Greenhouse Gas Mitigation Measures for Steam Generating Units

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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Chapter 1: Introduction

Under the authority of Clean Air Act (CAA) sections 111(b) and 111(d), EPA is proposing CO_2 emission guidelines for existing, new, modified, and reconstructed fossil fuel-fired electric generating units (EGUs). More specifically, EPA is proposing (1) limitations on carbon dioxide (CO_2) emissions based on the best system of emission reduction (BSER), and the appropriate degree of emission limitation for existing sources, and (2) new source performance standards for newly constructed sources. The proposed actions reflect the "best system of emission reductions … adequately demonstrated" for CO_2 emissions from the EGU source category. This technical support document (TSD) provides additional information, data, and analysis to support EPA's assessment and application of BSER. This TSD includes an assessment and evaluation of emission reduction technologies and/or pollution controls available to existing and newly constructed sources, at the source of emissions.

The technologies and controls described in this TSD include (1) increasing the operational efficiency (heat rate) of existing coal-fired steam EGUs, (2) increased use of cleaner and lower-emitting fuels (natural gas) at existing sources, and (3) carbon capture technology (with requisite transport and storage of CO_2). A chapter is devoted to each measure, with detailed information and EPA's evaluation of technologies for consideration as the best system of emission reduction. While evaluating each measure, EPA considered the engineering, technical feasibility, applicability and use, application level appropriate for BSER, and costs associated with reducing GHG emissions at EGUs. Where appropriate, this document distinguishes between existing and new sources, and unique aspects of mitigation measures.

Chapter 2: Heat Rate Improvement at Existing Fossil Fuel-Fired Steam Generating Units

This chapter presents an overview of some of the technologies available to improve efficiency at existing fossil fuel-fired EGUs. Heat rate is a common way to measure EGU efficiency. As the efficiency of a coal-fired EGU is increased, less coal is burned per kilowatt-hour (kWh) generated by the EGU resulting in a corresponding decrease in CO_2 and other air emissions. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) required to generate a kilowatt-hour (kWh) of electricity. Lower heat rates are associated with more efficient coal-fired EGUs.

The electric energy output for an EGU can be expressed as either as "gross output" or "net output." The gross output of an EGU is the total amount of electricity generated at the generator terminal. The net output of an EGU is the gross output minus the total amount of auxiliary (or parasitic) electricity used to operate the EGU (e.g., electricity to power fuel handling equipment, pumps, fans, pollution control equipment, and other on-site electricity needs), and thus is a measure of the electricity delivered to the transmission grid for distribution and sale to customers. Some Heat Rate Improvements (HRI) only affect improvement on a net basis by reducing the auxiliary load.

During normal operation, components may wear down, erode, buildup scale or experience fouling. This can have an effect of worsening the heat rate and, as a consequence, the emission rate. To counter these effects, as a part of regular or preventative maintenance various components are replaced with in-kind (*i.e.*, similar) components and equipment is otherwise cleaned, descaled, etc. Some of the preventative maintenance occurs following guidance from original equipment manufacturers. For example, to avoid catastrophic failure of steam turbine blades due to mechanical fatigue, turbine manufacturers typically have recommendations and programs to effect regular replacement of turbine blades with in-kind components. Maintenance activities in general may typically occur during scheduled annual shutdowns. Collectively, some level of performance is recovered by performing these various actions. However, that recovery in performance due to these regular maintenance activities is only near to the recent levels of performance, and not in exceedance of original design efficiencies.

Comparatively, equipment upgrades – that is replacement of components or re-design with alternatives having superior performance – result in improvement in performance, heat rate, and emission rate over recent levels.

Here, the EPA evaluates various HRI, based in part on information provided in a 2023 HRI report by Sargent and Lundy (S&L)[1], available in the docket. The 2023 S&L HRI report is an update of the findings of the 2009 S&L HRI report.[2] In general, the reductions achievable through HRI technologies were determined to be low and less than previously estimated. Additionally, many HRI only result in improvements on a net basis.

When evaluating HRI in previous rulemaking the EPA included various technology options in addition to best practices for operating and maintenance. The definition of "improve" is to "enhance in quality or value; make better."[3] Heat rate improvements therefore constitute actions or technologies which enhance or better the heat rate. Here, the EPA makes a distinction between actions that recover heat rate to recent levels and those that result in improvements. While "best practices" for operation and maintenance could result in improvements if not already undertaken, the 2023 S&L HRI report supports that "best practices" are generally performed as a part of normal operation and maintenance by most units and/or would not result in improvement of heat rate over recent levels. Similarly, in-kind component replacements are performed as part of regular operation and maintenance. Therefore, the EPA is not

[1] Heat Rate Improvement Method Costs and Limitations Memo. Sargent and Lundy, 2023.
[2] Coal-Fired Power Plant Heat Rate Reductions. Sargent and Lundy, 2009.
[3] *https://www.merriam-webster.com/dictionary/improve.*

including in-kind replacements or operating and maintenance practices in its evaluation of HRI. That distinction is clarified in the section 2.1 of this document for the different technologies, as appropriate.

Finally, the EPA evaluated the various limitations of HRI technologies for fossil fuel-fired steam generating units. Because the reductions that are achievable by HRI are small, and because of the potential for a rebound in cumulative emissions, the EPA is not proposing HRI as BSER for existing steam generating units.

2.1 Heat Rate Improvement Technology Options

There are a number of specific plant systems and equipment where efficiency improvements can be realized, either through new installations or modifications, which can provide heat rate reductions/improvement.

2.1.1 Improvements or Upgrades to the Boiler Island

2.1.1.1 Economizer Upgrades or Replacement

The economizer extracts energy from the combustion gases as they exit the furnace. This energy is used to preheat the water returning to the boiler. This heat exchanger improves efficiency by reducing the amount of fuel required to convert water into steam. Performing an economizer upgrade or replacement can yield improvements in heat rate in some cases, but other factors limit the applicability of the technology and the improvements it can achieve. Economizer upgrades can have a negative impact on Selective Catalytic Reduction (SCR) equipment, an increase in corrosion rates in downstream equipment, physical/spatial limitations, potential steaming in economizer tubes, and other drawbacks. Gross improvements in gross heat rate range from -0.82% to 0.75%.

2.1.1.2 Neural Network Control Systems (NN) and Intelligent Sootblower Systems (ISB)

NN and ISB are often installed together. NN are software computer models that are tied into the plant's distributed control system and adjust plant operation based on real-time operating data. NN can be applied for combustion control, optimize superheat and reheat steam temperatures, superheat and reheat steam spray flows, and other processes. For combustion control, NN are typically tuned to reduce nitrous oxide (NO_X) and carbon monoxide (CO) emissions, tuning the NN to maximize combustion efficiency can have an adverse impact on those non-GHG emissions.

ISB can improve performance by reducing the steam used for sootblowing or improving ash removal from boiler tubes. Improvements from NN and ISB are not additive. Cumulative improvements in gross heat rate range from 0% to 1.9%, 0.58% on average, and depend on various unit specific factors.

2.1.1.3 Air Heater Leakage Mitigation

Air heaters transfer heat between the incoming pre-combustion air and the exiting flue gas. By preheating the combustion air, less fuel is required to convert pre-heated water to steam. Due to their design, leakage can occur and, as a result, reduce the pre-combustion air temperature, requiring greater fuel consumption. Leakage also increases auxiliary power requirements since equipment must now handle the increased volume of air from the in-leakage. The suitability of seal upgrades depends on the design of the air heater. The HRI and costs depend on the extend of the replacement, whether in-kind or an upgrade, and other modifications. Improvements in net heat rate range from 0.23% to 2.23% for upgraded seals and other improvements.

2.1.2 Improvements or Upgrades to the Steam Turbine

2.1.2.1 Turbine Overhaul and Upgrade

The steam turbine extracts energy from the steam and rotates a generator to produce electricity. Overhauls are comprised of replacement and restoration of turbine parts and components to return efficiency and output to design standards, but not above them. Turbine overhauls are performed as typical maintenance. Because overhauls do not provide an improvement in performance over design levels and are already performed as a part of regular maintenance, they do not constitute HRI.

However, modern developments allow the steam turbine to extract more energy from the same amount of steam than was possible with equipment from decades ago. Upgrading turbines with improved internals can reduce gross heat rate. Different sections of the turbine steam path can be upgraded (HP – high pressure; IP – intermediate pressure; LP – low pressure). Full steam path upgrades can result in HRI from 1.50% to 5.15% on a gross basis.

2.1.2.2 Feedwater Heater

Boiler feed water heaters pre-heat the water going to the boiler. The hotter the water entering the boiler, the less energy it takes to convert it to steam. Like any heat exchanger, EGUs can improve efficiency by removing built-up scale or increasing heat transfer surface area. Chemical cleaning removes scale and restores heat transfer efficiency. However, these cleaning activities are often a part of typical maintenance, and while they may restore efficiency, they do not improve heat rate beyond design levels, and do not constitute HRI. However, modifying surface area can result in small heat rate improvements on a gross basis.

2.1.2.3 Condenser Cleaning

Condensers are subject to fouling and plugging, which directly impact the heat transfer efficiency and water quality. Tube cleaning can be performed as needed, but again, this is likely performed as a part of regular maintenance during annual outages and, while restorative, does not constitute HRI. Additionally, most units already maintain good water chemistry to reduce scaling. However, online cleaning systems can be installed, although benefits may be minimal relative to regular maintenance during outages.

2.1.2.4 Boiler Feed Pump Upgrades

Boiler feed pumps require auxiliary power to pump large amounts of boiler feed water through the heaters and the boiler. Due to their continuous operation, the pumps wear over time, lose efficiency, and require more energy to move the same volume of water. A pump overhaul restores efficiency of the degraded component. However, most units already perform regular boiler feed pump overhauls, and overhauls do not improve the heat rate beyond the original design level and therefore do not constitute HRI. Boiler feed pump technology has not advanced in the past 20 years, and efficiency improvements from upgrades are therefore limited or have already been applied.

2.1.3 Other Heat Rate Improvement Opportunities

2.1.3.1 Flue Gas System

The fans used to move flue gases typically require large amounts of auxiliary power to properly operate equipment. Benefits of upgrading forced draft fans are minimal. Upgrading induced draft fans from centrifugal to axial fans with variable pitched blades can provide some HRI on a net basis, however these benefits are relatively low. Furthermore, many units have already applied this update when installing FGD or SCR emission controls.

2.1.3.2 Air Pollution Control Equipment

Coal-fired steam generating units typically have some level of air pollution control equipment. This may include flue gas desulfurization (FGD) for SO_2 control, electrostatic precipitators (ESP) or baghouses for particulate matter (PM) control, and selective catalytic reduction (SCR) for NOx control. These controls require some level of auxiliary power. In general, the potential HRI are realized by reducing pressure drop or decreasing the operation of these controls when emission limits are more than adequately satisfied. However, the HRI are relatively low, are observed on a net basis, and there is concern that adequate emissions control may be compromised by some of the HRI methods.

2.1.3.3 Water Treatment System

As noted in the 2009 S&L HRI report, most steam generating units already have the most advanced water treatment systems installed, and few opportunities for HRI are therefore available. Changes to cooling tower operation can result in low HRI, however, most units have already adopted those methods.

2.2 Limitations of HRI

2.2.1 CO_2 Reductions from HRI

Most HRI technology measures achieve only small reductions or have already been applied at most units in the fleet (see the 2023 S&L HRI report, and reductions noted above). Furthermore, the 2023 S&L HRI report estimates reductions that are, in general, less than those in the 2009 S&L HRI report. Additionally, many HRI technologies only affect HRI on a net basis. Although improvements on a net basis may be beneficial, measurement of emission rates on a net generation basis can be challenging. Power plants often include multiple steam generating units, and it can be difficult to attribute reductions on a net basis to individual units as the auxiliary power requirements are distributed across the plant. Even assuming many of the HRI measures could be applied to a unit, adding together the upper range of some of the HRI percentages in the 2023 S&L HRI report could yield an emission rate reduction of around 5 percent. However, the reductions that the fleet could achieve on average are likely much smaller. The 2023 S&L HRI report notes that, in many cases, units have already applied HRI upgrades or that those upgrades would not be applicable to all units.

2.2.2 Potential for Rebound in CO_2 Emissions

Reductions achieved on a rate basis from HRI may not result in overall emission reductions and could instead cause a "rebound effect" from increased utilization. A rebound effect would occur where, because of an improvement in its heat rate, a steam generating unit experiences a reduction in variable operating costs that makes the unit more competitive relative to other EGUs and consequently raises the unit's output. The increase in the unit's CO_2 emissions associated with the increase in output would offset the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of output. The extent of the offset would depend on the extent to which the unit's generation increased. The CPP did not consider HRI to be BSER on its own, in part because of the potential for a rebound effect. Analysis for the ACE Rule, where HRI was the entire BSER, observed a rebound effect for certain sources in some cases. In this action, where different subcategories of units are proposed to be subject to different BSER measures, steam generating units in a hypothetical subcategory with HRI as BSER could experience a rebound effect. Because of this potential for perverse GHG emission outcomes resulting from deployment of HRI at certain steam generating units, coupled with the relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not proposing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

Chapter 3: Co-firing Lower Emitting Fuels at Existing Coal-Fired EGUs

3.1 Introduction

Co-firing of fuels is one method capable of reducing the CO_2 emission intensity of electricity delivered from existing, predominantly coal-fired EGUs. While co-firing could occur with a variety of fuel sources, such as natural gas, biomass, or oil, this chapter will focus primarily on co-firing of natural gas at existing coal-fired EGUs.

The combustion of natural gas in a boiler originally designed for coal-fired generation is one approach to reducing the CO_2 emissions rate in these boilers. The CO_2 emission rate is reduced when natural gas is substituted for coal because the gas has a much higher percentage of hydrogen and a lower percentage of carbon than the coal it replaces. When quantities of gas and coal are burned with oxygen from air to produce the same amounts of heat, the higher hydrogen content of natural gas produces more water vapor (H_2O) than coal, but far less CO_2. According to EIA, coal consumption for electricity generation produces 209 pounds of CO_2 per million British thermal units (MMBtu), compared with 117 pounds of CO_2/MMBtu for natural gas.[4]

The discussion below focuses solely on the conversion of an existing coal-fired boiler to burn natural gas instead of, or along with, coal. There are other technical options for gas substitution in an existing coal-steam EGU that are not examined in any detail here. They include:

- Complete coal-to-gas conversion of an existing coal EGU to only burn 100 percent natural gas, including removal of the capability to burn coal.
- Repowering an existing coal EGU by providing heat input to the boiler from the exhaust of a newly installed gas turbine generator; and,
- Gasification of coal, producing syngas (a mixture of gases including CO and H_2) that can be combusted after additional processing in the existing coal-fired boiler.

These other options have higher capital cost and thus would not be as economic as the direct substitution of natural gas in an existing coal boiler.

This chapter summarizes the technical considerations associated with this technology, and evaluates the technical feasibility, cost-effectiveness, and potential emissions reductions attributable to deployment of this measure.

3.2 Description of Natural Gas Co-firing Technology Options

One approach for reducing the CO_2 emissions rate from an EGU designed for coal-fired generation is to substitute natural gas for some or all of the coal. This ability for a boiler to simultaneously fire a combination of coal and natural gas is known as "natural gas co-firing." Many existing coal steam boilers already use some amount of natural gas. For units that use natural gas for boiler light off, initial warming, and low load operation, co-firing capability is already present but may not be used for normal load generation. In comparison, dual-fuel firing capability is the ability to independently fire either coal or natural gas and achieve full load with either fuel. Lastly, a coal-to-gas conversion involves modifying a unit to only fire 100 percent natural gas, and as mentioned, is not considered here.

3.2.1 Co-firing of Natural Gas at Existing Coal-Fired EGUs

[4] https://www.eia.gov/todayinenergy/detail.php?id=48296#.

3.2.1.1 Defining the Level of Co-firing

When specifying a level of natural gas co-firing, it is important to note that the period of time over which that level is specified could vary. One possibility is the design (hourly) values, or the percentage of total heat input that the boiler is capable of operating with using natural gas at any given moment. It is also possible to state the longer term (e.g., annual) percentage of heat input that is natural gas. This longer-term, or annual average percentage could include periods of higher and lower natural gas use.

3.2.1.2 Engineering Considerations

Most existing coal-fired EGU boilers can be modified to fire up to 100 percent gas input, and there are several different options for doing so. These options can be broken into two general categories: supplemental co-firing and reburn co-firing. Supplemental co-firing describes a configuration wherein the gas burners are placed within the existing burner belt. Reburn co-firing describes a configuration wherein the gas burners are placed above the existing burner belt, thereby effectively "reburning" the combustion products as they rise up from the burner zone.

Modifying existing coal-fired boilers to enable natural gas firing typically involves installation of new gas burners and supply piping, modifications to combustion air ducts and control dampers, and possibly modifications to the boiler's steam superheater, reheater, and economizer heating surfaces that transfer heat from the hot flue gas exiting the boiler furnace. The conversion may also involve some modification of downstream air pollution emission control equipment. Engineering studies are performed to assess changes in furnace heat absorption and exit gas temperature; material changes affecting heat transfer surfaces; the need for sizing of flue gas recirculation fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

The introduction of natural gas co-firing will cause boilers to be slightly less efficient due to the high hydrogen content of natural gas. Compared to coal, natural gas contains a large fraction of hydrogen (approximately 24 percent by weight). When combusted, the additional hydrogen yields increased moisture content (water vapor) in the flue gas. The increased moisture content, in turn, results in additional heat lost up the stack instead of being directed towards electricity generation, thereby decreasing boiler efficiency slightly. Co-firing at levels between 20 percent and 100 percent can be expected to decrease boiler efficiency between 1 percent and 5 percent.

Despite the decrease in boiler efficiency, the overall net output efficiency of a coal-steam boiler EGU that switches from coal to natural gas firing may change only slightly, in either a positive or negative direction. Since co-firing reduces coal consumption, the auxiliary power demand related to coal handling and emissions controls typically decreases as well. While a site-specific analysis would be required to determine the overall net impact of these countervailing factors, generally the effect of co-firing on net unit heat rate can vary within approximately +/-2 percent. In the cost analysis conducted below, we assume an average 1 percent net heat rate increase results from the conversion of a coal steam boiler to 40 percent natural gas co-firing.

Finally, natural gas co-firing has the potential for improved low load capability. For coal firing, the "turn-down ratio" is dependent on the quantity and turn-down capabilities of the pulverizers and the turn-down capabilities of all other associated balance of plant equipment, such as the fans and boiler feed pumps. Most conventional coal-fired boilers were designed with limited turndown range of 30 percent to 40 percent. For units capable of 100 percent gas firing, the "turn-down ratio" is not affected by the coal pulverizers and can potentially be lower; however, this ratio is still dependent on the turn-down capabilities of all other associated balance of plant equipment. The potentially enhanced "turn-down ratio" capability with natural gas makes extended operation at low-load conditions significantly easier to maintain, either through the use of the natural gas ignitors, natural gas main burners, or a combination of the two.

3.2.1.3 Cost Considerations

There are several potential modifications that can be made to existing coal boilers to achieve additional gas co-firing capabilities. The applicability of the various types of modifications, and associated costs, will vary based on the degree of incremental co-firing. There are several options that can achieve a low range of co-firing with minor modifications, as well as more significant modifications which can achieve a much higher percentage of natural gas co-firing, up to 100 percent of heat input.

For moderate increases in natural gas co-firing, units with existing gas ignitors may be able to increase the gas use at those ignitors at a capital cost of roughly less than $2/kW. Similarly, units may be able to convert existing oil ignitors to gas ignitors for approximately the same cost. These small modifications could likely achieve co-firing levels of up to 20 percent of heat input.

In order to achieve natural gas co-firing levels of 40 percent or greater, most existing coal steam capacity would require the conversion of existing coal burners to dual fuel burners and/or the installation of new gas burners. Each of these modifications would enable the existing boiler to operate with natural gas at up to 100 percent of heat input, at a cost of approximately $52.2/kW. For boilers with existing natural gas warm-up guns that have the ability to co-fire beyond 15 percent natural gas, it may be possible to increase the ability to co-fire up to 100 percent natural gas for a capital cost of approximately $46.4/kW, depending on the quantity, design, and capability of the existing warm up guns.

Fixed O&M (FOM) costs can potentially decrease as a result of decreasing the amount of coal consumed, resulting from a reduction in frequency of maintenance, reduced on-site coal handling, and an overall reduction in auxiliary power. However, it is common for plants to maintain operation of one coal pulverizer at all times, which is necessary for maintaining several coal burners in continuous service. In this case, coal handling equipment would be required to operate continuously and therefore natural gas co-firing would have limited effect on fixed O&M costs.

Potential variable O&M (VOM) cost impacts are limited to any incremental fuel costs. Typically, the delivered cost of natural gas is greater than the delivered cost of coal on a $/MMBtu basis. Therefore, variable costs would increase as a result of the fuel price differential. Additionally, if the net heat rate is increased because of the boiler efficiency decrease, an overall increase in the amount of fuel consumed would increase slightly, assuming that the same amount of electricity is generated. As discussed above, the impact on net heat rate could range from -2 percent to 2 percent.

3.2.1.4 Timing Considerations

Any necessary boiler modifications that might be required to achieve natural gas co-firing levels of 40 percent or greater could be completed within three years. This three-year estimate is inclusive of time required for conceptual studies, specifications/awards, detailed engineering, site work/mobilization, construction, and startup/testing. The scope of the boiler modifications discussed above are similar to standard maintenance activities, and no long-term delays or schedule uncertainties are expected.

3.2.2 Pipeline Considerations for Natural Gas Cofiring at Existing Coal-Fired EGUs

In addition to any potential boiler modifications, the supply of natural gas is necessary to enable co-firing at existing coal steam boilers. As discussed in the previous section, many plants already have at least some access to natural gas. In order to increase natural gas access beyond current levels, it is necessary to construct natural gas supply pipelines. This section discusses natural gas pipeline sizing, cost, and timing considerations related to increasing natural gas supply at existing coal boilers

The U.S. natural gas pipeline network consists of approximately 3 million miles of pipelines that connect natural gas production with consumers of natural gas.[5] Those pipelines can be broken into three general types: gathering pipeline systems, transmissions pipeline systems, and distribution pipeline

[5] https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

systems.[6] Gathering systems deliver raw natural gas to processing facilities from production wells. Transmission systems consist of much longer, higher pressure pipelines that transport gas from the processing facilities to distribution centers or directly-served entities (e.g., power plants) via pipeline laterals. Transmission pipelines can range in size from 4 to 42 inches. Distribution pipelines are typically smaller and deliver gas mostly to residential and commercial consumers and some power plants and industrial facilities.

To increase natural gas consumption at coal-fired boilers without sufficient existing natural gas access, it is necessary to connect the facility to the natural gas pipeline transmission network via the construction of a lateral pipeline. The cost of doing so is a function of the total necessary pipeline capacity (which is characterized by the length, size, and number of laterals) and the location of the plant relative to the existing pipeline transmission network. The discussion below elaborates on each of these factors and describes EPA's approach for estimating pipelines costs associated with increasing co-firing at each existing coal-fired boiler up to 40 percent of capacity on an annual average basis.

3.2.2.1 Pipeline Capacity

The first consideration is the pipeline capacity that would be required to provide a sufficient volume of natural gas to enable an existing plant to co-fire. This section focuses on the total pipeline capacity, which can consist of one or more laterals of various lengths and sizes, depending on the location of the plant relative to the natural gas transmission network (see Plant Location section, below). The volume of gas required depends on the capacity of each plant, the intended dispatch of the plant's capacity, the heat rate, and the degree of co-firing desired. The Weymouth equation can be used to estimate the pipeline capacity necessary to supply a given volume of gas.

The theoretical maximum potential pipeline capacity would be sufficient to deliver a volume of gas necessary to supply 100 percent of plant capacity at full load, which would enable the plant to generate at its maximum potential using 100 percent natural gas. Most existing coal plants that modify to co-fire with natural gas would install significantly smaller laterals. This pipeline capacity would decrease to account for lower levels of operation and/or lower levels of co-firing.

It is important to consider plant operation, or generation, which is typically expressed as an annual average capacity factor. The annual average capacity factor for coal-fired EGUs over 2017-2021 is about 48 percent. This means that these plants are operating at 48 percent of their full potential, on average, over the year. There are likely periods of time where they are operating at a higher level and periods of time where they are operating at a lower level.

It is also important to consider the desired co-firing level, which can be expressed as an annual average percent of generation. Generally, a larger volume of gas would be required for higher levels of co-firing at plants with higher levels of generation. Like generation, the gas use could also vary over the course of a year – 40 percent annual average co-firing could be achieved by providing 40 percent of heat input in each hour with gas, or it could also be achieved by co-firing at higher levels during some hours and lower levels during others. Together, these two factors – the desired annual average co-firing level and the planned utilization – determine the pipeline capacity necessary to enable a desired level of co-firing.

In this TSD, EPA is estimating costs associated with 40 percent annual average co-firing at existing coal steam boilers. To do so, EPA assumes pipeline capacity equal to 60 percent of the net summer generating capacity at each plant. This estimate recognizes the importance of enabling flexibility in gas use, and provides a reasonable approximation of costs for the analysis presented in this TSD.

At all levels of operation, this pipeline capacity assumption enables the plant to co-fire beyond 40 percent of heat input. For example, when a plant is operating up to 60 percent load, it can co-fire up to

[6] https://primis.phmsa.dot.gov/comm/NaturalGasPipelineSystems.htm.

100 percent gas heat input. At base load levels (80 percent-100 percent), this pipeline capacity enables natural gas co-firing at 60-75 percent of heat input. This capacity also enables temporal flexibility. For every hour the plant is operating at full load and utilizing the full pipeline at 60 percent co-firing, it can co-fire for another hour at 20 percent, so that on average the plant is co-firing at 40 percent. And for every two hours the plant is utilizing the full pipeline, it can operate for an hour without any co-firing.

Each unit in the operating existing coal steam fleet operated below a 60 percent capacity factor for at least some hours over the 2017 to 2021 period. The percent of total operating hours operating below this level varies for each unit, up to 100 percent, with an average of 43 percent of total operating hours operating below a 60 percent capacity factor. EPA assumes similar dispatch patterns would enable these units to co-fire up to 100 percent gas for 43 percent of the operating hours, on average, using EPA's new pipeline capacity estimates (i.e., pipeline capacity equal to 60 percent of the net summer generating capacity at each plant). On average, these units were operating at or near full load (more than 80 percent capacity factor) only 21 percent of the time. During these hours, EPA's estimates of new pipeline capacity would enable these units to co-fire between 60 percent and 75 percent gas.

3.2.2.2 Plant Location

It is also important to consider the location of each plant relative to the existing natural gas transmission pipelines, as well as the available excess capacity of each of those pipelines. Once transmission pipelines with sufficient gas supply are identified, the cost consists of the construction costs of laterals to access that supply (which can be estimated on a regional $/inch-mile basis), along with any necessary compression needed to support the transport of gas to the plant. The remainder of this section summarizes the approach that EPA used to estimate the costs of laterals capable of supplying each coal steam boiler with a volume of gas that would be necessary to fuel 60 percent of the plant's net summer generating capacity.

EPA's cost analysis for this TSD related the locations of all existing coal boilers to the existing gas transmission network using National Pipeline Mapping System (NPMS) shapefiles that contain maps of pipelines throughout the United States, published by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). This enabled the identification of the lowest-cost option for each plant to construct up to two laterals sufficient to supply 60 percent of each plant's net summer generating capacity.

Next, the results were reviewed to assess the availability of the upstream natural gas pipeline capacity to satisfy the assumed co-firing demand at each plant via the new laterals. The assessment reviewed the reasonableness of each lateral assumption by determining whether the peak gas capacity of that lateral could be satisfied without modification of the transmission pipeline systems to which it is connected. This analysis found that most, if not all, pipeline systems are currently able to meet the peak needs implied by these new laterals in aggregate. It's important to note that this analysis was conducted to test the availability of the upstream pipeline network assuming that all new laterals in the analysis were constructed and utilized at the same time.[7]

3.2.2.3 Pipeline Development Timing Considerations

The oil and gas industry has extensive experience constructing natural gas pipelines. Based on data collected by EIA, over the last five year (2017-2021), the total annual mileage constructed ranged from approximately 1,000 to 2,500 miles per year, with a total capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion.

The time required to develop and construct natural gas laterals can be broken into three phases: planning and design, permitting and approval, and construction. It is reasonable to assume that the planning and design phase can typically be completed in a matter of months and will often be finalized in

[7] Documentation for the Lateral Cost Estimation (2023), ICF International.

less than a year. The time required to complete the permitting and approval phase can vary. Based on a review of recent FERC data, the average time for pipeline projects similar in scope to the projects considered in this TSD is about 1.5 years, and would likely not exceed 4 years. Finally, the actual construction could likely be completed in less than one year. Summing these estimates, it is likely that the pipeline projects considered in this TSD would require 3.5 years on average, from planning and design through construction, and it is unlikely that these projects would require more than 6 years in total.

3.3 Evaluation of Natural Gas Co-firing as BSER for Existing Coal-Fired EGUs

This section summarizes the technical feasibility and cost reasonableness of co-firing with 40 percent natural gas on an annual average basis. The technical information presented in this section supports the discussion presented in the preamble.

3.3.1 Technical Feasibility

Many existing coal steam boilers already use some amount of natural gas, and several have co-fired at relatively high levels in recent years. For many individual EGUs, switching to or co-firing with gas may be an attractive option for reducing CO_2 emissions.

For instance, it is common practice for EGUs to have the capability to burn multiple fuels onsite, and of the 565 coal-fired EGUs operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source. Coal-fired EGUs often use alternative fuel sources like oil or natural gas as a start-up fuel, warming the units up before running them at full capacity with coal. While start-up fuels are used at low levels (less than approximately 5 percent of heat input) some coal-fired EGUs have co-fired natural gas at higher operational shares. While these EGUs may only burn natural gas infrequently throughout the year, they may have the capability to burn natural gas at higher levels. For example, some existing coal-fired EGUs with natural gas co-firing can burn natural gas at levels equal to nearly 100 percent of heat input over an hour or more, with lower levels on average over the course of a year. This indicates higher levels of natural gas co-firing are immediately available at some sources.

Even if a generator doesn't necessarily report burning natural gas, in many cases, coal-fired EGUs are located in the vicinity of other generating assets. In the cases where coal-fired EGUs are located near natural gas EGUs, they likely have access to an existing supply of natural gas. For instance, 107 of the 565 coal-fired EGUs are located at facilities that also operate natural gas EGUs. In addition, 172 of the coal-fired EGUs operating at the end of 2021 also reported to EIA via Form 860 an affiliated natural gas local distribution company or pipeline. In combination, the majority of coal-fired EGUS, 369 of the 565 EGUs operating at the end of 2021, have either reported natural gas as a fuel source, are located at a plant with a natural gas generator, and/or are located at a plant with a natural gas pipeline connection.[8]

As natural gas prices have declined over the past decade, the quantity of natural gas consumed onsite by coal-fired EGUs has increased, becoming more common practice. Using reported data on monthly fuel consumption between 2015-2021, of the 565 coal-fired EGUs operating at the end of 2021, 162 coal-fired EGUs have reported more than one month of consumption of natural gas at their boiler and 29 coal-fired steam generating units co-fired at over 40 percent on an annual heat input basis in at least one year while also operating with annual capacity factors greater than 10 percent. Using hourly reported CO_2 emission rates between 2015-2020, we can also calculate the hourly consumption of natural gas at coal-fired boilers still in operation at the end of 2021. Here we similarly observed 29 coal-fired boilers with natural gas co-firing capability of 60 percent of capacity on an hourly basis, which reflects the estimated size lateral needed to operate flexibly to deliver co-firing at 40 percent on an annual heat input

[8] U.S. Energy Information Administration (EIA). Annual Electric Generator Report, 2021 Form EIA-860. See https://www.eia.gov/electricity/data/eia860/.

basis.[9] Lastly, many coal-fired EGUs have also opted to switch entirely to providing generation from natural gas. Since 2011, over 100 coal-fired plants have been replaced or converted to natural gas.[10]

3.3.2 Reasonableness of Costs

There are a variety of ways to assess and evaluate cost reasonableness for natural gas co-firing. The two metrics of interest examined in this TSD are cost per short ton of CO_2 removed and cost per MWh of electricity generated. This section estimates these two cost metrics using two different approaches: estimating the costs of a representative unit and estimating the costs of the fleet on average.

The cost estimates in this section are based on the assumption discussed below as well as two additional documents which are available in the docket. The first document describes the costs and performance assumptions related to modifying an existing coal boiler to co-fire with natural gas[11]. The second document describes the natural gas lateral pipeline cost estimates developed for each coal steam facility.[12]

3.3.2.1 Annual Cost Estimates for a Representative Unit

This section presents annual cost estimates for a representative baseload coal unit. This static analysis evaluates the incremental costs and CO_2 emissions reductions associated with a representative coal unit co-firing with 40 percent natural gas on an annual average basis relative to a baseline where the same coal unit operates with 100 percent coal. This estimate assumes no change in generation. The range of costs presented below are based on a range of potential capital amortization periods for such representative coal unit.

The key assumptions for this analysis are as follows:

- Unit characteristics are based on recent coal fleet averages:400 MW capacity; 10,000 Btu/kWh heat rate; 50 percent capacity factor
- Fuel costs are based on 2030 reference case projected average delivered costs: $1.47/MMBtu for coal; $2.53/MMBtu for natural gas
- CO_2 content of fuel: 205 lbs/MMBtu for coal; 117 lbs/MMBtu for natural gas
- Boiler modifications: $52.2/kW; 1 percent increase in heat rate
- Natural gas pipeline cost is the median value of the pipeline cost analysis: $92/kW

Table 1 presents the costs of a representative coal unit relative to both the estimated CO_2 emission reductions as well as the total generation. The range in this table reflects different potential capital amortization periods.

[9] United States Environmental Protection Agency (EPA). "Power Sector Emissions Data." Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data web site: https://campd.epa.gov.
[10] https://www.eia.gov/todayinenergy/detail.php?id=44636.
[11] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available at Docket ID EPA-HQ-OAR-2023-0072.
[12] Documentation for the Lateral Cost Estimation (2023), ICF International. Available at Docket ID EPA-HQ-OAR-2023-0072.

Table 1. Annual Cost Estimates, 40 percent Natural Gas Co-Firing (Representative Unit)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
10	53	9
6	66	12
5	73	13
2	130	23

3.3.2.2 Annual Cost Estimates based on Fleet Average

Like the previous section, this section evaluates the incremental costs and CO_2 emissions reductions of co-firing with 40 percent natural gas on an annual average basis relative to a baseline representing no natural gas co-firing (100 percent coal consumption). However, this section presents the fleetwide average incremental cost and reductions, under an assumption of fleetwide co-firing.

This analysis estimates the costs and reductions associated with co-firing 40 percent natural gas on an annual average basis for each existing unit, assuming a generation level consistent with a five-year average capacity factor[13] for each unit. EGUs with known plans to cease operations or convert to natural gas by 2030 were excluded from the analysis. The overall average presented below is based on the sum of costs and emissions reductions across these individual units. The range of costs presented below are based on a range of potential capital amortization periods. This analysis does not account for the fact that some boilers are currently capable of co-firing with natural gas, nor does it account for the presence of existing natural gas laterals.

The cost estimates in this section are based on the assumption discussed below as well as two additional documents which are available in the docket. The first document describes the costs and performance assumptions related to modifying an existing coal boiler to co-fire with natural gas[14]. The second document describes the natural gas lateral pipeline cost estimates developed for each coal steam facility[15].

The unit-level estimates of cost and emissions reductions for this analysis are based on the following key assumptions:

- The generation levels are consistent with a five-year average capacity factor

[13] Five-year average capacity factors were calculated for 2017-2021, using heat-input-based capacity factors. For EGUs with less than 20 percent five-year average capacity factors, a 20 percent capacity factor was applied. For EGUs missing capacity factor related data, a fleet-wide average capacity factor of 43 percent was applied. Capacity factor data comes from: United States Environmental Protection Agency (EPA). "Power Sector Emissions Data." Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data web site: https://campd.epa.gov.
[14] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available at Docket ID EPA-HQ-OAR-2023-0072.
[15] Documentation for the Lateral Cost Estimation (2023), ICF International. Available at Docket ID EPA-HQ-OAR-2023-0072.

- Boiler modifications: $52.2/kW; 1 percent increase in heat rate
- CO_2 emissions rates for coal are based on a five-year average emission rate[16] and an assumption of 117 lbs/MMBtu for natural gas
- Fuel cost for coal is based on 2030 reference case projected average delivered cost: $1.47/MMBtu
- Fuel cost for natural gas is based on 2030 reference case projected average delivered cost ($2.53/MMBtu) and is assumed to increase to $2.91/MMBtu based on the implied increase in natural gas demand resulting from all units in the analysis co-firing at 40 percent natural gas on average, and an assumed elasticity of 1.1.
- Facility-specific natural gas pipeline cost estimates[17]

The unit-level estimates of cost and emissions reductions for this analysis are included in the docket.[18] Table 2 presents the fleetwide average incremental cost and reductions, under an assumption of fleetwide 40 percent natural gas co-firing, relative to operation without co-firing (100 percent coal). The range in this table reflects different potential capital amortization periods.

Table 2. Annual Cost Estimates, 40 percent Natural Gas Co-Firing (Fleet Average)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
10	64	11
6	78	14
5	85	15
2	148	27

The unit-level dollar per ton cost estimates are lower than the average value presented above for 82-83 GW (up to about 70 percent of total capacity included in this analysis), depending on the amortization period. Similarly, the unit-level dollar per MWh cost estimates are lower than the average value presented above for 85-86 GW (or about 72 percent of total capacity included in this analysis), depending on the amortization period.

3.3.3 Emission Reductions

One of the primary benefits of co-firing with natural gas is emissions reduction. In a co-firing environment, the original emissions control equipment must remain operational to process the remaining coal-based pollutants such as mercury, SO_2, and particulate which continue to be generated at lower

[16] Five-year average emission rates were calculated for 2017-2021. For EGUs with emission rates less than 190 lbs/MMBtu emission rate, 190 was used. For EGUs missing emission rate related data, a fleet-wide average emission rate of 206.3 lbs/MMBtu was applied. Emission rate data comes from: United States Environmental Protection Agency (EPA). "Power Sector Emissions Data." Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data web site: https://campd.epa.gov.

[17] Documentation for the Lateral Cost Estimation (2023), ICF International. Available at Docket ID EPA-HQ-OAR-2023-0072.

[18] See spreadsheet titled: Unit-Level Cost and Reduction Estimates for Natural Gas Co-Firing.xls.

concentrations roughly proportional to the percent co-firing. When shifting from 100 percent coal to 100 percent gas, CO_2 stack emissions are reduced approximately 40 percent. At lower levels of co-firing, the CO_2 emissions are reduced approximately 4 percent for every additional 10 percent of co-firing. When shifting from 100 percent coal to 60 percent coal and 40 percent natural gas, CO_2 stack emissions are reduced by approximately 16 percent. NO_X emissions are also typically reduced but the magnitude of the reduction is dependent on the combustion system modifications that are implemented.

Chapter 4: Carbon Capture and Storage

4.1 Introduction

Carbon capture and storage technology is currently the only add-on pollution control technology available to sources to reduce CO_2 emissions from fossil fuel-fired EGUs at the stack/point of combustion. CCS has been adequately demonstrated, is technically feasible, and can be implemented at reasonable cost. In addition, the technology provides the most significant emission reductions opportunity of any emission reduction technology or fuel currently available to sources to lower emissions. This section examines the application of CCS technology as the BSER for fossil fuel-fired steam generating EGUs, both existing and newly constructed sources. Included in this report are technical considerations, engineering aspects, transport and storage dimensions, and installation timeframes. Storage and transport considerations are also applicable to new and existing natural gas-fired combustion turbines. In general, much of the discussion of the CO_2 capture component is applicable to both combustion turbines and steam generating units, and distinctions are indicated where appropriate. Some aspects of CO_2 capture that are specific to natural gas-fired combustion turbines are discussed in the *Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines* TSD. Attached to this document is a spreadsheet with a list of CCS projects, including CO_2 transport and sequestrations projects and CO_2 capture projects at combustion turbines and coal-fired EGUs (CCS facility list.xlsx). CCS technology is applicable to both existing and newly constructed sources, and distinctions are indicated where appropriate.

The EPA included an extensive amount of information concerning all aspects of CCS in "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule," 80 FR 64510, 64548-93 (October 23, 2015) (2015 NSPS) and the accompanying technical documentation, "Technical Support Document – Literature Survey of Carbon Capture Technology" (July 10, 2015), "Achievability of the Standard for Newly Constructed Steam Generating EGUs" (July 31, 2015), and "Technical Support Document – Geographic Availability," much of which is relevant for the present proposal.

4.2 Description of Carbon Capture Options for EGUs

There are several technologies to capture CO_2 emissions at various stages of development, testing, and deployment. Capture of CO_2 from industrial gas streams has occurred since the 1930s, through use of a variety of approaches to separate CO_2 from other gases. These processes have been used in the natural gas industry and to produce food and chemical-grade CO_2. Commercially demonstrated CO_2 capture processes have achieved capture rates of 90 percent. In general, CO_2 capture technologies applicable to EGUs or other industrial sources can be categorized into three approaches. Pre-combustion systems are designed to separate CO_2 and H_2 in the high-pressure syngas produced via gasification. For coal-fired power systems this would be an IGCC power plants. Post-combustion systems are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air. Lastly, oxy-combustion uses high-purity O_2, rather than air, to combust coal (or other fuels) and thereby produce a highly concentrated CO_2 stream. Of the three approaches, the most relevant for retrofits to existing facilities and the most developed is post-combustion capture. Post-combustion capture may be accomplished using a solvent-based system, adsorption on solid particles, or membrane separation. Of those, solvent-based systems are the most technically developed and have been commercially demonstrated for carbon capture from coal-fired steam generating units and natural gas-fired combustion turbines.

4.2.1 Post-combustion Capture

Post-combustion CO_2 capture refers to removal of CO_2 from a combustion flue gas prior to discharging to the atmosphere. Because CO_2 is a dilute fraction of the combustion flue gas – typically 13-15 % in coal-fired systems and 3-4 % in natural gas-fired systems – a large volume of flue gas must be treated. The flue gas from typical combustion systems is usually at near atmospheric pressure. Therefore, most of the available capture systems rely on chemical absorption (chemisorption) options (e.g., amines) that require added energy to release the captured CO_2 and regenerate the solvent. Many of the chemical solvents require a flue gas stream that is free of or has very low quantities of co-pollutants– such as SO_2, NOx, and HCl – that can degrade the solvent.

4.2.1.1 Amine Technology

Solvent-based capture processes usually use an amine (e.g., monoethanolamine). Carbon capture occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with the CO_2 but will also react with contaminants in the flue gas including SO_2. Since the flue gas contaminants cause degradation of the solvent, the flue gas from coal-fired facilities typically must be treated (e.g., must pass through a flue-gas desulfurization (FGD) scrubber and often a secondary polishing column prior to entering the absorption column). The polishing column (i.e., quencher) also serves to reduce the temperature of the flue gas, which benefits the subsequent absorption step. After absorption, the amine solution passes to the solvent regeneration column where the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported offsite, usually by pipeline. The amine solution from the regenerating column is cooled and sent back to the stripping column, and any spent solvent that has irreversibly absorbed contaminants is replenished with new solvent.

Amine CO_2 capture is a chemical solvent-based technology and is the most developed, widely proven, and deployed CO_2 capture technology. Amine technologies have generally been proven to capture 95% or more of the CO_2 from the flue gas, which is highest among the post-combustion technologies. In general, the technology offered by amine technology suppliers include the same major equipment/components but differ in the proprietary solvent formulation used for their own optimal performance. Technology suppliers continue to develop new advanced solvents for use in their systems which may improve the overall performance or cost effectiveness of the technology.

4.2.1.2 Chilled Ammonia Technology

Chilled ammonia CO_2 capture is a chemical solvent-based technology which is similar to an amine system but instead uses an ammonia-based solvent. The technology is proven to capture CO_2 in the range of 85-90% from the flue gas, with higher recovery rates >95% achievable with higher capital and operating costs.

In a chilled ammonia CO_2 capture system, prior to the absorber the flue gas is cooled and pre-treated to remove SO_2, if required, ≤ 5 ppmv[19] to optimize solvent performance. This is typically achieved in a DCC or quencher. Flue gas is then sent to an absorber tower where CO_2 is absorbed by reaction with an ammonia-based solvent flowing counter-current to the flue gas. The CO_2 depleted flue gas from the absorber passes through a direct contact heater (DCH) which relies on injection of sulfuric acid (H_2SO_4) to neutralize carryover of ammonia solvent that may be emitted to the atmosphere and an ammonia-based chiller system to reduce ammonia volatility. In the DCH, flue gas is reheated using warm condensed water from the DCC to increase the temperature for adequate dispersion from stack. Ammonium bisulfate generated as byproduct from the neutralization reaction in the DCH can be sold as fertilizer.

CO_2 rich solvent is separated from the rest of the flue gas stream and is sent to a stripper column for regeneration where CO_2 is steam-stripped from the solvent. In a chilled ammonia CO_2 capture system, the solvent is regenerated at high pressure which reduces power consumption required for downstream compression and allows for the use of very low-pressure steam for solvent regeneration. The CO_2 lean solvent is recycled back to the absorber. The captured CO_2 is compressed, with minimal treatment needed (a small amount of water is a byproduct and can be treated with the plant's wastewater system).

[19] Parts per million by volume.

4.2.1.3 Enzyme Technology

Enzyme CO_2 capture technology is a chemical solvent-based technology that uses non-proprietary solvent, enhanced by the presence of a proprietary enzyme, to separate CO_2 from the flue gas. The technology is proven to capture 90% of CO_2 from the incoming flue gas. In an enzyme CO_2 capture system, prior to the absorber the flue gas is cooled to remove a large quantity of water from the flue gas. This is typically achieved in a DCC or quencher. Flue gas is then sent to an absorber tower where CO_2 is absorbed by reaction with an aqueous solution of potassium carbonate in presence of an enzyme. The enzyme accelerates the conversion of CO_2 into bicarbonate as it enters the potassium carbonate solvent and the reverse reaction (bicarbonate to CO_2) when it exits, thus reducing the size of the contacting equipment. The heat of absorption of the solvent is low. The CO_2 depleted flue gas exits the absorber through a stack located on top of the column. CO_2 rich solvent is separated from the rest of the flue gas stream and is sent to a stripper column for regeneration where residual heat / hot water is used to release CO_2 from solvent. CO_2 release in the stripper can potentially be achieved without steam using residual heat/hot water instead. The CO_2 lean solvent is recycled back to the absorber. The captured CO_2 is compressed and treated (as needed).

4.2.2 Pre-combustion Capture

Pre-combustion capture systems are applicable to fossil fuel gasification power plants (i.e., IGCC units) where coal or other solid fossil fuel (e.g., pet coke) is converted into a synthesis gas (or "syngas") by applying heat under pressure in the presence of steam and limited O_2. The product syngas contains primarily H_2 and CO – and, depending on the fuel and gasification system – some lesser amount of CO_2. The amount of CO_2 in the resulting syngas stream can be increased by "shifting" the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam ("water") with CO ("gas") to form H_2 and CO_2. The resulting CO_2 contained in the syngas is then captured before combustion of the H_2-enriched syngas for power generation in a combined cycle system. Contrary to the post-combustion capture flue gas, the IGCC syngas can contain a high volume of CO_2 and is pressurized. This allows the use of physical absorbents (e.g., Selexol™, Rectisol®) that require much less added energy to release the captured CO_2 and require less compression to get to pipeline standards.

4.2.3 Oxy-combustion

Oxy-combustion involves combusting fuel in an enriched oxygen (O_2) environment to generate useful heat and flue gas with a high concentration of CO_2. The highly concentrated CO_2 flue gas can then be treated and compressed to produce a CO_2 product stream. There are many forms in which oxy-combustion can be applied at a power plant, including retrofit of an existing facility, installation of a new system designed for oxy-combustion, or alternate technologies such as those using the Allam power cycle. Typical oxy-combustion uses a pure O_2 stream for the combustion process. This O_2 would typically be generated on-site by a cryogenic air separation unit (ASU). Cryogenic ASUs are both high in capital cost and energy consumption, alternative technologies for O_2 production are in development. Alternatively, liquid O_2 can be trucked to site from local suppliers, but this supply would require a significant number of delivery trucks and likely would also be cost-prohibitive.

For coal-fired applications, other flue gas pollutants including sulfur oxides (SOx), particulates (PM), hydrogen chloride (HCl), will still need to be treated and removed using the traditional air quality control systems. For retrofit applications, converting an existing unit to oxy-combustion will require burner modification to support oxygen combustion and flue gas recirculation (FGR) to the boiler to minimize infiltration of ambient air. As a result, nitrogen (N_2) which is approximately 80% of the air commonly used for combustion is reduced to about 4%, resulting in a flue gas volumetric flow that is approximately 75% lower than air-fired combustion. The oxy-combustion process will also result in elevated economizer outlet temperatures and flue gas with a higher moisture content. Therefore, all downstream equipment from the boiler, including the air preheaters (APHs) and existing air pollution control equipment will need to be evaluated to determine the modifications that may be required for the resulting oxy-combustion process conditions.

For most oxy-combustion applications, the CO_2 concentrated flue gas would need to be cooled and treated as necessary. This would typically involve the use of a CO_2 purification unit (CPU). In the CPU, remaining non-condensable flue gas components (N_2, O_2, and Argon) are separated from CO_2 and vented to atmosphere, either via a dedicated stack or returned to the existing stack, if feasible and applicable. The captured CO_2 product is compressed and treated (as needed).

4.2.4 Other Capture Technologies

Temperature Swing Adsorption (TSA) CO_2 capture technology is a solid sorbent-based technology that uses heat to release the CO_2 from the sorbent. There are two (2) configurations currently being developed by different suppliers: (1) continuous fluidized beds and (2) fixed beds. Both configurations of the technology have shown the ability to capture 90% of CO_2 from the incoming flue gas. The technology, although tested only at pilot-scale, is scalable with requiring multiple fluidized bed trains and/or fixed beds, depending on the design CO_2 capture rate.

For both TSA configurations, flue gas is cooled and pre-treated, as required, to optimize adsorbent performance prior to being sent to the adsorption process. CO_2 is captured on the surface pores of the adsorbent, which is regenerated using thermal energy. The CO_2 depleted flue gas exits the adsorber and passes through a particulate control system (if needed) before venting to a stack. Adsorbents have a lower heat capacity than solvents and require less energy for regeneration which allows for the use of very low-pressure stream. The captured CO_2 is compressed and treated (as needed).

Pressure Swing Adsorption (PSA) CO_2 capture technology, or in cases where pressure is lower than atmospheric pressure referred to as vacuum pressure swing adsorption (VPSA), is a solid sorbent-based technology which is specifically designed to process high concentrations of CO_2 in flue gas generated from industrial applications. For PSA CO_2 capture systems, the flue gas is cooled and pre-treated, as required, prior to being sent to the adsorption process. In the adsorption bed, CO_2 is captured on the surface pores of the sorbent. Depending on the flue gas conditions and the adsorbent properties, non-CO_2 constituents in the flue gas are also adsorbed to different extents, which may require more rigorous flue gas pre-treatment upstream of the PSA. Flue gas enters the adsorption vessel which adsorbs CO_2, and other light gases. Flue gas constituents that are not adsorbed are vented to a stack.

In the PSA process, CO_2 is desorbed by reducing the operating pressure (or creating vacuum), increasing the potential for desorption. To facilitate this the system is operated in a batch operating mode. Batch operation requires more than one (1) adsorption vessel (typically installed in pairs) and a valve switching skid to alternate between the adsorption and desorption cycles, as required. Once at capacity of the operating adsorption bed, the beds will switch operating modes. In the desorption operating mode, the vessel is depressurized to release the CO_2 rich off-gas. The CO_2 rich gas is further treated to remove other impurities (non-condensable gases), which are then recycled back to the inlet to the PSA unit(s). The purified CO_2 is compressed and treated (as needed).

Membrane CO_2 capture technology uses membranes to selectively separate CO_2 from the flue gas. Vacuum equipment located downstream of the membrane stages provide the pressure differential across the membrane that acts as the driving force for CO_2 separation from other flue gas constituents. The CO_2 capture rate of a membrane-based system can range from 60-90%; however, this rate is typically optimized for performance and cost. Higher recovery rates, greater than 90%, could be achieved but will have a significantly higher cost on a $/tonne basis than capture rates below 90%. Research is currently ongoing to improve overall capture rates without flue gas recycle to increase the inlet CO_2 concentration to the CO_2 capture island, including improved membrane design and composition to minimize capital costs and maximize permeance across the membranes.

Cryogenic CO_2 capture technology uses phase change to separate CO_2 from the flue gas. These systems use a proprietary multi-stream heat exchanger design to achieve cryogenic temperatures to generate solid CO_2. The technology demonstrations to date suggests it to be capable of capturing >95% of CO_2 from the incoming flue gas. In a cryogenic CO_2 capture system, the flue gas is dried and cooled to near ambient temperature to optimize the overall performance of the system. The flue gas is then pressurized and sent to a multi-stream heat exchanger where flue gas is further cooled to cryogenic temperatures at which CO_2 de-sublimates from gas to a solid. As flue gas is cooled to near-cryogenic temperatures, all constituents with a vapor pressure greater than the vapor pressure of CO_2 are captured along with the CO_2 but are later separated in downstream separators and warmed back to ambient temperatures to recuperate as much cooling as possible before being released through the existing or a new stack. The solid CO_2 generated from the separation process is melted to a liquid phase, pressurized, and purified (as needed) to produce a high-purity CO_2 product.

4.3 Applications of CO_2 capture for Coal-fired EGUs

There are many examples of CCS technologies being deployed to capture CO_2 across a diverse set of industries, fuel types, and processes in the U.S. and globally. Attached to this document is a spreadsheet with a list of CCS projects, including CO_2 capture projects at coal-fired EGUs (CCS facility list.xlsx). There are two large-scale CCS facilities in North America on existing coal steam electric generating units, one in Canada and the other in Texas.

The 110 MW Boundary Dam Unit 3 is located in Saskatchewan, Canada, and has operated since 2014. The unit employs integrated heat and power from the steam generating unit, and has successfully captured 5 million tons of CO_2. In the 4th quarter of 2022, the CCS unit was available 78.9% of the time and had exceeded its target availability of 75% for three consecutive quarters.[20] Similar to Petra Nova, this facility was also a retrofit of an existing facility. Boundary Dam Unit 3 had fouling and scaling issues due to excess solids (fly ash) in the system, and the project also has experienced an issue with degradation of the amine solvent that led to foaming and subsequent decreases mass and heat transfer in the absorption and regeneration columns. In summer 2021, the capture plant went offline for an extended period after issues with the CO_2 compressor. The capture plant has since gone back online and is exceeding project targets.

EPAct05-assisted capture project:

While the EPA is proposing that the capture component of CCS is adequately demonstrated based solely on the other demonstrations of CO_2 capture discussed in the preamble, adequate demonstration of CO_2 capture technology is further corroborated by CO_2 capture projects assisted by grants, loan guarantees, and Federal tax credits for "clean coal technology" authorized by the EPAct05. 80 FR 64541–42 (October 23, 2015). The EPAct05 status of referenced CCS projects is further detailed in the attached list of CCS projects (CCS facility list.xlsx).

Petra Nova is a 240 MW-equivalent capture facility that is the first application of carbon capture for coal-fired steam generators in the US at scale. This system is located at the Parish Generating Station and began operation in 2017, successfully capturing and sequestering CO_2 for several years.[21] The capture system was later put in reserve shutdown (i.e., idled) in May 2020 citing the poor economics of oil recovery at that time and may be brought back online if those economics improve. More recently, the facility has changed ownership and there are plans to restart the capture system. A final report from NETL details the success of the project and the learnings from this first-of-a-kind demonstration at scale.[22] The project used Mitsubishi Heavy Industry's proprietary KM-CDR Process®, a process that is

[20] SaskPower, BD4 Status Update: Q4 2022. Available at https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project.
[21] W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March, 2020). Available at https://www.osti.gov/servlets/purl/1608572.
[22] Ibid.

similar to an amine-based solvent process but that uses a proprietary solvent and is optimized for CO_2 capture from a coal-fired generator's flue gas. During the plant's three-year demonstration period, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR. The project experienced some technical challenges including leaking process heat exchangers, excess solids and slurry carryover in the flue gas leading to fouling and scaling of downstream equipment, and corrosion and scaling in the components of the CO_2 compressor. Collectively, unplanned outages at the capture plant accounted for less than one-third of facility unplanned outages, with the remainder due to the auxiliary combined cycle unit, the boiler unit, weather, or the ability of the sequestration site to accept CO_2 for EOR. Despite these challenges outages decreased and capture rates increased year-on-year.

4.4 Early-stage CCS Projects at Coal-Fired Steam EGUs

There are at least a half-dozen projects currently in the early stages of assessing the merits of retrofitting existing coal steam EGUs with CCS technology. These efforts have commenced with Front-end Engineering and Design (FEED) studies to gain a better understanding of engineering requirements and overall feasibility. These studies have benefited from research and funding opportunities from DOE, which oversees the Federal Government's R&D efforts for power powerplants. The recently enacted legislation provides additional funding opportunities for such assessments and studies. While the below examples all pertain to coal-fired power plant CCS retrofits, the lessons learned and cost reductions achieved are relevant more broadly, including to the application of CCS to existing gas facilities.

The Basin Electric Dry Fork Station, located in Wyoming, has completed a FEED study to assess a membrane-based CO_2 Capture Process.[23] This study is being undertaken by Membrane Technology and Research, Sargent & Lundy, Trimeric Corporation, in cooperation with Basin Electric Power Cooperative, and Electric Power Research Institute. The study evaluated the retrofit of MTR's membrane-based post-combustion carbon dioxide capture technology to the BEPC Dry Fork Station (DFS) Unit 1. The capture plant is designed to treat the entire flue gas flow and is estimated that this system will capture 6,560 tonnes of CO_2 per day.[24]

Prairie State Generating Station, located in Illinois, has conducted a full-scale FEED study for retrofitting the Prairie State Generating Station[25] (Unit 2) with a capture system using Mitsubishi Heavy Industries Post-Combustion CO_2 Capture Technology.[26] This system uses the proven and demonstrated process employed at Petra Nova facility in Texas.

There are several other FEED studies underway at existing facilities, supported by DOE, that are expected to be completed soon. Nebraska Public Power District's Gerald Gentleman Station in Nebraska will soon complete a FEED study for the installation of an advanced CCS system using technology from Ion Engineering.[27] This process employs a solvent-based CO_2 capture technology by utilizing their ICE-21 solvent that offers key technological advantages including greater reduction in energy, lower

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[23] Full Scale Carbon Capture FEED Study for Dry Fork Station Unit 1, S&L Summary Report (April, 2022). Available at *https://www.osti.gov/servlets/purl/1897679*.

[24] *https://www.basinelectric.com/News-Center/news-releases/carbon-capture-project-at-dry-fork-station-begins-phase-3-testing*.

[25] *https://prairiestateenergycampus.com/*.

[26] 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 (August, 2022). Available at *https://www.osti.gov/servlets/purl/1879443*.

[27] *https://www.netl.doe.gov/node/7185* and *https://www.nppd.com/powering-nebraska/innovation/carbon-capture*.

emissions, faster solvent kinetics, and less solvent degradation to minimize the need for solvent replacement.[28]

The Diamond Vault project (Lena, LA)[29] is a recently announced project for a CCS retrofit at the Brame Energy Center, which is a facility burning petroleum coke and coal. The Louisiana Department of Economic Development will oversee a front-end engineering and design study for a full-scale carbon capture retrofit at Cleco's Brame Energy Center Madison Unit 3 plant.[30] The project is expected to begin construction in 2025 and begin commercial operation in 2028.[31]

Project Tundra[32] is an announced CCS retrofit project at the Milton R. Young Station in North Dakota, owned by Minnkota Power Cooperative. This FEED study will inform the retrofit of a post-combustion capture system at the Milton R. Young Station in North Dakota. The project will use Fluor's Econamine FG Plus technology, an amine-based process specialized for the removal of CO_2 from low-pressure, oxygen-containing gas.

DOE further announced[33] on May 5, 2023, the selection of additional CCS retrofit projects at existing coal-fired power plants to be awarded funding for FEED studies. This includes a FEED study for post-combustion CCS at Duke Energy's coal- and natural gas-fired integrated gasification combined cycle facility in Edwardsport, Indiana, a FEED study for post-combustion solvent-based CCS from the coal-fired Four Corners Power Plant on the Navajo Nation to be capable of capturing more than 10 million metric tons of CO_2 per year, and a FEED study for Post-combustion solvent-based CCS at the coal-fired steam generating unit Dallman 4 at City Water, Light and Power in Springfield, Illinois to capture an estimated 2 million metric tons of CO_2 per year with transport and geologic storage to a site in the Illinois Storage Corridor.

4.5 Funding and Incentives

There are many Federal programs, grants, and R&D efforts and funding opportunities that support CCS technology, which are jump-starting deployment efforts. Perhaps the most significant effects for the power sector will result from the Inflation Reduction Act (IRA), which was signed into law on August 16, 2022. With billions of dollars in investments in the transition to clean energy, the IRA promotes investment toward low- and non-GHG emitting generation. The IRA's provisions include a broad array of tax credits, loan guarantees, and public investment programs that incent reductions in GHGs across the economy. In particular, the provisions aim to reduce GHG emissions from the fossil fuel-fired generating sources that are the subjects of this proposal, with tax credits for use of CCS and for hydrogen production and use that provide pathways for the use of fossil fuels as part of a low-carbon electricity grid.

The IRA increased the tax credit incentives for capturing and storing CO_2, including from coal-fired steam generating units and natural gas-fired stationary combustion turbines. The increase in credit values, found in section 13104 (which revises Internal Revenue Code (IRC) section 45Q), is 70 percent, equaling \$85/metric ton for CO_2 captured and securely stored in geologic formations and \$60/metric ton

[28] *https://www.nppd.com/press-releases/department-of-energy-awards-funding-for-phase-ii-of-carbon-capture-study-for-gentleman-station*.
[29] *https://www.cleco.com/media/press-releases/detail/2022/04/11/cleco-power-launches-major-louisiana-economic-initiative-project-diamond-vault*.
[30] *https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas*.
[31] *https://www.cleco.com/media/press-releases/detail/2022/04/11/cleco-power-launches-major-louisiana-economic-initiative-project-diamond-vault*.
[32] *https://www.projecttundrand.com/*.
[33] *https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies*

for CO_2 captured and utilized or securely stored in conjunction with enhanced oil recovery (EOR), with the full value only available for projects meeting prevailing wage and apprenticeship requirements. The CCS incentives include 12 years of credits that can be claimed at the higher credit value beginning in 2023 for qualifying projects. Certain tax-exempt entities, such as tax-exempt co-ops, may use direct pay options for the full 12 years of the credit stream. Direct-pay options enhance the tax credits by enabling developers to monetize the credits directly as cash refunds, rather than through tax equity markets. Entities that are not tax-exempt may transfer credits to unrelated taxpayers, enabling direct monetization of the credits again without depending on tax equity markets. These entities are also eligible for direct pay for the initial 5 years of the project. Specifically for the power sector, the IRA requires that a qualifying carbon capture facility have a CO_2 capture design capacity of not less than 75 percent of the baseline CO_2 production of the unit and that construction must begin before January 1, 2033.

The Infrastructure Investment and Jobs Act (IIJA, also known as the Bipartisan Infrastructure Law), allocates more than $70 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-carbon fuels. The IIJA allocated $21.5 billion to fund new programs to support the development, demonstration, and deployment of clean energy technologies, such as $8 billion for the development of regional clean hydrogen hubs. Other clean energy technologies with IIJA funding include carbon capture, grid-scale energy storage, and advanced nuclear reactors. States, tribes, local communities, utilities, and others are eligible to receive funding. Most of these research programs are housed and administered by the DOE.[34] There have been 24 funding announcements since 2021.

For example, in 2022 DOE announced up to $92 million to design regional CO_2 pipeline networks to safely transport captured CO_2 from key sources to centralized locations. Projects will focus on carbon transport costs, transport network configurations, and technical and commercial considerations that support broad efforts to develop and deploy carbon capture, conversion, and storage at commercial scale.[35] In addition, a $2.25 billion funding announcement for the development of new and expanded large-scale CCS storage projects was also announced.[36] Projects will focus on detailed site characterization, permitting, and construction stages of project development under CarbonSAFE. This funding is provided from the Bipartisan Infrastructure Law Section 40305.

4.6 CO_2 Transportation and Storage

Geologic sequestration is technically feasible, widely available, and is being actively done today in the United States. Using independent analyses of potential availability of geologic sequestration capacity in the United States conducted by the Department of Energy (DOE) and United States Geological Survey (USGS), data reported to EPA through the Greenhouse Gas Reporting Program (GHGRP) subparts UU and RR, and additional industry research and data, EPA performed a geographic analysis to examine areas of the country with sequestration potential in deep saline formations, oil and gas reservoirs, and unmineable coal seams. Within this analysis, EPA also layered information on existing

[34] *https://www.energy.gov/fecm/past-and-current-funding*.

[35] DOE Funding Notice: Bipartisan Infrastructure Law: Carbon Capture Technology Program, Front-End Engineering Design for Carbon Dioxide (CO2) Transport. Available at *https://www.energy.gov/fecm/funding-notice-bipartisan-infrastructure-law-carbon-capture-technology-program-front-end*.

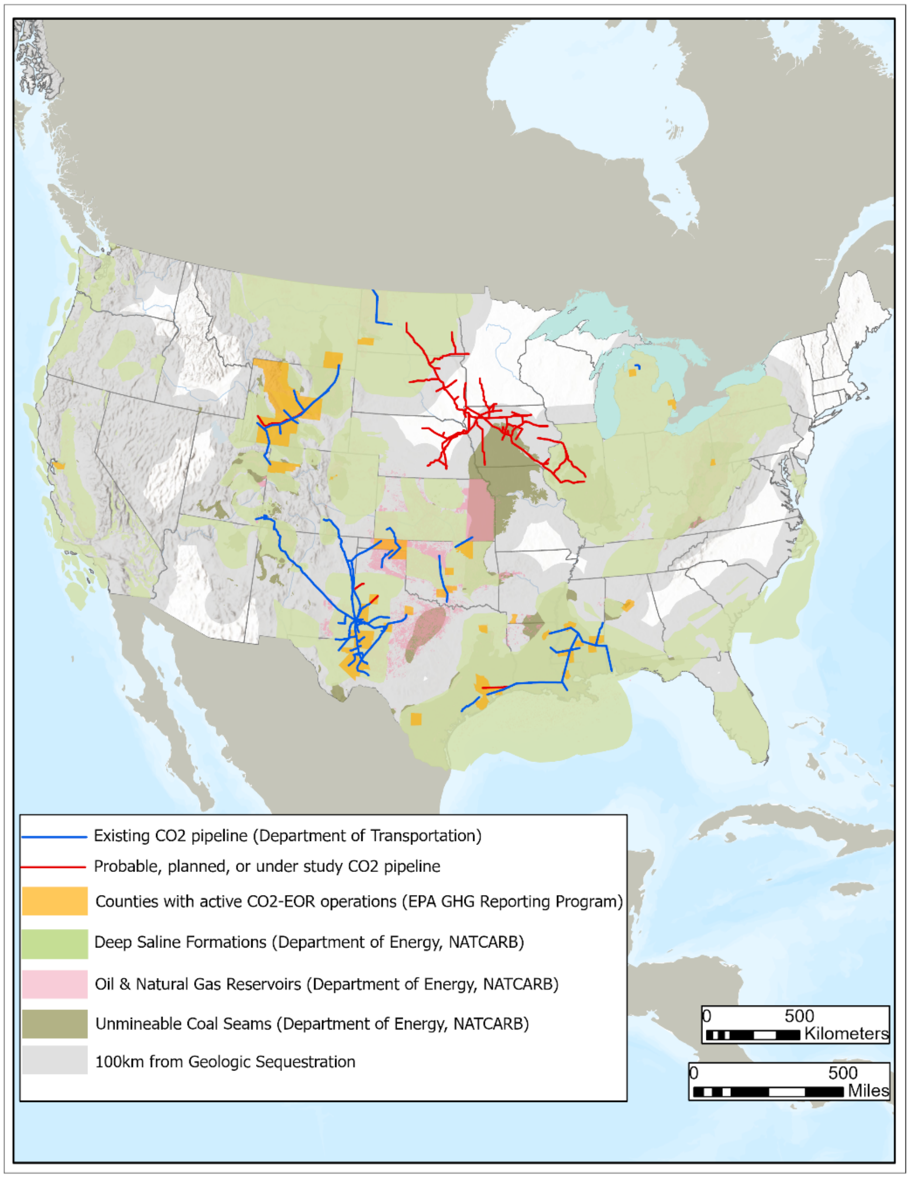
[36] DOE Funding Notice: Carbon Storage Validation and Testing. Available at *https://www.energy.gov/fecm/funding-notice-carbon-storage-validation-and-testing*.

and probable, planned, or under study CO_2 pipelines and areas within a 100-km (62-mile) distance from locations with sequestration potential.[37]

Based on the Agency's analysis, Figure 1 provides a geographic overview of the sequestration potential in in deep saline formations, oil and gas reservoirs, and unmineable coal seams within the United States. This geographic overview does not include additional resource assessments needed to determine sequestration potential in regions that have not been thoroughly assessed, including for other storage types, such as in shales or basalt formations, or other geographic regions such as offshore state waters. Forty-three states have onshore and/or offshore geographic availability or access via pipeline for geologic CO_2 sequestration potential.[38] Seven states, including Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and Hawaii,[39] do not have geologic sequestration potential or are not within 100-km of areas with potential. The sections below describe the methodology and sources used for development of this map. The discussion below regarding CO_2 transportation and storage is, in general, applicable to new and existing fossil fuel-fired EGUs, including new stationary combustion turbine EGUs, existing fossil fuel-fired stationary combustion turbine EGUs, and existing fossil fuel-fired stationary combustion turbine EGUs. Also attached to this document is a spreadsheet with a list of CCS projects, including CO_2 transport and sequestration projects (CCS facility list.xlsx).

[37] The distance of 100-km is consistent with the assumptions underlying the DOE National Energy Technology Laboratory (NETL) cost estimates for transporting CO_2 by pipeline.
[38] Alaska is not shown in Figure 1. Alaska has deep saline formation storage capacity, geology amenable to EOR operations, and potential geologic storage capacity in unmineable coal seams.
[39] Hawaii is not shown in Figure 1. Hawaii does not have geologic sequestration potential identified by NETL.

Figure 1. Geologic Sequestration Potential in the Continental United States[40]



4.6.1 CO_2 Transport Infrastructure

Pipelines are the most commonly used, economical, and efficient means of transporting large quantities of CO_2.[41] CO_2 has been transported via pipelines in the United States for nearly 60 years. Over this time, the design, construction, operation, and safety requirements for CO_2 pipelines have been

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[40] Sources used in development of the map include: U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: https://www.netl.doe.gov/research/coal/carbon-storage/atlasv; EPA. Greenhouse Gas Reporting Program (GHGRP) Subparts UU and RR. 2021. Available online at: https://ghgdata.epa.gov/ghgp/main.do; U.S. DOT Pipeline and Hazardous Materials Safety Administration. Hazardous Liquid Annual Data. 2021. Available online at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. Sources of information for proposed pipelines are listed in Section 4.6.1.2.

[41] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 36.

proven, and the U.S. CO_2 pipeline network has been safely used and expanded. Many miles of pipelines are currently under construction or planned, further expanding the network in the United States.

4.6.1.1 Existing Pipelines

The Pipeline Hazardous Materials Safety Administration (PHMSA) cited 5,339 miles of CO_2 pipelines in operation in the United States in 2021.[42] Since 2011 the number of pipeline miles has increased by 13 percent.

CO_2 pipelines are currently operated in 11 states to support transportation of natural and anthropogenic CO_2. The Cortez pipeline is the longest CO_2 pipeline and begins at the McElmo Dome CO_2 field in southwest Colorado and traverses 502 miles through New Mexico ending at the Denver City, Texas CO_2 Hub, where it connects with several other CO_2 pipelines. The Cortez pipeline was constructed in 1982 and is capable of transporting 1.5 billion cubic feet of CO_2 per day.[43] Other large pipelines connect natural CO_2 sources in south central Colorado, northeast New Mexico, and Mississippi to oil fields in Texas, Oklahoma, New Mexico, Utah, and Louisiana.

Anthropogenic CO_2 from natural gas processing plants, fertilizer plants, and ethanol facilities, is also transported through a series of pipelines that are generally shorter than pipelines from natural CO_2 source areas.[44] Large pipelines in Wyoming, Texas, and Louisiana carry anthropogenic gas from gas plants and refineries to EOR projects. Many smaller pipelines carry gas from anthropogenic sources to central distribution facilities or to EOR projects, including the examples below:

- The Terrell Gas facility (formerly Val Verde) in Texas supplies CO_2 for EOR projects in the Permian Basin through an 82 mile pipeline.
- A fertilizer plant in Coffeyville, Kansas supplies CO_2 via a 68 mile dedicated pipeline to the North Burbank Unit in northeast Oklahoma.
- Two separate facilities capturing CO_2, a fertilizer plant in Borger, TX and an ethanol plant in Liberal, KS, supply CO_2 to several EOR projects in Oklahoma and Texas via 173 miles of dedicated pipelines.

4.6.1.2 Planned or Announced Pipelines

There are a number of CO_2 pipeline projects in the United States that are likely to be developed to meet growing demand for CO_2 and increased interest in CO_2 utilization and sequestration. As a part of the availability analysis, EPA reviewed documented progress and information related to planned or announced pipelines; some of which are regionally significant, publicized projects. This includes any pipelines that are under National Environmental Policy Act (NEPA) review, have been announced publicly, or are identified as part of specific capture projects. The pipelines identified are listed in Table 1 and represented in EPA's availability analysis. Data for planned pipelines is not readily available from a single source, so new capture and sequestration/use projects were identified and reviewed to determine if a pipeline was part of the proposed plan. The analysis used a combination of CCS project databases from NETL, Global CCS Institute (GCCSI), Wyoming Enhanced Oil Recovery Institute (EORI), and California Low Carbon Fuel Standard (LCFS), and selected Bureau of Land Management (BLM) NEPA Actions databases.

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[42] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2021. Available online at: *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids*.

[43] Kinder Morgan, "CO_2 Pipelines". Accessed 2023. Available online at: https://www.kindermorgan.com/Operations/CO2/Index#tabs-co2_pipelines

[44] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

Approximately 3,895 miles of new planned CO_2 pipelines were identified, as outlined in Table 1 below and on Figure 1 above, increasing the total potential pipeline network to 9,234 miles, an increase of 73% over today. The vast majority of the new pipeline miles are related to two new projects linking multiple ethanol plants in the Midwest to sequestration sites in Illinois and North Dakota.

Table 3. Planned or Announced CO_2 Pipelines Included

Pipeline Name	States	Miles	Data Sources
Midwest Carbon Express	ND, IA, NE, MN, SD	2067	https://summitcarbonsolutions.com/project-footprint/
Heartland Greenway Phase 1A + 1B	NE, IA, SD, MN, IL	1302	https://heartlandgreenway.com/
Mt. Simon Hub	IA, IL	280	https://wolfcarbonsolutions.com/mt-simon-hub/
Unnamed, Ethanol plants in Plainview and Hereford, Texas	TX	48 + 35	Submission to CARB for LCFS https://ww2.arb.ca.gov/
Lost Creek to Lost Cabin Interconnect (Riley Ridge)	WY	73	Wyoming Pipeline Authority; 5/2/2019 https://www.wyopipeline.com/wp-content/uploads/2019/05/New-Wyoming-Pipeline-and-Associated-Infrastructure-Projects-052019.pdf
Conroe to Green Pipeline	TX	90	Denbury Form 8-K; 9/22/2020 https://www.sec.gov/Archives/edgar/data/945764/000094576420000156/den-20200922x8kpresent.pdf

4.6.1.3 Other Modes of CO_2 Transport

Transportation of CO_2 via pipeline is the most viable and cost-effective method at the scale needed for sequestration of captured EGU CO_2 emissions. However, CO_2 can also be transported via ship, road tanker, or rail tank cars where pipelines are not available or when smaller quantities of CO_2 need to be transported. Transport of liquified food-grade CO_2 by ship takes place currently at a small scale for food and beverage applications,[45] with the first ship intended specifically for the transport of CO_2

[45] Al Baroudi, et. al. (2021). A Review of Large-Scale CO_2 Shipping and Marine Emissions Management for Carbon Capture, Utilisation, and Storage. *Applied Energy*. *https://www.sciencedirect.com/science/article/pii/S0306261921000684.*

produced by CCUS currently under construction.[46] Liquified CO_2 has many of the same properties as liquified natural gas, and today onshore facilities exist that load and unload liquified natural gas and liquified petroleum gas from ship tankers in large quantities.[47] Additionally, transport of CO_2 by truck is done at project sites currently to move CO_2 from where it is captured to nearby storage and can provide a flexible modular solution for short distance transport.[48] In 2020, 1,300 rail tank cars, each capable of moving approximately 22,000 gallons, provided 11,287 shipments of CO_2 in North America.[49]

4.6.2 Geologic Sequestration

CO_2 may be sequestered in different types of geologic formations and remain stored via different physical and chemical trapping mechanisms. Types of formations, all of which EPA assessed, include deep saline formations, oil and gas reservoirs (depleted and active (i.e., EOR)), and unmineable coal seams. Within these formations, CO_2 may be trapped through a combination of mechanisms including: (1) structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).

To assess the availability of geologic sequestration capacity across the United States, EPA compiled and analyzed information from a few key resources, including the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) and its Carbon Utilization and Sequestration Atlas (NETL Atlas)[50] and the USGS's national assessment of geologic carbon dioxide storage resources.[51] Neither the NETL methodology or the USGS storage estimates include chemical trapping (mineralization or dissolution) or potential storage in shales or basalt formations. Data from EPA's GHGRP (subparts UU and RR) was used to supplement the DOE and USGS assessments and produce the representation of potential sequestration availability within Figure 1.

DOE estimates are compiled in the DOE's NATCARB using volumetric models and published in the NETL Atlas.[52] The resource estimates in the NETL Atlas were developed to provide an assessment of CO_2 geologic sequestration potential across the United States, including in deep saline formations, oil and gas reservoirs, and unmineable coal seams. The latest version of the Atlas, published in September 2015, includes the most current and best available estimates of potential geologic sequestration capacity determined by a methodology applied consistently across all seven

[46] Carbon Capture Magazine. (2022). Mitsubishi to Build World's First Ship for Liquid CO_2 Transport. https://carboncapturemagazine.com/articles/47/mitsubishi-to-build-worlds-first-ship-for-liquid-co2-transport.

[47] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[48] Global CCS Institute. (2018). Fact Sheet – Transporting CO_2. https://www.globalccsinstitute.com/wp-content/uploads/2018/12/Global-CCS-Institute-Fact-Sheet_Transporting-CO2-1.pdf.

[49] U.S. Department of Transportation, Federal Railroad Administration Hazardous Materials Division. (2020). CO_2 by Rail – North American Overview. https://usea.org/sites/default/files/event-/Maday%20-%202022%20CO2%20Freight%20Transportation%20Workshop.pdf.

[50] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

[51] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, *National assessment of geologic carbon dioxide storage resources – Summary: U.S. Geological Survey Factsheet 2013-3020*. Available online at: *http://pubs.usgs.gov/fs/2013/3020/*.

[52] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

of the DOE Regional Carbon Sequestration Partnerships (RCSPs). The methodology defines a CO_2 storage resource estimate as the volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. DOE's assessment focuses on the potential physical constraints for sequestering CO_2; it does not include economic or other constraints. The NETL Atlas presents low, medium, and high geologic sequestration capacity estimates.

Estimates based on DOE studies indicate that areas of the United States with appropriate geology have a sequestration potential of 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, oil and gas reservoirs, and unmineable coal seams.[53] For the low estimate, deep saline formations constitute the largest potential for sequestration, 2,200 billion metric tons, or 90 percent of total potential. For comparison, this amount is 1,500 times the 2020 annual U.S. electricity generation- related CO_2 emissions of 1,439 million metric tons.[54] Table 2 shows low and high total CO_2 storage resource estimates by state based on analysis by NETL.

Table 4. Total CO_2 Storage Resource, as Presented in the 2015 NETL Carbon Storage Atlas[55]

	Billion Metric Tons*	
State	**Low Estimate**	**High Estimate**
Alabama	122.20	649.16
Alaska	8.64	19.75
Arizona	0.11	1.15
Arkansas	6.07	63.70
California	33.89	423.70
Colorado	35.28	357.34
Connecticut	Not Assessed By NETL	Not Assessed By NETL
Delaware	0.04	0.04
District Of Columbia	Not Assessed By NETL	Not Assessed By NETL
Florida	102.65	554.95
Georgia	145.34	159.05
Hawaii	Not Assessed By NETL	Not Assessed By NETL
Idaho	0.04	0.39
Illinois	21.23	216.28
Indiana	38.25	128.76
Iowa	0.00	0.01
Kansas	10.88	86.34
Kentucky	15.91	113.61
Louisiana	162.78	2,102.43
Maine	0.00	0.00
Maryland	1.86	1.93
Massachusetts	0.00	0.00

[53] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.
[54] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020*. Available online at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020*.
[55] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

	Billion Metric Tons*	
State	**Low Estimate**	**High Estimate**
Michigan	31.72	66.52
Minnesota	0.00	0.00
Mississippi	144.74	1,185.10
Missouri	0.02	0.30
Montana	98.69	858.15
Nebraska	23.66	111.98
Nevada	Not Assessed By NETL	Not Assessed By NETL
New Hampshire	Not Assessed By NETL	Not Assessed By NETL
New Jersey	0.00	0.00
New Mexico	42.76	359.09
New York	4.42	4.52
North Carolina	1.34	18.39
North Dakota	72.85	237.44
Offshore Federal Only	490.93	6,454.00
Ohio	10.68	12.00
Oklahoma	23.12	211.65
Oregon	6.81	93.70
Pennsylvania	18.41	20.06
Rhode Island	Not Assessed By NETL	Not Assessed By NETL
South Carolina	30.10	34.18
South Dakota	3.70	12.16
Tennessee	0.50	4.63
Texas	479.36	4,373.25
Utah	23.95	242.13
Vermont	Not Assessed By NETL	Not Assessed By NETL
Virginia	0.43	2.91
Washington	36.62	496.74
West Virginia	17.49	29.61
Wisconsin	0.00	0.00
Wyoming	153.12	1,547.75
U.S. Total	**2,421**	**21,255**

**States with a "zero" value represent estimates of minimal CO_2 storage resource. States that have not yet been assessed by DOE-NETL have been identified.*

Further evidence of the widespread availability of CO_2 sequestration reserves in the United States comes from the Department of Interior's USGS, which has completed a comprehensive evaluation of the technically accessible resources for carbon sequestration for 36 sedimentary basins in the onshore areas and state waters of the United States.[56] The USGS methodology differs from the NETL methodology in that it does not include an estimate of the CO_2 storage potential in "unmineable coal seams", or offshore federal waters, and does not consider EOR.

[56] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, *National assessment of geologic carbon dioxide storage resources – Summary: U.S. Geological Survey Factsheet 2013-3020*. Available online at: *http://pubs.usgs.gov/fs/2013/3020/*.

The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the United States.[57] In 2013, the USGS completed its evaluation of the technically accessible sequestration for CO_2 in U.S. onshore areas and state waters using probabilistic assessment. The USGS methodology defines technically accessible storage as the mass of CO_2 that can be stored in the pore volume of the storage formation taking into account present-day geologic knowledge and engineering practice and experience. The assessment used a geology-based examination of all sedimentary basins in the onshore and state waters area of the United States that contain potential storage formations that meet specific criteria including depth (3,000 feet to 13,000 feet deep), thick regional seals, and saline formation water (total dissolved solids greater than 10,000 milligrams per liter). The storage estimates were divided into buoyant trapping, where CO_2 can be trapped in structural or stratigraphic closures, and residual trapping, where CO_2 can be held in place by capillary pore pressures in areas outside of buoyant traps. Probability percentiles were calculated representing the 5-, 50-, and 95-percent probabilities, respectively, that the true storage resource is less than the value presented. A mean value of storage for each storage type was also calculated. Storage in oil and gas formations was considered in the assessment, however, only the amount of CO_2 that could replace the volume of known hydrocarbon production was assessed and quantified. This represents a conservative estimate because it does not include assessment of sequestration associated with EOR. Several basins, including areas of California, Washington, Oregon, and Idaho were not assessed by USGS. Storage estimates were reduced to account for potential USDWs that may be present. A summary of the methodology and results of the USGS assessment can be found at http://pubs.usgs.gov/circ/1386/.

In addition to the 3,000 billion metric tons of subsurface CO_2 sequestration potential from buoyant and residual trapping, USGS estimates another 11 billion metric tons from known oil and gas recovery replacement. Storage resources are dominated by medium permeability residual trapping resources, which accounts for 89 percent of the total resources. The Coastal Plains Region of the United States contains the largest storage resource of any region. Within the Coastal Plains Region, the resources from the U.S. Gulf Coast area represent 59 percent of the national CO_2 storage capacity.

While the NETL and USGS characterize potential storage, site-specific technical, regulatory, and economic considerations will ultimately factor into the attractiveness of a given storage resource for a particular project. Additionally, the various types of geologic formations assessed have been characterized to varying degrees. That is, there is more uncertainty in the assessment of certain types of formations as compared to others.

Overall, EPA found there are 43 states that have potential for onshore or offshore geologic sequestration in deep saline formations, oil and gas reservoirs, unmineable coal seams, or EOR, or access to sequestration via pipeline (within 100-km distance). At least 37 states have geologic characteristics that are amenable to deep saline sequestration, and an additional 6 states are within 100 kilometers (62 miles) of potentially amenable deep saline formations in either onshore or offshore locations.[58] Unmineable coal seams have a sequestration potential of 54 billion metric tons of CO_2, or 2 percent of total potential in the United States, and are located in 22 states.

4.6.3 Enhanced Oil Recovery

Enhanced oil recovery (EOR) is a technique that is used to increase the production of oil, where the CO_2 injected into an oil reservoir helps mobilize the remaining oil to make it more amenable and

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[57] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, *National assessment of geologic carbon dioxide storage resources – Summary: U.S. Geological Survey Factsheet 2013-3020*. Available online at: *http://pubs.usgs.gov/fs/2013/3020/.*

[58] Alaska has deep saline formation storage capacity, geology amenable to EOR operations, and potential GS capacity in unmineable coal seams.

economical for recovery. In doing so, CO_2 can remain in the reservoir and become incidentally sequestered.

EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has nearly 60 years of experience with EOR. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure geologic sequestration that can be used for deployment of CCS across geographically diverse areas.

EPA collects data on EOR through the GHGRP from subparts PP (Suppliers of Carbon Dioxide), UU (Injection of Carbon Dioxide), and RR (Geologic Sequestration of Carbon Dioxide). While GHGRP subparts PP and UU require data collection and reporting for amounts of CO_2 supplied for EOR and injected at EOR facilities, EOR facilities can chose to opt into GHGRP subpart RR. GHGRP subpart RR requires a site-specific MRV plan and facility-specific annual reporting of the amount of CO_2 sequestered. EPA recently proposed the new GHGRP subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), for EOR facilities to report geologic sequestration of CO_2 in association with EOR using the ISO 27916 standard (ISO standard designated as CSA/ANSI ISO 27916:2019, Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2–EOR)). This ISO 27916 standard requires and Operations Management Plan that sets forth the operator's approaches for containment assurance and monitoring and provides the level of detail on operations and reporting that are comparable to a GHGRP subpart RR MRV plan.

GHGRP data indicate that 35.1 million metric tons of CO_2 were used for CO_2-EOR in 2021.[59] Approximately 60 percent of the total CO_2 supplied was produced from natural (geologic) CO_2 sources and approximately 40 percent was captured from anthropogenic sources. Currently, 14 states have active EOR operations, and most have developed an extensive CO_2 infrastructure, including pipelines, to support the continued operation and growth of EOR. The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and Southeast New Mexico. States where EOR is active also include Alabama, Arkansas, California, Colorado, Louisiana, Michigan, Mississippi, Montana, North Dakota, Oklahoma, Utah, and Wyoming. All states with active EOR operations also have areas that are amenable to deep saline sequestration in either onshore or offshore locations.

The amount of CO_2 that can be injected for an EOR project and the duration of operations are of similar magnitude to the duration and volume of CO_2 that is expected to be captured from fossil fuel-fired EGUs. The volume of CO_2 used in EOR operations can be large (*e.g.*, 55 million tons of CO_2 were stored in the Scurry Area Canyon Reef Operators (SACROC) unit in the Permian Basin over 35 years), and operations at a single oil field may last for decades, injecting into multiple parts of the field.[60]

Through the GHGRP, the Agency has data about the use and sequestration of CO_2 in EOR. GHGRP data are integrated into the availability assessment in Figure 1.[61] Approximately 60 percent of the total CO_2 supplied was produced from natural (geologic) CO_2 sources and approximately 40 percent was captured from anthropogenic sources. Furthermore, data from subpart RR facilities, many of which are conducting EOR, indicate that in 2021, 6.9 million metric tons of CO_2 were sequestered.[62] All states with active EOR operations also have areas that are amenable to deep saline sequestration in either onshore or offshore locations.

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[59] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.
[60] Han, W. S., *et. al.* "Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection." American Journal of Science 310. (2010): 282–324.
[61] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.
[62] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

4.7 Evaluation of CCS as BSER for EGUs

There are a variety of data sources and assessments for that inform CCS as BSER for existing coal-fired EGUs, new baseload natural gas-fired combustion turbines, and large baseload existing natural gas-fired combustion turbines.[63] These include feasibility and design studies, project development experience at sites that have deployed CCS (for the electric sector and other industries), and engineering assessments of CCS technology by both the public and private sector. The technology has been studied, examined, and tested for decades and it has reached a point in its development where it is adequately demonstrated and commercially available. Although deploying CCS technology is not simple and requires significant resources and engineering, it can feasibly be deployed on existing coal-steam sources and new and existing natural gas-fired combustion turbines.

It is important to note that cost estimates for CCS deployment can vary dependent upon a host of factors. Each affected source has some unique characteristics that may result in different cost calculations and estimates based on unique circumstances and conditions. The assessment and data provided here and in the *GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines* TSD is representative and indicative of what the technology can be reasonably expected to cost, and is used to inform BSER. The estimates are not meant to be cost determination for each EGU, but are used more broadly to assess and inform policy choices.

4.7.1 Timing

Deployment of CCS technology at EGUs involves a project schedule that can be completed in roughly five years. For affected sources who choose to implement CCS, the project will involve several phases, many of which can occur concurrently and simultaneously. The project planning for capture systems involves two major phases; project design/development, and project implementation. Additional project planning for transport and storage of CCS is also needed, which includes potential deployment of infrastructure for post-capture transport and storage of CO_2 captured into appropriately designated locations.

There are currently significant incentives for deployment of CCS technology that were part of recent landmark legislation, the Inflation Reduction Act (IRA). The additional economic incentives are important for establishing that the cost of CCS is reasonable, and an appropriate BSER. This fact is highly motivating, as sources consider how best to plan long-term operations, dispatch, and meeting overall electric demand. The other component to timing of CCS is regulatory motivation; there have been no Federal standards for CO_2 emissions for existing power plants, despite several efforts over the past ten years. Hence, timing considerations will be fundamentally shifted and advanced in response to a regulatory impetus.

Historically, consideration of CCS technology on EGUs has been done in response to economic incentives (both market incentives and government subsidies), and voluntary in nature. These efforts have helped to advance the state of technology and its readiness for deployment, yet they were not motivated or driven by any emission requirement or standard, and thus timeframes for researching, assessing, and deploying the technology were done absent any specific and legally binding requirements. Thus, the timelines (up to this point) never contemplated rapid deployment of the technology, since it was not legally required or mandated for EGUs. This proposed action seeks to apply such mandates, whereby sources expedite (where feasible) the scheduled deployment of CCS technology in a reasonable manner in order to meet the timing requirements of this action.

The first phase of CCS capture system project development is the design and development phase, which involves several components. First is a feasibility evaluation to determine the technical and

[63] See the *GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines* TSD in Docket ID No. EPA-HQ-OAR-2023-0072 for a detailed exploration of CCS for combustion turbines.

economic aspects of a potential retrofit. FEED studies are then completed for a more thorough evaluation. EPA believes these steps can be consolidated and expedited in response to this proposed action. Additional steps in this phase include engaging in technical and commercial arrangements, arranging project financing, meaningful public engagement, baseline environmental monitoring and permitting. Each of these individual steps need not be in a sequential, and many of these actions can be planned well in advance, such that there can be significant time savings across these project planning steps.

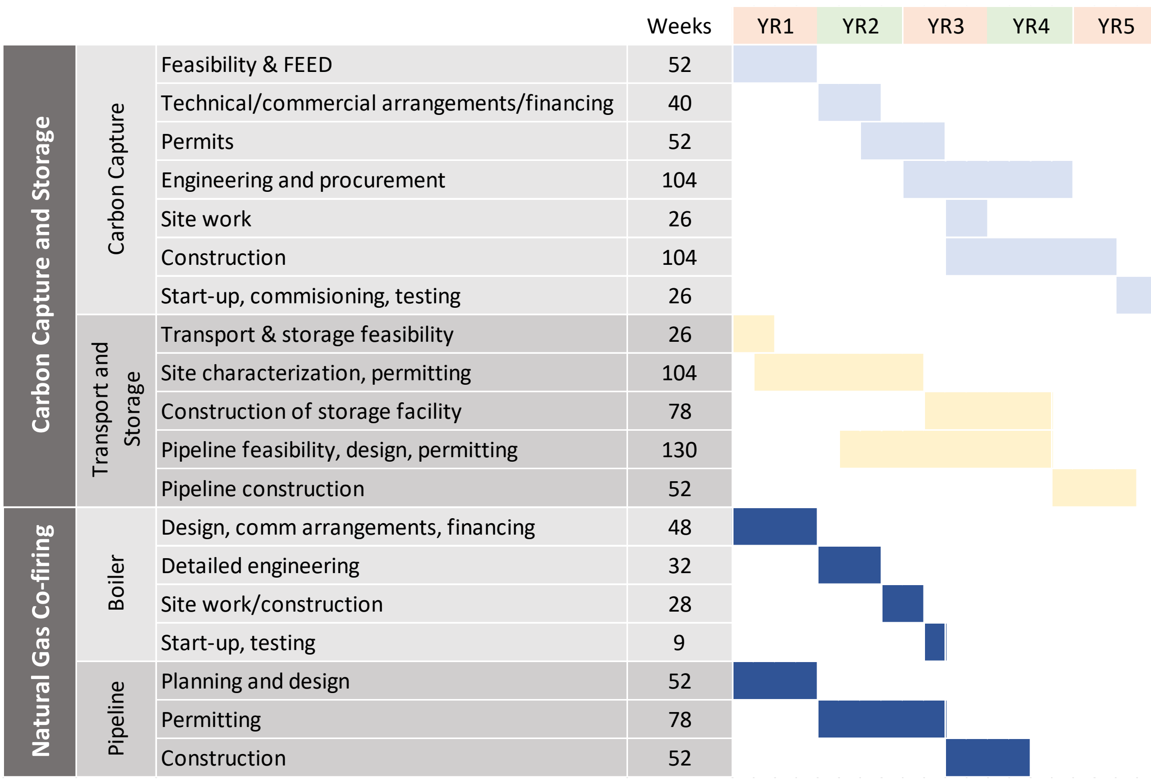
The second phase of CCS capture system deployment is the project implementation phase. The longest aspects of this phase are the more detailed engineering and procurement that needs to be undertaken, the actual construction of the system and ongoing meaningful public engagement. Site work and preparation is also needed during this phase as construction launches. These steps are non-sequential, and together with proper planning, can be conducted over a timeframe of roughly three years.

Deployment of necessary equipment, infrastructure, and technology for transport and storage of the captured CO_2 can be done concurrently with deployment of the capture system. Most aspects of the CO_2 transport and storage design, engineering, and construction are similar to the CCS capture system. Feasibility work occurs first, with site characterization and permitting of storage area(s) occuring next. These steps are estimated to take roughly one to two years, based on site-specific circumstances.[64] With site characterization progressing and site permitting initiated, design and engineering work for the related pipeline (if new pipeline is needed) can then begin. Construction at the site and for the pipeline will follow. These steps for transport and storage projects are estimated to take four years, and can mostly happen concurrently with each other and with installation of the capture system.[65,] Transportation and storage will also require meaningful public engagement and environmental monitoring. [66]

There are many site-specific considerations to individual sources that influence the project timeline and schedule. Nonetheless, EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable. There are opportunities to compress schedules, expedite certain portions of the project schedule that are amenable to faster timetables, and conduct various components of the schedule concurrently.

Table 5. Illustrative Project Schedule for BSER Technologies, and Related Components[67]

[64] See the following examples of DOE-funded CCS project timelines: *https://www.netl.doe.gov/projects/project-information.aspx?k=FE0031581 ; https://netl.doe.gov/project-information?p=FE0031889; https://netl.doe.gov/sites/default/files/2022-05/IG-CarbonSAFE_20220512.pdf.*
[65] *Ibid.*
[66] DOE (2015). "A Review of the CO2 Pipeline Infrastructure in the U.S." DOE/NETL-2014/1681.
[67] Sargent & Lundy (2023). CCS Schedule (Coal Boilers or NGCC). Note: The schedule shown in this TSD includes an expedited schedule for certain portions of the project, as explained in the timing section. These expedited phases include the front-end feasibility and FEED work (to roughly 1 year) and the start-up, commissioning, and testing phase to 26 weeks.



4.7.2 Reasonableness of Costs

There are a variety of ways to assess and evaluate costs for CCS, and its reasonableness. The primary metric of interest is cost per ton of pollutant, but there are other metrics of importance. These include total capital cost of the project, fixed and variable operating cost of the pollution control, changes to the levelized cost of electricity and alternatives, amongst others. This section will explore these various costs for existing coal EGUs. Discussion of costs for natural gas combustion turbines can be found in the *GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines* TSD.

4.7.3 Cost and Performance of CCS Retrofit at Existing Coal EGUs

The cost of retrofitting an existing EGU with CCS technology involves significant capital expenditure. Capital cost estimates for deploying CCS retrofits to existing coal steam-fired generators come from a variety of sources. These include the Federal government, research institutions, and the private sector (utilities and engineering firms).

Table 6. EPA - Cost and Performance of CCS Retrofits to Coal EGUs for 90% Capture ($2019)[68]

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)[2]	Capacity Penalty (%)	Heat Rate Penalty (%)
400	**9,000**	1,915	27.9	4.3	27.6	38.1
	10,000	2,222	31.3	5.0	30.7	44.3
	11,000	2,557	35.0	5.8	33.7	50.9

[68] Source: EPA, CO_2 Reduction Retrofit Cost Development Methodology. Sargent & Lundy (2023). Available at Docket ID EPA-HQ-OAR-2023-0072. Incremental costs are applied to the derated (i.e., after retrofit) capacity. The CO_2 transportation, storage, and monitoring portion of the variable O&M is not included.

700	**9,000**	1,915	23.9	4.3	27.6	38.2
	10,000	2,222	27.2	5.0	30.7	44.3
	11,000	2,557	30.7	5.8	33.8	51.0
1,000	**9,000**	1,915	22.3	4.3	27.6	38.2
	10,000	2,222	25.5	5.0	30.7	44.3
	11,000	2,557	28.9	5.8	33.8	50.9

Table 7. DOE: Published Performance and Unit Cost Estimates for Carbon Capture Retrofits for 90% Capture (2018$)[69]

Capacity (MW)	HHV Heat Rate (Btu/kWh)	TOC Capital Cost (TOC, $/kW)	Fixed O&M ($/kW-yr) As-Reported Basis	Fixed O&M ($/kW-yr) Excluding PT&I	Variable O&M (mills/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)
495	**11,612**	1,825	130.5	50.2	14.7	23.8	31.2

4.7.4 Application of BSER ($/ton) at Existing Coal EGUs

Based on the EPA costs developed by Sargent & Lundy presented above, it is possible to calculate the costs expressed as $/ton abatement cost and $/MWh generation cost of CCS controls on a representative unit. The key assumptions for this analysis are as follows:

- Unit characteristics are based on recent coal fleet averages: 400 MW capacity; 10,000 Btu/kWh heat rate; 50 percent capacity factor
- Fuel costs are based on 2030 reference case projected average delivered costs: $1.47/MMBtu for coal
- CO_2 content of fuel: 205 lbs/MMBtu for coal
- Boiler modifications, based on EPA, Sargent & Lundy (2022): Capital cost $2,222/kW; 44 percent heat rate penalty; 31% capacity penalty; $5/MWh increase in VOM; $31/kW incremental FOM;

[69] Source: K. Buchheit, and N. Kuehn, "Eliminating the Derate of Carbon Capture Retrofits – Revision 2," National Energy Technology Laboratory, Pittsburgh, March 2023. Steady-state full load design capture rate for CO2 capture system. Design spec is for capture of CO_2 in flue gas for retrofitted unit. Represents the full load net capacity of the retrofitted facility. Costs are reported full total overnight costs of capture system and associated balance of plant divided by post retrofit net capacity. Total fixed O&M costs of retrofitted plant based on total annual estimated cost as reported in applicable citations. Total fixed O&M costs of retrofitted plant based on total annual estimated cost minus annual property taxes and insurance. This is similar to the Sargent & Lundy methodology as published in EIA NEMS assumption documentation. Variable operating costs are reported on the same basis as EPA methodology (e.g., CO_2 Transportation, Storage, and Monitoring portion of the variable O&M are excluded). The Integrated CCS configuration results in decreased net plant output due to capture system steam and electric demand (positive value for capacity penalty). *https://netl.doe.gov/projects/files/EliminatingtheDerateofCarbonCaptureRetrofitsRevision2_033123.pdf.*

- Assumes underground storage in saline aquifer, and 45Q consistent with amount of CO_2 stored.
- Transport and storage costs of $30/ton are included.

The detailed cost calculations for CCS can be found in the docket.[70] The table below presents the costs of a representative coal unit relative to both the estimated CO_2 emission reductions as well as the total generation. The table below reflects different potential capital amortization periods.[71]

Table 8. EPA Annual Cost Estimates, CCS (Representative Unit), 50% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	14	12
10	31	27
6	93	82
5	129	113
2	414	363

It is also possible to calculate the costs for the same representative unit, but assuming a different capacity factor. All else equal, higher capacity factors result in lower CCS costs (driven by higher levels of CO_2 storage and 45Q value) and lower capacity factors result in higher CCS costs (driven by lower levels of CO_2 storage 45Q value). The tables below illustrate the calculations assuming a 70% and 40% capacity factor.

[70] See Excel File: Coal CCS Cost Calculations.xls, in Docket ID No. EPA-HQ-OAR-2023-0072.
[71] These periods, along with the capital charge rate, convert the capital cost of an investment into a stream of levelized annual payments that ensures recovery of all costs associated with a capital investment including recovery of and return on invested capital and income taxes. For details on the components of the CCR, please see: *https://www.epa.gov/system/files/documents/2023-03/Chapter%2010%20-%20Financial%20Assumptions.pdf.*

Table 9. EPA Annual Cost Estimates, CCS (Representative Unit), 70% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	-8	-7
10	6	5
6	58	51
5	87	76
2	324	284

Table 10. EPA Annual Cost Estimates, CCS (Representative Unit), 40% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	33	29
10	53	46
6	124	109
5	165	145
2	492	432

Based on the EPA costs developed by Sargent & Lundy presented above, and nearest saline storage reservoir, it is also possible to calculate the average costs expressed as $/ton abatement cost and $/MWh generation cost of CCS controls for the universe of units that do not have announced plans to cease operation by 2030. The tables below calculate average costs for this universe of units under different amortization periods and different assumed capacity factor levels.

Table 11. EPA Annual Cost Estimates, CCS (Unit-specific data), 50% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	8	7
10	24	22
6	82	76
5	115	107
2	379	355

Table 12. EPA Annual Cost Estimates, CCS (Unit-specific data), 70% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	-16	-14
10	-3	-2
6	43	41
5	70	65
2	281	263

Table 13. EPA Annual Cost Estimates, CCS (Unit-specific data), 40% capacity factor ($2019)

Capital Amortization Period (years)	Estimated Costs ($ per short ton CO_2 reduced)	Estimated Costs ($ per MWh of generation)
12	28	27
10	47	44
6	115	108
5	154	144
2	465	435

The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects. A list of CCS projects tracked by the Global CCS Institute is available as an attachment to this TSD.[72] The cost of CO_2 capture from low-to-medium partial pressure sources such as coal-fired power generation has been trending downward over the past decade, and is projected to fall by 50% by 2025 compared to 2010.[73] This is driven by the familiar learning-processes that accompany the development and deployment of any industrial technology. Studies of the cost of capture and compression of CO_2 from power stations completed ten years ago averaged around $95/tonne ($2020). Comparable studies completed in 2018/2019 estimated capture and compression costs could fall to approximately 50/tonne CO_2 by 2025. Note, these estimates do not include the impact of the 45Q tax credit as enhanced by the IRA.

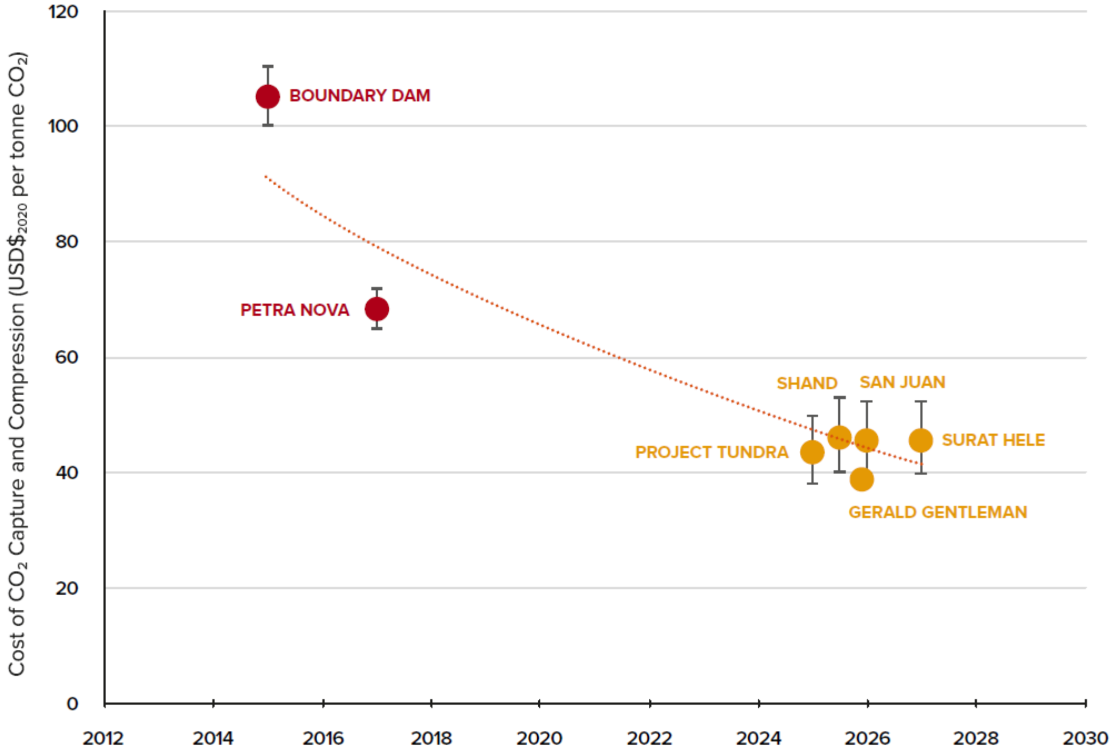
Current target pricing for announced projects at coal plants is approximately $40/tonne on average, compared to Petra Nova and Boundary Dam, whose actual costs were reported to be $65 and $105/tonne, respectively.[74]

[72] Global CCS Institute 2022 Status Report Facilities List. https://status22.globalccsinstitute.com/2022-status-report/appendices/

[73] Technology Readiness and Costs of CCS (2021). Global CCS Institute. Available at *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf.*

[74] *Ibid.*

Figure 3. Cost of CO_2 capture and compression at commercial post-combustion CO_2 capture facilities at coal-fired power plants, including the ones in operation (red) and in advanced development (orange shown for Front End Engineering Design, FEED)[75] – Global CCS Institute (2021)



4.7.4.1 *CO_2 Transportation and Storage Costs*

There are various sources of CO_2 transportation and storage costs. One of the more comprehensive sources for these costs is from National Energy Technology Laboratory (NETL). NETL provides estimates of CO_2 transport and storage costs in "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies" ("Quality Guidelines") report.[76] For transportation costs, NETL cites its CO_2 Transport Cost Model, which estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operation and management (O&M) costs. NETL also estimates costs associated with the storage of CO_2 in the Quality Guidelines report. These estimates reflect the cost of site screening and evaluation, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Sequestration costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations.

There are two primary cost drivers for a CO_2 sequestration project: injection of CO_2 and the areal extent of the CO_2 plume in the reservoir. The rate of injection of CO_2 into the reservoir depends, in part,

[75] Graphic is from 2021, since that time the San Juan project has been tabled.
[76] Grant, T. et al. "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. Available online at: *https://www.netl.doe.gov/energy-analysis/details?id=3743*.

on the reservoir permeability and the thickness of the reservoir. Thick, permeable reservoirs provide for better injection and fewer injection wells. The sequestration capacity of the reservoir influences the areal extent of the CO_2 plume. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have lower testing and monitoring costs.

NETL modeled a base-case transportation and storage cost scenario that assumed the following project timeline: Site screening - one year; site selection and site characterization – three years; permitting and construction - two years; operations – 30 years; and post-injection site care and site closure – 50 years. These timelines are likely conservative in that site screening, selection, characterization, and permitting and construction on average takes about four to four and a half years, which is consistent with EPA's evaluation of project timelines presented in this memo. Costs were modeled for a given cumulative storage potential. At a storage potential of 25 gigatons, costs range (in 2018$/metric ton of CO_2 sequestered) between $8.32/metric ton ($7.55/short ton) (in the Illinois Basin) to $19.84/metric ton ($18.00/short ton) (in the Powder River Basin).[77] These cost estimates are a representative price range for a subset of saline storage potentials, and do not cover costs for all states previously identified as having storage potential.

4.7.5 CO_2 Emission Reductions

CCS projects in power and industrial plants operating today are designed to capture around 90% of the CO_2 from flue gas. The 90% capture rate has been demonstrated at many facilities, including at Boundary Dam Unit 3 and Petra Nova. There are no technical barriers to increasing capture rates beyond 90% for the most mature capture technologies (amine-based systems), although there is limited experience with capture rates higher than 90% on EGUs.

One of the goals of the Petra Nova project was to demonstrate successful operation of an advanced amine post-combustion process to achieve 90% CO_2 capture efficiency. In a DOE assessment of the project, Petra Nova successfully constructed a 240 MWe commercial-scale project using the KM-CDR Process®. When operating at 100%, the carbon capture facility captured the targeted 5,200 tons of CO_2 per day. Through the 3-year Demonstration Period, the capture system captured 92.4% of the CO_2 from the slip stream of flue gas processed.[78]

4.7.6 Non-CO_2 Emissions

For amine-based CO_2 capture retrofits to coal-fired steam generating units, decreased efficiency and increased utilization would otherwise result in increases of non-GHG emissions; however, importantly, most of those impacts would be mitigated by the flue gas conditioning required by the CO_2 capture process and by other control equipment that the units already have or may need to install to meet other CAA requirements. Decreases in efficiency result in increases in the relative amount of coal combusted per amount of electricity generated and would otherwise result in increases in the amount of non-GHG pollutants emitted per amount of electricity generated. Additionally, increased utilization would otherwise result in increases in total non-GHG emissions. However, substantial flue gas conditioning, particularly to remove SO_2, is critical to limiting solvent degradation and maintaining reliable operation of the capture plant. To achieve the necessary limits on SO_2 levels in the flue gas for the capture process, steam generating units will need to add an FGD column, if they do not already have one, and may need an additional polishing column (i.e., quencher). A wet FGD column and a polishing

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[77] Grant, T. et al. "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. Available online at: *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[78] DOE/NETL Final Technical Report: W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project. Available at https://www.osti.gov/servlets/purl/1608572.
Final Scientific/Technical Report.

column will also reduce the emission rate of particulate matter. Additional improvements in particulate matter removal may also be necessary to reduce the fouling of other components (e.g., heat exchangers) of the capture process (e.g., heat exchangers or bag houses). NOx emissions can cause solvent degradation and nitrosamine formation by chemical absorption of NOx, depending on the chemical structure of the solvent. A conventional multistage water or acid wash and mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (e.g., nitrosamine) emissions. NOx levels of the flue gas required to avoid solvent degradation and nitrosamine formation in the CO_2 scrubber vary. For most units, the requisite limits on NOx levels to assure that the CO_2 capture process functions properly may be met by the existing NOx combustion controls, and those units may not need to install SCR for process purposes. However, most existing coal-fired steam generating units either already have SCR or will be covered by proposed Federal Implementation Plan (FIP) requirements regulating interstate transport of NOx (as an ozone precursors) from EGUs. See 87 FR 20036 (April 6, 2022).

Pollutant	**Post Combustion Capture Emission Impacts**
SO_2	No change expected for enzyme technologies. For cryogenic systems, pilot tests show over 90% SO_2 removed.[79] Generally, SO_2 will be controlled to 1-5 ppmv-dry for all other technologies.
VOCs	Increase for amine technologies, will vary depending on flue gas conditions.[80] Mitigation methods can be included to help minimize increase.[81] VOC reduction for cryogenic, depending upon specific VOC and relative vapor pressure/critical temperature to CO_2. Generally, no significant change expected for other technologies, although some may reduce the VOC emissions, depending upon the solubility of the specific VOC in question.
NH_3	Potential increase for chilled ammonia technology due to carryover. Mitigation methods are included in design to minimize increase. Likely significant reduction depending on upstream equipment for all other technologies, due to solubility of NH3. With an upstream WFGD, the incremental NH3 reduction may be smaller. (not expected to be lower than units with WFGD).[82] Because NH3 has a much higher critical temperature than CO_2, high NH_3 reduction in a cryogenic CCS system is likely.

[79] *https://www.netl.doe.gov/sites/default/files/2017-12/L-Baxter-SES-Cryogenic-Carbon-Capture.pdf https://webbook.nist.gov/cgi/cbook.cgi?ID=C124389&Mask=4&Type=ANTOINE&Plot=on#ANTOINE.*
[80] VOC emissions from amine solvents are primarily due to solvent carryover, the quantity and makeup of the VOC emissions will vary depending on the flue gas constituents and solvent formulation. Some solvents have been demonstrated to be less susceptible to certain flue gas constituents and may result in lower VOC emission increases. However, all amine technology vendors have indicated that there will be an increase in VOC emissions.
[81] VOC mitigation methods may be included as part of the CO_2 capture system and may include Brownian diffusion units, wet electrostatic precipitators, acid washes, and other process changes. The type of mitigation technology will depend on the flue gas constituents, solvent formulation, and potential permitting implications.
[82] A reduction in ammonia may occur within the CO_2 capture pre-treatment equipment due to the high volume of circulating water, mechanism for this reduction is the same as when ammonia is captured in a wet FGD. Reduction is only likely to be realized if there is a significant quantity of ammonia in the flue gas (due to SNCR / SCR) and if the unit is not already equipped with wet FGD.

Pollutant	Post Combustion Capture Emission Impacts
$PM_{2.5}$	Potential reduction depending on upstream equipment for all technologies (not expected to be lower than units with WFGD).[83] Pilot tests show high $PM_{2.5}$ removal from cryogenic.[84] Additionally, a high condensable PM removal rate is likely.
PM_{10}	Potential reduction depending on upstream equipment for all technologies (not expected to be lower than units with WFGD).[4] Pilot tests show high PM 10 removal from cryogenic[85]
NOx	No or negligible change expected for all technologies, except cryogenic. Pilot tests showed high NO removal for cryogenic.[86]
CO	No change expected for all technologies.

Installation of CCS systems will require that pollutants and contaminants are removed from the stack emissions. This requires that SO_2, NOx, PM, Hg, and HCl are actively controlled with some scrubbing system (i.e., wet flue gas desulfurization (FGD)), have NOx control (i.e., LNBs with overfire air (OFA) and selective catalytic reduction (SCR)), and controls to manage particulates and heavy metals (baghouse, dry sorbent injection (DSI), and/or activated carbon injection (ACI)).

4.8 Evaluation of Geographic Availability of Geologic Sequestration for New Combustion Turbines

Geologic storage is widely available, and a significant number of CO_2 pipelines exist or are under construction in the United States. As new combustion turbines are sited and constructed, the location of those turbines in relation to geologic sequestration sites and pipelines could be considered. There are other factors that influence the location of new turbines, such as proximity to electricity demand. In situations where new turbines cannot be located near geologic sequestration sites or existing pipeline infrastructure, multiple solutions may be used.

New CO_2 pipelines can be built or, as discussed in Section 4.6, smaller quantities of CO_2 can be transported via ship, road tanker, or rail tank cars in tandem with pipelines to move large volumes of CO_2. Electricity demand in states that may not have geologic sequestration sites available could be served by generation built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines. This method has been used previously in the electricity sector when siting a coal-fired power plant near a coal mine, and transmitting the generated electricity long distances to the load area. EPA discussed this use of "coal-by-wire" in "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule," 80 FR 64510, 64582-83 (October 23, 2015) (2015 NSPS). This approach is generally less expensive than siting the plant near the load area and shipping the coal long distances. As EPA explained in the 2015 NSPS, coal-by-wire could be used to deliver electricity generated by coal-fired power plants to states that may not have geologic sequestration sites. A similar strategy could be employed in which

[83] A reduction in $PM_{2.5}$ and PM_{10} may occur within the CO_2 capture pre-treatment equipment due to the high volume of circulating water, and in some cases addition of caustic solution, the mechanism for this reduction is the same as when $PM_{2.5}$ and PM_{10} is captured in a wet FGD. Reduction is only likely to be realized if the unit is not already equipped with wet FGD. In cases where VOC mitigation is implemented, reduction in $PM_{2.5}$ and PM_{10} may also be realized, however this has not yet been demonstrated or guaranteed by the technology vendors.
[84] *https://www.netl.doe.gov/sites/default/files/2017-12/L-Baxter-SES-Cryogenic-Carbon-Capture.pdf.*
[85] *Ibid.*
[86] *Ibid.*

newly built combustion turbines could serve load in states that may not have geologic sequestration sites. There are many examples of combustion turbines that serve load in a state other than the one in which they are located. One example is the Intermountain Power Agency project in Utah will replace an existing coal-fired EGU with an 840 MW combustion turbine designed to serve load in Los Angeles, California.[87] A second is the AMP Fremont Energy Center (AFEC), a 700-MW NGCC facility in Fremont, Ohio. AFEC reached full commercial operation in January 2012. American Municipal Power (AMP) owns 90.69 percent of AFEC on behalf of 87 participating AMP members in seven states and 4.15 percent on behalf of the Central Virginia Electric Cooperative. The Michigan Public Power Agency owns the remaining 5.16 percent. The facility supplies power to 86 AMP member communities as well as DEMEC and CVEC.[88] Most broadly, as the Energy Information Administration has stated:[89]

> Electricity routinely flows among the Lower 48 states and, to a lesser extent, between the United States and Canada and Mexico…. States with major population centers and relatively less generating capacity within their state boundaries tend to have higher ratios of net electricity imports to total electricity consumption…. Many states within the continental United States fall within integrated market regions, referred to as independent system operators or regional transmission organizations. These integrated market regions allow electricity to flow freely between states or parts of states within their boundaries.

Therefore, electricity generating plants are routinely constructed to serve demand in states in addition to where they are located. A recent example includes the Lordstown Energy Center, a NGCC facility in Lordstown, Ohio, which "provides safe, clean, efficient and reliable power supply to approximately 850,000 homes and businesses served by PJM Interconnection's regional transmission network."[90] The PJM Interconnection coordinates the movement of electricity through 13 states and the District of Columbia.[91] A second recent example includes the Cricket Valley Energy Center, a NGCC facility in Dover, NY, which provides electricity to serve approximately 1 million homes in ISO New England, which, in turn, coordinates the movement of electricity through 6 states.[92]

[87] Mitsubishi Power (2020) "Intermountain Power Agency Orders MHPS JAC Gas Turbine Technology for Renewable-Hydrogen Energy Hub," https://power.mhi.com/regions/amer/news/200310.html.
[88] https://www.amppartners.org/generation/fossil-fuels.
[89] https://www.eia.gov/todayinenergy/detail.php?id=38912
[90] https://lordstownec.com/about-us/
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