base Load Rating (MMBtu/h) | |
| | 2,000 MMBtu/h | 4,623 MMBtu/h |
| 50% | 94 | 69 |
| 60% | 70 | 47 |
| 70% | 54 | 32 |
| 80% | 42 | 20 |

* Assumptions: 7 percent interest rate, $3.69/MMBtu natural gas, $10/tonne TS&M costs, $85/tonne tax credit for 12-year amortization, and $45/tonne tax credit for 30-year amortization.

**$CO_2$ Removal Rates**

The NETL Baseline Report makes clear that solvent-based post-combustion $CO_2$ capture systems at NGCC plants can reliably capture at least 90 percent of the $CO_2$ in the flue gas stream. The Report also states that “technology suppliers” and “subject matter experts” state that solvent-based post-combustion $CO_2$ capture technologies are capable of achieving even higher $CO_2$ removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Specifically, the NETL Baseline Report states:

> “Commercial-scale demonstration of solvent-based post-combustion $CO_2$ capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the $CO_2$ in the flue gas stream. [11] [12] Moreover, field-testing of post-combustion $CO_2$ capture technology as well as vendor and industry feedback on projects currently in the planning stages (including FEED projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. [13] [14] [15] [16] Given the breadth of publicly-available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the $CO_2$ in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report. It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS (97 percent for NGCC and 99 percent for PC) study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO2 capture technologies are capable of achieving $CO_2$ removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion.”

> [11] W. P. Greg Kennedy, "Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)," [Online]. Available: https://doi.org/10.2172/1608572. [Accessed 12 September 2022].
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> [12] S. Giannaris, D. Janowczyk, J. Ruffini, K. Hill, B. Jacobs, C. Bruce, Y. F. Feng and W. and Srisang, "SaskPower’s Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability," 15th International Conference on Greenhouse Gas Control Technologies, Abu Dhabi, 2021.
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> [13] National Carbon Capture Center, "Topical Report Budget Period Six," October 2020. [Online]. Available: https://www.nationalcarboncapturecenter.com/wpcontent/uploads/2022/08/NCCC-BP6-Report-DE-FE0022596.pdf. [Accessed 12 September 2022].
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> [14] National Carbon Capture Center, "Topical Report Budget Period 5," September 2020. [Online]. Available: https://www.nationalcarboncapturecenter.com/wpcontent/uploads/2021/07/NCCC-BP5-Report-DE-FE0022596.pdf. [Accessed 12 September 2022].
>
> [15] K. C. OBrien, Y. Lu, J. Dietsch, Z. (. Zhang, C. Maas, T. Thomas, K. Iwakura, M. Thomas, A. Donovan, P. M. Guletsky and R. Meyer, "Full-scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology," 2022.

[Online]. Available: https://doi.org/10.2172/1879443. [Accessed 12 September 2022].

[16] International CCS Knowledge Center, "The Shand CCS Feasibility Study - Public Record," 2018, November. [Online]. Available: https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf. [Accessed 12 September 2022].

National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants. Volume 1: Bituminous Coal and Natural Gas to Electricity" (October 14, 2022) at 29, 734-35. https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

**Potential advancements in $CO_2$ Capture**

The DOE, the utility industry, and other organizations are developing additional carbon capture technologies that have the potential to reduce the costs and auxiliary energy requirements of CCS. These technology advances would reduce the future costs of CCS. For example, one approach that can increase the concentration of $CO_2$ in the combustion turbine exhaust is the use of exhaust gas recirculation (EGR). By increasing the $CO_2$ concentration, the size and costs of the capture system can be decreased. These advanced CCS technologies, by making the process itself more efficient, offer opportunities for cost reduction for both CCS retrofits and new build CCS applied to combustion turbines. This section describes carbon capture technologies and potential advances that will reduce the future costs of CCS.

Currently available post-combustion amine-based carbon capture systems require that the flue gas be cooled prior to entering the carbon capture equipment. This holds true for the exhaust from a combustion turbine. The most energy efficient way to do this is to use a heat recovery steam generator (HSRG)—which is an integral component of a combined cycle turbine system—to generate additional useful electric output. Because simple cycle combustion turbines do not incorporate a HRSG, the Agency is limiting consideration of the use of CCS to only combined cycle combustion turbine EGUs for both its standards for new combustion turbines and its emission guidelines for existing combustion turbines. This document describes some of the available technologies to capture CO2 as well as their application to combustion turbines. The National Carbon Capture Center includes a more comprehensive list of carbon management technologies.[8]

<u>Exhaust (Flue) Gas Recirculation</u>

Flue gas composition varies based on power plant technology. For example, due to the carbon content of the different fuels, flue gas from a natural gas-fired combustion turbine generally has a lower concentration of $CO_2$ and a higher concentration of $O_2$ than the exhaust from a coal-fired power plant.[9] Flue gas from a natural gas-fired combustion turbine also has a higher flow rate and temperature than the flue gas from a coal plant. These factors make carbon capture more expensive and challenging for combustion turbines. It is easier to capture carbon from flue gas with a higher concentration of $CO_2$, and capturing $CO_2$ from more dilute gas streams requires larger equipment, more energy, and a larger

[8] Additional information is available at: https://www.nationalcarboncapturecenter.com/

[9] DOE NETL (2022). *Cost And Performance Baseline For Fossil Energy Plants Volume 1: Bituminous Coal And Natural Gas To Electricity*. DOE/NETL-2023/4320. Accessed at https://www.osti.gov/servlets/purl/1893822.

investment.[10] The higher oxygen concentration in the combustion turbine flue gas can also contributes to increased carbon capture costs due to oxidation of the amine.[11]

Exhaust gas recirculation (EGR), also referred to as flue gas recirculation (FGR), is a method to divert some of the exhaust gas back into the inlet stream of the combustion turbine. Doing so increases the $CO_2$ concentration in the inlet stream, producing favorable conditions for efficient carbon capture and storage (CCS). EGR helps to reduce the impact that excess $O_2$ can have on some processes, such as oxidation on amine-based solvents. One study found that approximately 30 to 50percent of exhaust gas mass flow is typically recirculated back into the inlet gas when employing EGR. Depending on the ratio of exhaust gas recirculated, the $CO_2$ concentration can be nearly doubled in the flue gas at the exit of the combustion turbine. Additionally, the study found that exhaust gas recirculation can increase efficiency of a combined cycle combustion turbine with CCS by up to 2.1 percent.[12] Another study found that an EGR ratio of 35 percent is the maximum because it allows the concentration of $O_2$ at the combustor inlet to remain at favorable conditions. Compared to a combustion turbine without EGR, a combustion turbine with a 35 percent ratio causes a 0.7 percent reduction in heat rate and a 0.3 percent reduction in electric output of the system while increasing the net efficiency from 47.4 to 48.6 percent. Figure 1 shows the costs of a combined cycle plant with a 90 percent $CO_2$ capture ratio and a 35 percent EGR ratio compared to a combined cycle plant with a 0% EGR ratio.[13]

Figure 9: Relative Costs of CC with 0 and 35 Percent EGR Ratio

| **EGR Ratio** | **LCOE Cost ($/MWh)** | **Decrease in CC Cost Relative to 0% EGR** | **Cost of $CO_2$ Abatement ($/tonne)** | **Decrease in $CO_2$ Abatement Cost Relative to 0% EGR** | **Capital Cost ($/MWh)** | **Decrease in Capital Cost Relative to 0% EGR** |
|---|---|---|---|---|---|---|
| 0% | 80.5 | - | 75.9 | - | 21.8 | - |
| 35% | 77.8 | 3.4% | 67.7 | 11% | 20.4 | 6.4% |

EGR can also impact the $NO_X$ emissions from a combined cycle combustion turbine power plant by reducing the $O_2$ concentration in the inlet gas, leading to lower maximum temperatures and reduced $NO_X$ formation during combustion.[14] One study found that $NO_X$ emissions decrease by more than 50 percent with a 35 percent increase in EGR.[15] One company offers EGR through its Semi-Closed Cycle (SCC) technology. The SCC increases $CO_2$ concentration in the exhaust up to 25 percent, which decreases the exhaust volume. The reduction in exhaust volume allows carbon capture to be viable using smaller, less expensive systems.[16]

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[10] MIT Climate (2021). *How efficient is carbon capture and storage?*. Accessed at https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage.

[11] Al Hashmi, A.B., Mohamed, A.A.A. and Dadach, Z.E. (2018). *Process Simulation of a 620 Mw-Natural Gas Combined Cycle Power Plant with Optimum Flue Gas Recirculation.* Accessed at https://www.scirp.org/pdf/ojee_2018051615523534.pdf.

[12] Turbomachinery International (TMI) (2011). *Impact of exhaust gas recirculation on gas turbines.* Accessed at https://www.turbomachinerymag.com/view/impact-of-exhaust-gas-recirculation-on-gas-turbines.

[13] Vaccarelli, M., Carapellucci, R., Giordano, L. (2014). *Energy and Economic Analysis of the CO2 Capture from Flue Gas of Combined Cycle Power Plants*. Accessed at https://doi.org/10.1016/j.egypro.2014.01.122.

[14] Sher, E. (1998). *Handbook of Air Pollution From Internal Combustion Engines.* Pollutant Formation and Control.

[15] Elkady A., Evulet A., Brand A., Ursin T.P., Lynghjem A. (2009) *Application of Exhaust Gas Recirculation in a DLN F-Class Combustion System for Post combustion Carbon Capture*. Journal of Engineering for Gas Turbines and Power. https://doi.org/10.1115/1.2982158

[16] CarbonPoint Solutions (2022). *Carbon Capture Applications*. Accessed at https://www.carbonpoint.com/carbon-capture-applications.

Selective exhaust gas recirculation (S-EGR) is a variant of EGR that uses a membrane system that selectively separates the $CO_2$ in the flue gas. The $CO_2$ enters the combustion air sweep stream, which flows into the compressor inlet, whereas the $CO_2$-depleted flue gas exits to the atmosphere. Since primarily $CO_2$ permeates the membrane, a higher $CO_2$ content can be achieved in the flue gas with S-EGR than with EGR due to the absence of nitrogen in the combustion air.[17]

Amine-Based Capture Systems

Amine-based solvent $CO_2$ capture systems work by scrubbing $CO_2$ from the flue gas using the solvent. The flue gas initially enters an absorption column, where the $CO_2$ is captured by the amine solvent. The solvent is then sent to a desorber column, or regenerator, in which the solvent is heated to release the $CO_2$. The regenerated solvent returns to the absorption column after it is cooled. The regeneration process requires a large amount of heat and electricity to operate the capture system which reduces both the gross and net efficiency of the power plant.

There are two broad approaches to providing the necessary steam and power: integrated and non-integrated (*i.e.*, "side car") approaches.[18] An integrated system sources all the carbon capture energy needs from the existing power plant. This means that electricity is supplied by increasing auxiliary power output and steam is extracted from the existing steam cycle for use in the capture system.[19] Alternatively, the steam and electricity demand of a capture system can be provided through a non-integrated approach. In this approach, a separate auxiliary power plant is constructed for the sole purpose of providing steam and electricity to the capture system. The separate power plant could be a natural gas-fired combustion turbine combined heat and power (CHP) unit in either a simple cycle or combined cycle configuration to provide energy for a capture system of an existing coal plant.[20] Depending on the configuration of the CHP unit, it is possible that the overall electric output of the facility could be increased.

Solid Sorbents

Solid sorbents can be used to capture $CO_2$ through chemical adsorption, physical adsorption, or a combination of the two effects. Solid sorbents have shown a range of potential benefits compared to amine-based solvents, including lower energy requirements, better adsorption capacity, lower toxicity, lower corrosivity, and lower volatility.[21, 22] Solid sorbents are not widely deployed for $CO_2$ capture from EGUs although the technology has a proven record. One notable example of solid sorbent $CO_2$ capture is DOE supported Valero Energy's Port Arthur refinery project, which was retrofit with a CCS system that uses sorbents in a vacuum swing adsorption (VSA) process to remove $CO_2$ from steam methane

[17] Diego, M.E., et al. (2017). *Making gas-CCS a commercial reality: The challenges of scaling up*. Accessed at https://doi.org/10.1002/ghg.1695.
[18] National Energy Technology Laboratory (NETL) (2016). *Elimination the Derate of Carbon Capture Retrofits*. May 31, 2016. Accessed at https://netl.doe.gov/projects/files/EliminatingDerateCarbonCaptureRetrofits_040119.pdf.
[19] NETL (2016). *Elimination the Derate of Carbon Capture Retrofits*. May 31, 2016. Accessed at. https://www.netl.doe.gov/projects/files/EliminatingDerateCarbonCaptureRetrofits_040119.pdf.
[20] National Energy Technology Laboratory (NETL) (2016). *Elimination the Derate of Carbon Capture Retrofits*. May 31, 2016. Accessed at https://usepa.sharepoint.com/sites/RTI/Shared%20Documents/General/CCUS/Eliminating%20Derate%20Carbon%20Capture%20Retrofit%20DOE%20NETL-2016%201796,%20May%202016.pdf?CT=1673373815888&OR=ItemsView.
[21] Khraisheh, M., Almomani, F., Walker, G. (2020). *Solid Sorbents as a Retrofit Technology for $CO_2$ Removal from Natural Gas Under High Pressure and Temperature Conditions.* Scientific Reports. https://doi.org/10.1038/s41598-019-57151-x.
[22] Wang, D., Sentorun-Shalaby, C., Ma, X., Song, C. (2011). *High-Capacity and Low-Cost Carbon-Based "Molecular Basket" Sorbent for $CO_2$ Capture from Flue Gas*. Energy Fuels. https://doi.org/10.1021/ef101364c.

reforming syngas and has successfully removed 4 million metric tons (MMT) after 5 years of operation.[23, 24]

While solid sorbents for $CO_2$ capture at EGUs are largely still at the lab or bench scale, there has been promising results with important implications for these technologies' future.[25] One company has developed an advanced solid sorbent-based $CO_2$ capture process that may potentially achieve the DOE's Carbon Capture Program's goal of greater than a 90 percent capture rate at a cost of less than $40/ton $CO_2$ by 2025. The advanced solid sorbent is believed to outperform monoethanolamine (MEA) solvents for the steam demand, energy demand, cooling water demand, and capital costs as it relates $CO_2$ capture although it would require a higher electricity demand.[26] Another pilot campaign has successfully demonstrated an advanced solid sorbent technology to operate at a capture rate of greater than 90 percent and $CO_2$ purity of greater than 95 percent with little to no process emissions and a lower capture cost than most state-of-the-art amine technologies. The pilot plant was a 62.5 $MW_{th}$ biomass-fired power plant in Simmering, Austria, and the pilot campaign ran for 900 hours.[27]

Membranes

Membrane-based carbon capture uses permeable or semi-permeable materials that allow for the selective transport/separation of $CO_2$. Membrane systems are well suited to applications where the pressure of the gas treated is relatively high, but are also applicable to atmospheric conditions. Membrane-based capture systems are an attractive option in low carbon emission technologies that can operate in continuous systems but are estimated to be less cost-competitive at larger scales (*i.e.*, greater than 100 tons of flue gas per day). Membrane technologies typically have a lower capital cost, lower operating cost, adaptability, and simpler design than alternative carbon capture technologies. Challenges still exist in adopting membrane technologies for post-combustion capture. The low $CO_2$ volumetric fraction in the flue gas results in less $CO_2$ being driven through the membrane.[28, 29]

While not widely adopted for post-combustion $CO_2$ capture, membrane technology is expected to increase performance as membrane materials advance and are integrated into more efficient systems. Examples of improved membrane materials/processes include zeolites, carbon molecular sieves, metal oxide frameworks, graphenes, and facilitated transport membranes, with record permeances of 10,000 gas permeation units (GPU) having been recorded for graphene membranes. In general, these advanced

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[23] DOE (2017). *DOE-Supported $CO_2$-Capture Project Hits Major Milestone: 4 Million Metric Tons*. Accessed at https://www.energy.gov/fecm/articles/doe-supported-co2-capture-project-hits-major-milestone-4-million-metric-tons.

[24] Massachusetts Institute of Technology (MIT) (2016). *Port Arthur Fact Sheet: Carbon Dioxide Capture and Storage Project*. Accessed at https://sequestration.mit.edu/tools/projects/port_arthur.html.

[25] National Petroleum Council (2021). *A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage – Appendix F.* Accessed at https://dualchallenge.npc.org/downloads.php.

[26] Nelson, T. O., Kataria, A., Mobley, P., Soukri, M., Tanthana, J. (2016). *RTI's Solid Sorbent-Based $CO_2$ Capture Process: Technical and Economic Lessons Learned for Application in Coal-fired, NGCC, and Cement Plants.* Energy Procedia 114 (2017) 2506 – 2524. doi:10.1016/j.egypro.2017.03.1409.

[27] Van Paasen, S., Infantino, M., Yao, J., Leenders, S., van de Graaf, J. (2021). *Development of the Solid Sorbent Technology for Post Combustion $CO_2$ Capture Towards Commercial Prototype.* Proceedings of the 15th Greenhouse Gas Control Technologies Conference 15-18 March 2021. https://dx.doi.org/10.2139/ssrn.3820787.

[28] Ji, G., Zhao, M. (2017). *Membrane Separation Technology in Carbon Capture*. DOI: 10.5772/65723.

[29] Zanco, S. E, Pérez Calvo, J., Gasós, A, Cordiano, B., Becattini, V., Mazzotti, M. (2021). *Postcombustion $CO_2$ Capture: A Comparative Techno-Economic Assessment of Three Technologies Using a Solvent, an Adsorbent, and a Membrane.* https://doi.org/10.1021/acsengineeringau.1c00002?urlappend=%3Fref%3DPDF&jav=VoR&rel=cite-as.

systems are trending toward nanostructured membranes and chemically reactive membranes that show noticeable improvements in carbon capture.[30]

Chilled Ammonia, PSA, and Cryogenic

Chilled ammonia carbon capture uses an aqueous solution of ammonia in chilled conditions, mainly between 0 and 10 degrees Celsius (°C). Flue gas from the process is cooled through direct contact cooling and then sent to an absorber, where more than 90 percent of the $CO_2$ from the flue gas can be captured. The resulting stream contains a significant amount of ammonia. An ammonia absorption/desorption system is used to purify the stream. The system creates a gas stream of $CO_2$, which is purified and compressed for storage and transport. The EPA is not aware of any chilled ammonia carbon capture systems being considered for use in new or existing EGUs.[31]

Pressure swing adsorption (PSA) is a process that separates gases in a gas mixture. The targeted gas molecules, such as $CO_2$, are bound to an adsorbent material. The material is then depressurized and the target gas is released into another vessel or pipe. PSA is commonly used for processes with high $CO_2$ concentrations such as steam methane reforming and coal gasification.[32]

Cryogenic carbon capture (CCC) is a process that cools $CO_2$-rich gases to negative 140 °C where the $CO_2$ desublimates, separates the desublimated solids from the light gases, and warms the $CO_2$ and light gas streams back to their initial temperatures. The process delivers liquid $CO_2$ at a pressure of above 125 bar and at an ambient temperature. All components of the flue gas end up separated in the process.[33]

Improved Solvents

Improvements in second generation solvents and next generation solvents are intended to be direct substitutes for earlier amine-solvents. Several research efforts are taking place to make sorbents cheaper and more efficient at carbon capture, which will increase their economic competitiveness.[34] Improvement in solvents is occurring through use of different amines, addition of additives, a combination of different amines and additives, or separate solvent categories altogether.[35, 36]

One alternative solvent for carbon capture use is methanol. Methanol is used as a physical solvent in a process known as Rectisol®. The Rectisol process occurs at low temperatures, as low as negative 59.5 to

[30] Favre, E. (2022). *Membrane Separation Processes and Post-Combustion Carbon Capture: State of the Art and Prospects*. Membranes 2022, 12, 884. https://doi.org/10.3390/membranes12090884.
[31] Augustsson, et al. (2016). *Chilled Ammonia Process Scale-up and Lessons Learned*. Accessed at https://az659834.vo.msecnd.net/eventsairwesteuprod/production-ieaghg-public/82023fd0a38e483682a56f901496c601.
[32] PG&E (2018). *Adsorption Technical Analysis*. Accessed at https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/PressureSwingAdsorption_TechnicalAnalysis.pdf.
[33] Baxter, et al. (2021). *Cryogenic Carbon Capture (CCC) Status Report*. Accessed at https://www.osti.gov/servlets/purl/1781602.
[34] DOE. *Carbon Capture, Transport, & Storage. Supply Chain Deep Dive Assessment*. February 24, 2022. Accessed at *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf*.
[35] AECOM (2022). *Next Generation Carbon Capture Technology.* Technology Review. May 24, 2022. Accessed at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1079540/aecom-next-gen-carbon-capture-technology-technology-review-annex-1.pdf.
[36] DOE. *Carbon Capture, Transport, & Storage. Supply Chain Deep Dive Assessment*. February 24, 2022. Accessed at *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf*.

negative 73.3 °C. The process has demonstrated a high capture efficiency for both $CO_2$ and hydrogen sulfide ($H_2S$) compared to other solvents.[37]

Another amine-based solvent alternative is ionic liquids (ILs), which are ionic salts with a melting point below 100 °C. ILs may be a favorable alternative to amine-based solvents due lower volatility, low corrosivity, nonflammability, and high $CO_2$ solubility. Compared to traditional amine-based solvents, ILs are expected to have fewer solvent losses resulting in lower costs.[38] Currently, ILs have shown success at the lab scale but are yet to be demonstrated at the pilot scale.[39]

Aminosilicone is another solvent being developed with significant potential for $CO_2$ capture and is known to be a water-lean solvent. Modeling estimates predict that the carbon capture process will be less expensive than that of monoethanolamine (MEA) solvents, with first-year costs of aminosilicone and MEA carbon capture estimated to be \$46.04/ton $CO_2$ and \$60.25/ton $CO_2$, respectively. The lower cost is due to a lower necessary solvent flow rate, which reduces equipment sizes. Additionally, the high thermal stability of aminosilicone is expected to allow desorption at higher temperatures and pressures, reducing needs for compressors. Lastly, the low vapor pressure allows desorption to occur in a continuous-stirred tank reactor as opposed to a more expensive packed column.[40] General Electric is piloting this technology as part of a DOE-funded project to evaluate the performance at a 10 MWe plant.[41]

There are several other improved solvent iterations that are unique, and often proprietary, that are being tested in the lab and/or at pilot scales. The DOE has funded many of these projects and successful results have important implications for commercial adoption in the future. While the solvents and processes can be widely variable, the solvents largely fall into two categories: water-lean solvents and multiphase solvents. Water-lean solvents reduce energy requirements for regeneration and are typically nonvolatile. Additionally, water-lean solvents can potentially exist on the same infrastructure as aqueous amine solvents while showing improved results. Multiphase solvents form more than one liquid phase or form a solid/liquid phase leading to capture process improvements. Notably, this allows for a high-density $CO_2$ phase to form, reducing the quantity of solvent needing regeneration, and it can lead to reduced energy requirements and improved performance.[42] $CO_2$-binding organic liquids ($CO_2$BOLs) are a class of water-lean solvents that is comprised of a single component instead of mixtures of different compounds. $CO_2$BOLs do not require co-solvents unlike most amine-based carbon capture solvents, which make it simple to handle properties like solvent boiling point with a single dataset.[43]

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[37] Borhan, N., & Wang, M. (2019). *Role of solvents in $CO_2$ capture processes: the review of selection and design methods.* Renewable and Sustainable Energy Reviews, 114. ISSN 1364-0321. https://doi.org/10.1016/j.rser.2019.109299.
[38] Ramdin, M., de Loos, T. W., Vlugt, T. J. H. (2012). *State-of-the-Art of $CO_2$ Capture with Ionic Liquids*. Ind. Eng. Chem. Res. 2012, 51, 8149-8177. Accessed at https://pubs.acs.org/doi/pdf/10.1021/ie3003705.
[39] National Petroleum Council (2021). *A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage – Appendix F.* Accessed at https://dualchallenge.npc.org/downloads.php.
[40] Kehmna, M., McDuffie, D. (2014). *Pilot-Scale Silicone Process for Low-Cost Carbon Dioxide Capture*. Accessed at https://www.osti.gov/servlets/purl/1134751.
[41] National Petroleum Council (2021). *A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage – Appendix F.* Accessed at https://dualchallenge.npc.org/downloads.php.
[42] National Petroleum Council (2021). *A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage – Appendix F.* Accessed at https://dualchallenge.npc.org/downloads.php.
[43] Pacific Northwest National Laboratory (2020). *CO2BOL Solvents for Cheaper Carbon Capture and Sequestration, Pre- and Post-Combustion*. Accessed at https://www.pnnl.GOV/available-technologies/co2bol-solvents-cheaper-carbon-capture-and-sequestration-pre-and-post.

The DOE's Pacific Northwest National Laboratory (PNNL) is developing a carbon capture system that seeks to convert the captured $CO_2$ into methanol at a capture cost of $39 per metric ton of $CO_2$.[44] The carbon capture process can occur pre- or post-combustion in power plants and other facilities where flue gas is emitted. PNNL is using a water-lean solvent, known as EEMPA, and plans to analyze the solvent in testing facilities at the National Carbon Capture Center in Shelby County, Alabama.[45]

Scientists at PNNL have created a new carbon capture process that is potentially less expensive than other carbon capture systems because it operates with 2 percent water as opposed to as much as 70 percent water with other carbon capture technologies. By removing the water from the system, the carbon capture process becomes much cheaper.[46]

Carbonate Fuel Cells

Carbonate fuel cells are configured for emissions capture through a process where the flue gas from an EGU is routed through the carbonate fuel cell that concentrates the $CO_2$ as a side reaction during the electric generation process in the fuel cell. The concentration of $CO_2$ allows for carbon capture and removal from the system. Currently, *FuelCell Energy* has carbonate fuel cells designed at 1.4 MW and 2.8 MW.[47] Similar to using an auxiliary combustion turbine to power the CCS process, carbonate fuel cells increase the power output.

Chemical Looping

Chemical looping systems utilize metal particles known as $O_2$ carriers as a medium to transport $O_2$ between air and fuel reactors with the goal of avoiding nitrogen being present in combustion exhaust. The oxidized $O_2$ carrier is sent to the fuel reactor to oxidize the fuel. The reduced $O_2$ carrier then moves into the air reactor to oxidize itself via the air stream and then loops back into the fuel reactor. A continuous chemical combustion loop takes place between pure $O_2$ and fuel, thus making the flue gas free of nitrogen. This would easily allow the condensing of steam and storage of $CO_2$ away from the atmosphere.[48] One study compared natural gas combined cycle power plants using MEA solvents to chemical looping technology. The chemical looping system produced an efficiency, a cost of electricity, and a cost of $CO_2$ capture of 44.3 percent, $75.8/MWh, and $59.2/ton $CO_2$, respectively. The MEA system produced values of 43.8 percent, $82/MWh, and $76.2/ton $CO_2$, respectively. The chemical looping system also produced a higher carbon capture efficiency of 99.93 percent compared to the 95.3 percent of the MEA system.[49]

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[44] Pacific Northwest National Laboratory (2023). *Scientists Unveil Least Costly Carbon Capture System to Date*. Accessed at https://www.pnnl.gov/news-media/scientists-unveil-least-costly-carbon-capture-system-date. The technology reportedly requires 17 percent less energy than commercial alternatives, which translates to a 19 percent reduction in capture cost.
[45] Pacific Northwest National Laboratory (2021). *Cheaper Carbon Capture Is on the Way*. Accessed at https://www.pnnl.gov/news-media/cheaper-carbon-capture-way.
[46] https://cleantechnica.com/2023/01/26/carbon-capture-for-less-than-40-a-ton-its-possible-says-pnnl/ ; https://www.pnnl.gov/news-media/scientists-unveil-least-costly-carbon-capture-system-date ; https://www.pnnl.gov/news-media/cheaper-carbon-capture-way
[47] FuelCell Energy, Inc. (2018). *SureSource Capture*. *https://www.fuelcellenergy.com/recovery-2/suresource-capture/*.
[48] Siddig Abuelgasim, Wenju Wang, Atif Abdalazeez (2021). *A brief review for chemical looping combustion as a promising $CO_2$ capture technology: Fundamentals and progress*. Accessed at https://doi.org/10.1016/j.scitotenv.2020.142892.
[49] Dong-Hoon Oh, Chang-Ha Lee, Jae-Cheol Lee (2021). *Performance and Cost Analysis of Natural Gas Combined Cycle Plants with Chemical Looping Combustion*. Accessed at https://pubs.acs.org/doi/10.1021/acsomega.1c02695?ref=pdf.

Oxygen Combustion

Oxygen combustion (*i.e.*, oxy-combustion, oxy-firing, or oxy-fuel) is the use of a mixture of $O_2$ (or oxygen-enriched air) in place of ambient air for combustion. For an EGU, the source of purified $O_2$ is typically supplied by an air separation unit (ASU). The most common ASU is a cryogenic process that has a significant energy requirement. However, alternative $O_2$ separation methods are being researched for possible commercial-scale development. These alternative methods include ion transport membranes (ITM), ceramic autothermal recovery, $O_2$ transport membranes, and chemical looping.[50] The benefits offered by this technology are its potential for higher efficiencies, reduced overall costs, reduced criteria and hazardous air pollutants, and advantages for $CO_2$ emissions control. Because the $O_2$ combustion produces a flue gas that contains primarily $CO_2$ and water vapor, minimal post-combustion cleanup (if necessary) is required prior to compression, transportation, and injection for use in geological storage, enhanced oil or gas recovery, or some other use. There are multiple pilot scale projects that have demonstrated the technology.[51]

*The NET Power Cycle*

The NET Power Cycle[52] is a proprietary process for producing electricity that combusts a fuel with purified $O_2$ and that uses supercritical $CO_2$ as the working fluid. This "oxy-fuel" design feature precludes formation of $NO_X$ compounds inherent in traditional air-fuel technologies. However, the flame temperature of natural gas burned with pure $O_2$ is greater than 2,800 °C (5,000 °F), which is above the melting point of conventional materials used to fabricate combustor components. To prevent overheating, the NET Power Cycle uses recycled $CO_2$ as a diluent to control temperatures within the combustor. Like an air-fired combined cycle EGU, the NET Power Cycle incorporates a heat exchanger to capture the heat in combustion turbine exhaust, but instead of transferring the heat to a steam cycle, the NET Power Cycle transfers the heat to the high-pressure $CO_2$ stream that supplies diluent to the combustor. This cycle is designed to achieve thermal efficiencies of 59 percent.[53] Potential advantages of this cycle are that it emits no $NO_X$ and produces a stream of high-purity $CO_2$[54] that can be delivered by pipeline to a storage or sequestration site without extensive processing.

[50] The energy required to operate a cryogenic ASU offsets at least a portion of the emissions and cost savings. Newer ASU designs offer the potential to improve the overall environmental benefits of oxygen combustion. If large quantities of hydrogen are produced from electrolysis process, by-product oxygen will also be produced on a large scale.
[51] See https://netl.doe.gov/node/7477 and https://sequestration.mit.edu/tools/projects/vattenfall_oxyfuel.html/
[52] https://netpower.com/technology/. The Net Power Cycle was formerly referred to as the Allam-Fetvedt cycle. See also https://www.eenews.net/articles/worlds-first-zero-emission-gas-plant-announced-in-texas/
[53] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11% more efficient, all $CO_2$ captured. *Energy Post*. *https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/*.
[54] This allows for capture of nearly 100% of the $CO_2$ emissions.

**Existing and Planned CCS Projects as well as FEED Studies for Combustion Turbines**

This section describes existing and planned CCS projects on new and existing combined cycle combustion turbines and Front-End Engineering Design (FEED) studies for potential future projects.

Existing and Planned CCS Projects on Natural Gas-Fired Combined Cycle EGUs

While most demonstrations of CCS have been for applications other than combustion turbines, CCS has been successfully applied to an existing combined cycle EGU and several other projects are in development. Examples of the use of CCS on combined cycle EGUs include the Bellingham Energy Center in south central Massachusetts and the proposed Peterhead Power Station in Scotland. The Bellingham plant used Fluor's Econamine FG Plus[SM] capture system and demonstrated the commercial viability of carbon capture on a combined cycle combustion turbine EGU using first-generation technology. The 40-MW slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the $CO_2$ in the slipstream for use in the food industry.[55] In Scotland, the proposed 900-MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. It is anticipated that the power plant will be operational by the end of the decade and will have the potential to capture 90 percent of the $CO_2$ emitting from the combined cycle facility and sequester up to 1.5 million tonnes of $CO_2$ annually. A storage site being developed 62 miles off the Scottish North Sea coast might serve as a destination for the captured $CO_2$.[56] Moreover, an 1,800-MW natural gas combined cycle EGU project has been announced that will be constructed in West Virginia and will utilize CCS. The power plant is anticipated to begin operation later this decade and its feasibility was partially credited to the expanded Internal Revenue Code (IRC) section 45Q tax credit for sequestered $CO_2$ provided through the Inflation Reduction Act (IRA).[57]

In addition, there are several planned projects using the NET Power Cycle.[58] The NET Power Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen and uses supercritical $CO_2$ as the working fluid instead of water/steam. This cycle is designed to achieve thermal efficiencies of up to 59 percent.[59] Potential advantages of this cycle are that it emits no $NO_X$ and produces a stream of high-purity $CO_2$[60] that can be delivered by pipeline to a storage or sequestration site without extensive processing. A 50-MW (thermal) test facility in La Porte, Texas, was completed in 2018 and was synchronized to the grid in 2021. There are several announced commercial projects proposing to use the NET Power Cycle. These include the 280-MW Broadwing Clean Energy Complex in Illinois, the 280-MW Coyote Clean Power Project on the Southern Ute Indian Reservation in Colorado, a 300-MW project located near Occidental's Permian Basin operations close to Odessa, Texas, and several international projects. Commercial operation of the facility near Odessa, Texas, is expected in 2026.

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[55] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Accessed at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.
[56] Buli, N. (2021, May 10). SSE, Equinor plan new gas power plant with carbon capture in Scotland. *Reuters*. Retrieved October 14, 2021, https://www.reuters.com/business/sustainable-business/sse-equinor-plan-new-gas-power-plant-with-carbon-capture-scotland-2021-05-11/.
[57] Competitive Power Ventures (2022). *Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia.* Press Release. September 16, 2022. Accessed at https://www.cpv.com/2022/09/16/multi-billion-dollar-combined cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.
[58] *https://netpower.com/technology/*. The NET Power Cycle was formerly referred to as the Allam-Fetvedt cycle.
[59] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11 percent more efficient, all $CO_2$ captured. *Energy Post*. https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.
[60] This allows for capture of over 97 percent of the $CO_2$ emissions. *www.netpower.com*

DOE awards

The DOE awarded $45 million in funding for 12 carbon capture projects to "advance point-source carbon capture and storage technologies that can capture at least 95% of carbon dioxide." Eight of the 12 projects will address carbon capture at natural gas-fired combined cycle combustion turbine power plants, and three of those will involve retrofits of existing NGCC units. The eight combined projects include:

- **James M Barry "Retrofittable advanced combined cycle integration for flexible decarbonized generation" FEED study**. This GE-led FEED study is based on combined cycle plants operating at Southern Company subsidiary Alabama Power's James M. Barry power plant. The Barry site has two 2-on-1 combined cycle combustion turbines in operation and will receive $5,771,670 in Federal funding following successful completion of the award negotiation phase. The funding has a goal of supporting commercial deployment by 2030. GE Gas Power, Southern Company, Linde, BASF, and Kiewit will work to develop a detailed plan for integrating Linde's Gen 2 amine-based carbon capture process, which is based on BASF OASE blue technology. The project will also include gas and steam turbine equipment enhancements to improve the carbon capture process with a goal of reducing the impact of the carbon capture process on the power plant's output, performance, and equipment costs.

- **Deer Park Energy Center NGCC carbon capture system FEED study.** The Calpine Texas CCS Holdings, LLC project team will conduct a FEED study on a modular, commercial-scale, 5 million tonnes net $CO_2$ per year, second-generation CCS system, capturing 95 percent of total $CO_2$ emissions from an NGCC power plant at Calpine's Deer Park carbon capture facility. The project will use Shell's Cansolv capture technology. In October 2021, the DOE awarded grants to fund these two engineering studies in the respective amounts of $5,811,210 and $4,791,966.[61]
- **FEED for a $CO_2$ capture system at Calpine's Delta Energy Center.** ION Clean Energy plans to perform a FEED study for a CCS system to be retrofitted onto Calpine's Delta Energy Center (DEC), an existing 857-MW NGCC power plant located in Pittsburg, California. This will utilize ION's ICE-21 solvent, a proprietary solvent and process that captures more than 90 percent of $CO_2$ from power plant emissions at less than $50/ton.[62] The project is touted to take full advantage of the solvent benefits, which include a smaller physical plant, reduced energy requirements, less solvent degradation, lower emissions, and lower capital costs relative to systems built with commercial benchmark solvents. The goal is to capture 95 percent of DEC's $CO_2$ emissions for geologic storage in the nearby Sacramento Basin. The project aims to demonstrate the declining costs of post-combustion carbon capture and further advance the deployment of CCS technology.
- **Plastic additive, sorbent-coated, thermally-integrated contactor for $CO_2$ capture (PLASTIC4CO2).** A project team led by GE will develop a design for a plastic additive contactor for NGCC flue gas. The team's key objective is to demonstrate an integrated system of plastic additive contactor and metal/covalent organic framework sorbents to capture 95 percent of $CO_2$ from flue gas.

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[61] https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial
[62] https://ioncleanenergy.com/our-technology/

- **Highly efficient regeneration module for carbon capture systems in NGCC applications.** SRI International aims to design, fabricate, and test a highly efficient regeneration module capable of providing an ultra-lean absorption solution that is required for capturing $CO_2$ from dilute sources at 95 percent or better efficiency. By integrating this advanced regenerator module with SRI's Mixed Salt Process absorption modules, SRI expects to demonstrate significant progress toward a 20 percent reduction in cost of capture versus a reference NGCC plant with carbon capture.
- **Bench-scale test of a PEI-monolith $CO_2$ capture process for NGCC point sources.** The CORMETECH, Inc project team plans to further develop, optimize, and bench-scale test an integrated process technology for point source capture of $CO_2$ from NGCC plant flue gas. The process flows NGCC flue gas over a monolithic amine contactor to capture the $CO_2$, followed by steam-mediated thermal desorption and $CO_2$ collection. This process occurs in a multi-bed cyclic process unit but without the need for vacuum, which enhances scalability to large NGCC plants.
- **A new thermal swing adsorption process for post-combustion carbon capture from natural gas plants.** TDA Research, Inc and its project partners aim to fabricate and test a transformational post-combustion capture process. TDA will work with Membrane Technology Research (MTR) to fabricate the engineered sorbent structures and make modules. MTR will fabricate the sorbent sheets/laminates, which will then be integrated with a microwave heater. The resulting module will be evaluated at TDA using simulated NGCC flue gas. These tests seek to demonstrate rapid cycling of the module between adsorption and desorption conditions targeting full cycle times of less than 30 minutes while meeting the DOE's targets (95 percent capture with 95 percent $CO_2$ purity).
- **Dual-loop solution-based CCS for net negative $CO_2$ emissions with lower cost.** A project team led by the University of Kentucky Research Foundation plans to address technical challenges arising from the low $CO_2$ (~4 vol%) and high oxygen (~12 vol%) concentrations in NGCC flue gas by employing a dual-loop solution process to lower the capital cost by 50 percent and offset the operating cost with negative $CO_2$ emissions and hydrogen production.

Additional DOE-supported NGCC projects that employ $CO_2$ capture by absorption with amine solvents via retrofits to existing units.

- A comprehensive FEED Study by Bechtel National for Retrofitting a 2x1 Natural Gas-Fired Gas Turbine Combined Cycle Power Plant for Carbon Capture Storage/Utilization. The Panda Sherman study evaluates a process employing a generic monoethanolamine (MEA) solvent applicable to a 740.6-MW (gross) Siemens "Flex Plant" generator. The disposition of $CO_2$ by either enhanced oil recovery or sequestration in an adjacent saline formation is possible with minimal pipeline construction. The post-combustion capture plant is an amine-based conventional absorber-stripper scrubbing system with a non-proprietary solvent. The anticipated capture quantity is 645,000 to 1 million tons per year depending on the EGU capacity factor.[63]
- Piperazine/Advanced Stripper Front-End Engineering Design (PZAS FEED). The University of Texas at Austin in partnership with Honeywell will conduct a FEED study for the Piperazine Advanced Stripper (PZAS) process for $CO_2$ capture at the Mustang Station 430-MW (gross) unit of Golden Spread Electric Cooperative (GSEC) in Denver City, Texas. This solvent, combined with the "flash-stripping" process improvement, is intended to reduce auxiliary energy demand

[63] Elliott, William R. (2021). *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines)*. Accessed at https://www.osti.gov/servlets/purl/1836563.

and lower capital cost. The PZAS is an advanced $CO_2$ scrubbing process with solvent regeneration for post-combustion carbon capture from natural gas flue gas. The anticipated capture quantity is 1.6 MMT per year depending on capacity factor.[64]

- Front End Engineering Design of Linde-BASF Advanced Post-Combustion $CO_2$ Capture Technology at a Southern Company Natural Gas-Fired Power Plant. Southern Company Services will complete a FEED study for the installation of a Linde-BASF aqueous amine solvent-based post-combustion $CO_2$ capture technology at an existing domestic natural gas-fired combined cycle power plant within Southern Company's portfolio of assets. The two sites considered are Alabama Power Company's Plant Barry in Bucks, Alabama, and Mississippi Power Company's Plant Daniel Unit 4 (525-MW gross) located in Moss Point, Mississippi. The Linde-BASF technology is based on a typical lean-rich solvent absorption/regeneration cycle for $CO_2$ capture and leverages several innovative features for both solvent and process optimization.[65]
- Front End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant. Electric Power Research Institute (EPRI) will conduct a FEED study to determine the technological and economic feasibility of retrofitting California Resources Corporation's 550-MWe Elk Hills Power Plant (EHPP), located in Kern County, California, with a post-combustion carbon capture technology.[66] The team will use Fluor's second generation amine-based Econamine FG Plus refined process design to capture 95 percent of the $CO_2$ produced by the EHPP. Elk Hills is located within the existing Elk Hills oil field, with $CO_2$ use for enhanced oil recovery requiring construction of minimal pipeline infrastructure. Overall, about 4,000 tonnes of $CO_2$ per day could be captured and delivered for use in enhanced oil recovery.
- A FEED study led by EPRI for the University of Kentucky solvent-independent low-cost $CO_2$ capture process retrofitted to the LG&E-KU Cane Run #7 700 MWe natural gas combined cycle power plant. An optimized aqueous amine absorption capture process will be applied to capture approximately 1,700,000 tonnes/year of $CO_2$ at >95% capture rate. The combined cycle facility is representative of power plants where variable renewable power and geographical storage for $CO_2$ is limited. The FEED package will provide engineering and cost information relevant to retrofitting a carbon capture process on combined cycle facilities.[67]
- A FEED study for retrofitting ION Clean Energy Inc.'s post-combustion $CO_2$ capture technology at Polk Power Station—an existing 1,190-MW combined cycle power plant. The project will be capable of capturing nearly 3.7 million metric tonnes of $CO_2$ per year and will utilize ION's transformational solvent (ICE-31), which has been developed and demonstrated by ION to achieve a minimum of 95% $CO_2$ capture with exceptional long-term stability.[68]
- A FEED study led by Wood Environmental & Infrastructure Solutions for retrofitting the commercially-operated Shell Chemicals Complex in Deer Park, Texas with $CO_2$ capture. The

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[64] Suresh Babu, Athreya, and Rochelle, Gary T. (2022). *Process design of the piperazine advanced stripper for a 460 MW NGCC*. Accessed at https://www.osti.gov/biblio/1854423.
[65] Lunsford, Landon, et al. (2022). *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*. Accessed at https://www.osti.gov/servlets/purl/1890156.
[66] Bhown, Abhoyjit S. (2022). *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant*. Accessed at https://www.osti.gov/servlets/purl/1867616.
[67] https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515
[68] https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515

project will reduce $CO_2$ emissions by 95 percent from several plants, including an on-site natural gas combined heat and power plant, using a post-combustion technology.[69]

DOE further announced[70] on May 5, 2023, the selection of additional CCS retrofit projects at existing NGCC plants to be awarded funding for FEED studies, including:

- Post-combustion CCS at Duke Energy's coal- and natural gas-fired integrated gasification combined cycle facility in Edwardsport, Indiana. The proposed design will use post-combustion capture of $CO_2$ from the combustion flue gas of different fuels including coal-gasified syngas, natural gas and blends of syngas and natural gas to capture an estimated 3.6 million metric tons of $CO_2$ per year.
- Full-scale, integrated, post-combustion solvent-based $CO_2$ capture from the NGCC facility at Entergy Louisiana LLC's Lake Charles Power Station in Westlake, Louisiana, will capture nearly 2.5 million metric tons of $CO_2$ per year. The proposed project includes the transport and geologic sequestration of $CO_2$ at a nearby storage site.
- Post-combustion solvent-based CCS at the Taft cogeneration power plant (includes an NGCC unit) in Hanville, Louisiana, to capture up to 3 million metric tons of $CO_2$ per year.

Other Natural Gas Combustion Turbine CCS Projects on Existing Units[71]

- A FEED study for post-combustion CCS from the 550 MW NGCC facility at the Quail Run Energy Center in Odessa, Texas will capture over 1.5 million metric tons of $CO_2$ per year.[72]
- A FEED study of post-combustion CCS at Chevron's 50 MW Kern River Eastridge cogeneration plant in Kern County, California will capture an estimated 300,000 metric tons of $CO_2$ per year.[73]

Natural Gas Combustion Turbine CCS Research Projects[74, 75]

- GE Research in Niskayuna, New York will develop a design to capture up to 95 percent of $CO_2$ from NGCC flue gas with the potential to reduce electricity costs by at least 15 percent.
- The Gas Technology Institute intends to develop a membrane technology capable of capturing more than 97 percent of $CO_2$ from NGCC flue gas. The project seeks to demonstrate a 40 percent reduction in the cost of CCS.

[69] https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon .

[70] https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies

[71] https://www.catf.us/2023/02/time-now-biden-administration-must-adopt-strict-co2-emission-standards-power-sector/

[72] https://www.ogci.com/climate-investments/investment-portfolio/quail-run/; https://assets.comptroller.texas.gov/ch313/1701/1701-ector-quail-appamend1.pdf

[73] Chevron launches Calif. carbon capture project while putting another on hold; https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/chevron-launches-calif-carbon-capture-project-while-putting-another-on-hold-70449975

[74] DOE (2021). *DOE Invests $45 Million to Decarbonize the Natural Gas Power and Industrial Sectors Using Carbon Capture and Storage*. Accessed at https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon.

[75] DOE (2022). *Additional Selections for Funding Opportunity Announcement 2515*. Office of Fossil Energy and Carbon Management. Accessed at https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515.

- RTI International plans to test a novel non-aqueous solvent technology in small capture plants with rotating packed bed absorbers. The project aims to demonstrate 97 percent or higher $CO_2$ capture from simulated NGCC flue gas.

**International Project Examples**

In addition to the projects in the United States, there are multiple international CCS projects for combined cycle combustion turbines. Mitsubishi Heavy Industries Engineering, Ltd. (MHIENG), part of Mitsubishi Heavy Industries (MHI) Group, was awarded a Front-End Engineering Design (FEED) study of a $CO_2$ capture plant applied to natural gas-fired combustion turbines for a repowered combined cycle power plant in Alberta, Canada, from Capital Power Corporation ("Capital Power").[76] The objective of this FEED study is to implement the $CO_2$ capture plant at the repowered Genesee Generating Station Units 1 & 2. MHIENG's "Advanced KM CDR Process™" will be deployed at these stations. The total expected amount of captured $CO_2$ will be approximately 3 million tonnes per year. The captured $CO_2$ will be transported and sequestered underground. For the execution of the FEED study, MHIENG partnered with Kiewit Energy Group Inc. ("Kiewit"), a North American construction and engineering company, and both companies will work together with Capital Power. Operation with this system is scheduled in 2023 and 2024 at Generating Stations 1 and 2, respectively.

MHIENG (originally MHI) has been developing the KM CDR Process™ (Kansai Mitsubishi Carbon Dioxide Recovery Process) and the Advanced KM CDR Process™ in collaboration with Kansai Electric Power since 1990. As of July 2022, the KM CDR Process™ has been adopted at 14 plants worldwide, and two more are currently under construction. The Advanced KM CDR Process™ uses KS-21™, which is an improvement over amine absorber KS-1™, at all 14 adopted commercial $CO_2$ capture plants to date. It has the benefits of enhanced regeneration efficiency and low deterioration when compared to KS-1™ and has been verified to provide energy-saving performance, reduce operation costs, and have low amine emissions.[77]

In the United Kingdom, the Net Zero Teesside Power (NZT Power) combined cycle project, a joint venture between BP and Equinor, with BP leading as operator, is expected to provide flexible, dispatchable low-carbon electricity.[78] In December 2022, the project's developers awarded FEED contracts to two separate consortia of engineering companies, carbon capture technology providers, and EPC contractors, the idea being to instigate a competition between the two consortia. The two selected contractor groups are:

- **Technip Energies and General Electric consortium,** led by Technip Energies and including Shell as a subcontractor for the provision of its Cansolv $CO_2$ capture technology and Balfour Beatty as the nominated construction partner.
- **Aker Solutions, Doosan Babcock, and Siemens Energy consortium,** led by Aker Solutions and including Aker Carbon Capture as a subcontractor for the provision of its $CO_2$ capture technology.

The plan is that the two consortia will work on design and development plans for NZT Power's proposed up to 860-MW combined cycle power station with carbon capture plant and each deliver a

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[76] https://www.mhi.com/news/220711.html
[77] https://www.mhi.com/products/engineering/co2plants.html
[78] https://www.netzeroteesside.co.uk/project/; https://www.nsenergybusiness.com/features/ccgtccs-integration-attracts-increased-attention/

“comprehensive” FEED package within 12 months. Following the completion of the FEED process, the two consortia will submit EPC proposals for the execution phase. Then as part of the final investment decision expected in 2023, a single consortium will be selected to take the project forward into construction. The contracts also include FEED for the planned facilities that will gather and compress $CO_2$ from NZT Power and other regional sources and export it offshore for permanent sub-surface storage. These facilities will also take $CO_2$ captured from a range of projects in the Humber region.

NET Power is targeting the Wilton International site at Teesside for its first power plant in the United Kingdom.[79] Whitetail Clean Energy is projected to feature a 300-MW combined cycle combustion turbine that will utilize NET Power’s proprietary Allam-Fetvedt cycle (described earlier in this document). The power plant is expected to be operational in 2025 and will sequester its captured $CO_2$ in deep-sea geologic formations. Project developers include U.S.-based 8 Rivers Capital and its UK affiliate, Zero Degrees Whitetail Development Ltd., and Sembcorp Energy UK. A pre-FEED study has been completed by 8 Rivers. NET Power also recently announced the development of two 300-MW combined cycle projects at the Wilhelmshaven Green Energy Hub in Germany.[80]

Other carbon capture projects at natural gas-fired plants in the United Kingdom include Keadby 3 and Staythorpe. The Keadby 3 Carbon Capture Power Station received a development consent order (DCO) from the UK government in December 2022 and is being developed by SSE Thermal and Equinor.[81] The $CO_2$ captured at the 910-MW plant will share transport and sequestration infrastructure, known as the East Coast Cluster, with other power producers and industries in the region. Keadby 3 is expected to offset 1.5 million metric tons of $CO_2$ per year, which is 15% of the 10 million metric tons the United Kingdom is targeting to eliminate annually by 2030. Meanwhile, the Staythorpe project includes adding carbon capture technology to retrofit an existing 1.7 GW combined cycle plant as well as the construction of a new combined cycle plant with carbon capture at another site in the region. [82] These projects will also utilize the same shared regional $CO_2$ transportation and storage infrastructure as the other UK projects listed in this section.

**Technologies designed for low $CO_2$ concentrations**

There are also technologies being developed specifically for lower $CO_2$ concentrations that could be applicable for combustion turbines. One company has announced it has developed membrane technology that is a carbon capture solution for small scale and low $CO_2$ concentrations, such as gas-fired boilers and combustion turbines. They have a commercial pilot in Magnolia, Arkansas, designed to demonstrate carbon capture at a small emitter (a natural gas-fired reboiler that emits 700 tonnes of $CO_2$ per year with a 4.5 percent $CO_2$ concentration). The overall aim of the project (with a third-quarter 2022

[79] SNC-Lavalin Group. (September 9, 2021). Atkins appointed as engineering solutions provider for Teesside Net Zero emissions NET power plant. Accessed at https://www.snclavalin.com/en/media/trade-releases/2021/2021-09-09.
[80] Patel, S. (December 22, 2022). *NET Power Consolidates Business to Gear Up for Allam Cycle Power Plant Deployment*. Power. Accessed at https://www.powermag.com/net-power-consolidates-business-to-gear-up-for-allam-cycle-power-plant-deployment/.
[81] SSE Thermal. (2023). Keadby 3 Carbon Capture Power Station: Capturing the potential of the Humber. Accessed at https://www.ssethermal.com/flexible-generation/development/keadby-3-carbon-capture/.
[82] https://www.rwe.com/en/press/rwe-generation/2022-12-20-rwe-enters-partnership-with-harbour-energy-to-explore-ccs-opportunities-at-uk-po/

delivery date) is to demonstrate capture as well as utilization of the captured $CO_2$ into the battery industry.[83]

FlexPower Plus® is a technology that combines natural gas-fired reciprocating engines with carbon capture.[84] Lean burn natural gas-fired reciprocating engines typically have $O_2$ concentrations of approximately 8 percent, closer to levels typical in combustion turbines than coal-fired boilers. Construction commenced in March 2022 on a full $CO_2$ capture project that is expected to be completed in the third quarter of 2023.[85]

[83] https://aqualung-cc.com/case-studies/#energy and https://aqualung-cc.com/standard-lithium-initiates-arkansas-carbon-capture-project-together-with-aqualung-carbon-capture-and-mission-creek-resources/
[84] https://www.lmph-uk.com/solutions/
[85] https://www.insidermedia.com/news/midlands/work-starts-on-carbon-capture-power-generation-project