

- TECHNICAL SUPPORT DOCUMENT -

To: Docket EPA-HQ-OAR-2013-0495
Date: July 10, 2015
Subject: Literature Survey of Carbon Capture Technology

Introduction

On January 8, 2014, the Environmental Protection Agency (EPA) proposed New Source Performance Standards (NSPS) to limit carbon dioxide (CO₂) emissions from new fossil fuel-fired electricity generating units (EGUs) under Clean Air Act (CAA) §111(b).¹ Carbon capture and storage (CCS), also known as "carbon capture and sequestration," was evaluated as an option for new steam generating boilers and integrated gasification combined cycle (IGCC) units in developing the proposed and final NSPS. In determining the best system of emission reduction adequately demonstrated (BSER) to establish the standards, the EPA reviewed literature covering existing projects that implement CCS, existing projects that implement various components of CCS, planned CCS projects, and scientific and engineering studies of CCS. The final NSPS contains an emission limit of 1,400 pounds CO₂ per megawatt hour on a gross basis (lb CO₂/MWh-g) for new steam generating boilers and IGCC units based on partial CCS (i.e., CCS on a portion or "slip-stream" of the EGU exhaust). Among other compliance approaches,² partial CCS was determined to be adequately demonstrated based on the fact that post-combustion CCS is demonstrated in full-scale operation within the electricity generating industry, and full-scale pre-combustion CCS has been demonstrated in several chemical industry plants with results that are reasonably transferable to the electricity generating sector. It is important to note that the NSPS does not require near-term widespread use of full CCS for all electric utilities, but rather is based on partial CCS for only the subset of *new* fossil-fuel fired electric utility boilers or IGCC units.

The purpose of this technical support document (TSD) is to provide an overview of CCS technology and describes the status of sources implementing CCS projects to date. This TSD provides information on the technological feasibility of CCS (including partial CCS), but does not discuss costs. The EPA's conclusions regarding the costs and emission reductions associated with implementation of partial CCS are based on in-depth studies of costs by DOE/NETL reports and recent EIA AEO projections and are documented in a separate memorandum and the Regulatory Impact Analysis for the final NSPS. Similarly, a separate document discusses funding mechanisms associated with CCS projects.

This document is organized as follows:

¹ Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430.

² It is noted that a new utility boiler or IGCC unit can meet the final standard of performance of 1,400 lb CO₂/MWh by co-firing natural gas should project developers choose to delay implementation of partial CCS.

I. Overview of CCS Technology for Fossil-fuel Fired EGUs

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I. Overview of CCS Technology for Fossil-fuel Fired EGUs

Use of fossil fuel to generate electricity commonly occurs in one of the following systems:

- A steam generating unit (also referred to simply as a “boiler”) that feeds a steam turbine that spins an electric generator.
- A combustion turbine (or reciprocating internal combustion engine) that directly drives the generator. Some modern power plants use a “combined cycle” electric power generation process, in which a gaseous or liquid fuel is burned in a combustion turbine that both drives electrical generators and provides heat to produce steam in a heat recovery steam generator (HRSG) that drives a second electric generator to increase the overall efficiency of the electric power generation process.
- An integrated gasification combined cycle (IGCC) system that first gasifies solid fuel and burns the resulting syngas in a combined cycle stationary combustion turbine for electric generation.

The majority of new fossil-fuel fired electric generating units are projected to use natural-gas combined cycle technology which results in lower CO₂ emissions per MWh of electricity produced than steam generating units or IGCC systems burning solid fossil fuels such as coal. Use of CCS was analyzed as an option for reducing CO₂ emissions from new steam generating units and new IGCC systems for purposes of the NSPS.

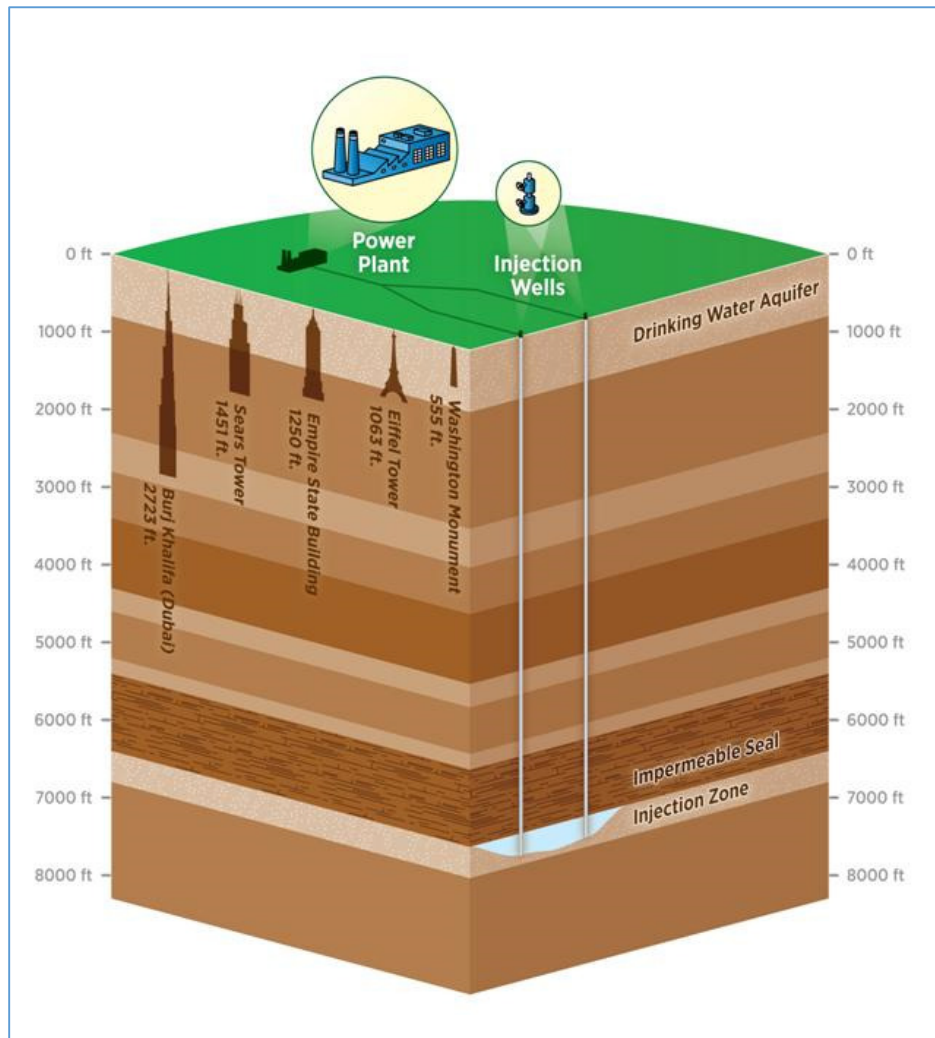
Carbon capture and storage (CCS) involves the separation and capture of CO₂ from flue gas, or syngas in the case of IGCC. CCS is a three-step process that includes:

1. Capture of CO₂ from electric generating units (or other industrial processes);
2. Compression and transport of the captured CO₂ (usually in pipelines);
3. Underground injection and geologic sequestration (also referred to as storage) of the CO₂ into deep underground rock formations. These formations are often a mile or

more beneath the surface and consist of porous rock that holds the CO₂. Overlying these formations are impermeable, non-porous layers of rock that trap the CO₂ and prevent it from migrating upward.

Figure 1 illustrates the typical depth at which CO₂ would be injected.

Figure 1. CCS Schematic
(Subsurface depth to scale, 5,280 feet equals one mile) (EPA, 2013c)



Geologic sequestration is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO₂ increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). CO₂ may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.³

³ Other types of opportunities include organic shales and basalt.

A study prepared for the U.S. DOE by the Pacific Northwest National Laboratory (Dooley, 2009) evaluated the development status of various CCS technologies. The study addressed the availability of capture processes; transportation options (CO₂ pipelines); injection technologies; and measurement, verification, and monitoring technologies. The study concluded that, in general, CCS was technically viable at the time of the report (2009) although full-scale CCS systems had not yet been installed and fully integrated at an EGU at that time. The study also did not address the cost or energy requirements of implementing CCS technology.⁴

In 2010, an Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of CCS technologies (Interagency Task Force, 2010). The Task Force was specifically charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing commercial demonstration projects online by 2016. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical barriers to implementation.⁵

Much research and development has occurred in the 5 years since these DOE and interagency reports were written in the 2009-2010 timeframe. As described in more detail in Section II of this report, full-scale EGU CCS demonstration projects are underway. Research to reduce the energy requirements of CCS technologies and improve its cost-effectiveness continues, as described in section I.F of this document. A more recent report from the DOE/NETL provides a technology update and summarizes research continuing research sponsored by the DOE (NETL, 2013). The EPA's updated cost analysis for CCS systems based on DOE/NETL analyses (from 2010-2015), EIA AEO projections (from 2014), and other recent information is presented in the RIA for the NSPS.

The following subsections provide an overview of CO₂ capture technology, CO₂ compression, CO₂ pipeline infrastructure for transportation, geologic sequestration, and alternatives to geologic sequestration.

A. CO₂ Capture Technology

In general, CO₂ capture technologies applicable to fossil-fuel fired power generation can be categorized into three approaches:

- **Post-combustion systems** are designed to separate CO₂ from the flue gas produced by fossil-fuel combustion in air.

⁴ For up-to-date information on Department of Energy's National Energy Technology Laboratory's (NETL) Carbon Sequestration Program go to the NETL web site (NETL, 2015b) at: <http://www.netl.doe.gov/research/coal/carbon-storage/research-and-development>.

⁵ For additional information on the Interagency Task Force and its findings on CCS, go to: <http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf>

- **Pre-combustion systems** are designed to separate CO₂ and H₂ in the high-pressure syngas produced at IGCC power plants.
- **Oxy-combustion** uses high-purity oxygen (O₂), rather than air, to combust coal and therefore produces a highly concentrated CO₂ stream.

The post- and pre-combustion CO₂-capture processes typically use solvents, solid sorbents, and membrane-based technologies for separating and capturing CO₂. Solvents chemically absorb the CO₂ which is separated from the solvent in a regeneration step. Solid sorbents capture CO₂ through chemical adsorption, physical adsorption, or a combination of the two effects. Membrane-based capture uses permeable or semi-permeable materials to produce a highly concentrated CO₂ stream that does not require a separation/capture step.

Each of the CO₂-capture approaches results in increased capital and operating costs and decreased electricity output (or energy penalty⁶), thereby increasing the cost of electricity.⁷ The energy penalty occurs because the CO₂ capture process uses some of the energy produced from the plant (Interagency Task Force, 2010). Research is underway to reduce CO₂ capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO₂ from fossil-fuel energy plants compared to currently available capture technologies. The large-scale CO₂ capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will continue to generate operational knowledge and enable continued commercialization and deployment of these technologies. The EPA is currently finalizing an NSPS limit based on partial CCS (as opposed to CCS of the full exhaust stream) to help mitigate the energy penalty and costs of CCS as the technology continues to emerge and be refined through further research.

Each of the CO₂-capture systems are described and discussed in more detail in the subsections below. Facility-specific applications of CO₂ capture systems are discussed in Section II.

1. Post-combustion CO₂ capture

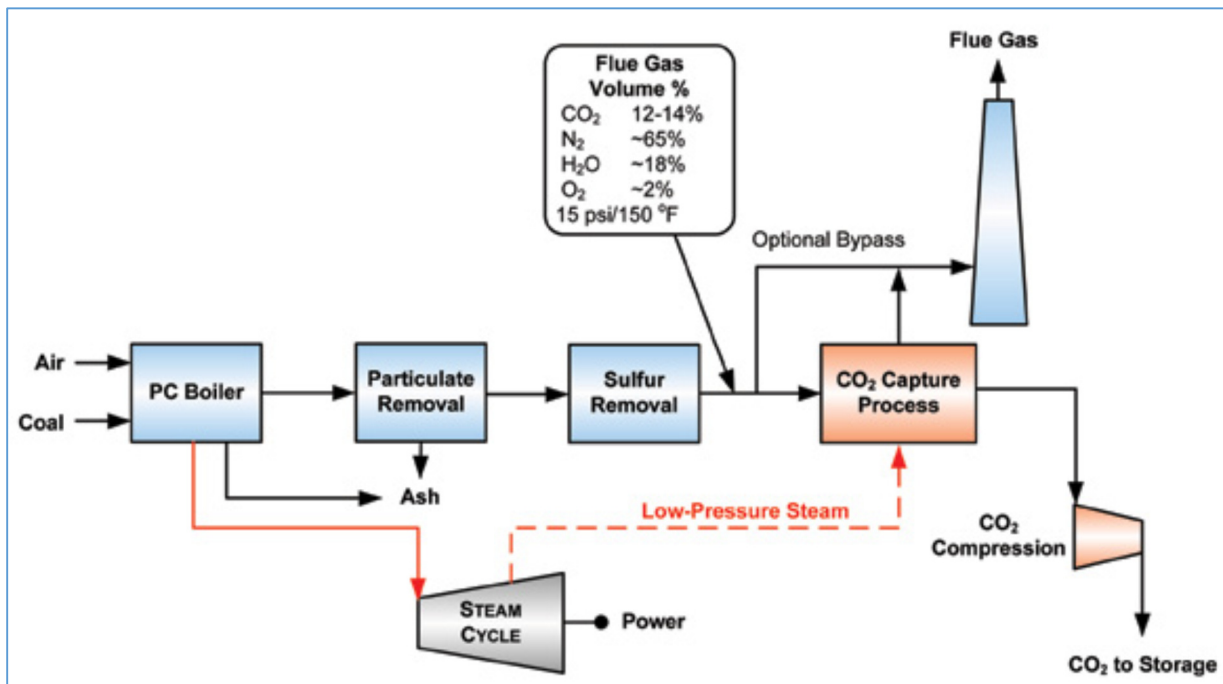
Post-combustion CO₂ capture refers to removal of CO₂ from combustion flue gas prior to discharge to the atmosphere. It is referred to as “post-combustion capture” because the CO₂ is the

⁶ The energy penalty represents the percentage reduction in the power plant operating efficiency. For example, a reduction in efficiency from 30 percent to 20 percent represents a 10 percentage point drop in efficiency, which is equivalent to a 33 percent energy penalty.

⁷ There is on-going research sponsored by DOE/NETL and others to further reduce the energy requirements of the carbon capture systems. Progress is being made. For example, the heat duty (the energy required to regenerate the capture solvent) for the amine scrubbing process used at the Searles Valley facility in the mid-70's was about 12 MJ/mt CO₂ removed as compared to a heat duty of about 2.5 MJ/mt CO₂ removed for the amine processes used in 2014 at Boundary Dam and for the amine system that will be used at the WA Parish facility.

product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. A simplified process schematic of post-combustion CO₂ capture is shown in **Figure 2** (NETL, 2013).

Figure 2: Diagram Illustrating a Pulverized Coal Boiler with Post-Combustion CO₂ Capture



As noted previously, in a typical fossil fuel-fired steam generating unit, fuel is burned with air in a boiler to produce steam that drives a turbine/generator to produce electricity. Flue gas from the boiler consists primarily of N₂ and CO₂ with other components in trace amounts (e.g., particulate matter (PM), sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrochloric acid (HCl) etc.) The CO₂ capture process is located downstream of the conventional pollutant controls for removal of PM and acid gases so these components will not interfere with CO₂ removal. In addition to the need to remove pollutants upstream of the CO₂ capture system, challenges to separating CO₂ from steam generating unit combustion flue gas include:

- the high volume of gas to be treated because the CO₂ is dilute (13–15 volume percent in coal-fired systems);
- the low pressure [15–25 pounds per square inch (psi)] of the flue gas;
- and the large auxiliary power load to compress captured CO₂ from near atmospheric pressure to pipeline pressure (about 2,200 psi).

The volume of flue gas to be treated (and the associated energy penalty) is reduced in partial CO₂ capture systems, where a slipstream of the flue gas is treated as opposed to the entire flue gas stream.

The CO₂ capture process involves use of a chemical solvent, solid sorbent, or membrane to separate CO₂ from the flue gas. Amine-based solvent systems are most commonly used for post-combustion capture systems. When contacted with the combustion flue gas, then solvent participates in a chemical absorption (chemisorption) separation process in which the CO₂ is absorbed by the liquid solvent. Solid sorbents can be used to capture CO₂ from flue gas through

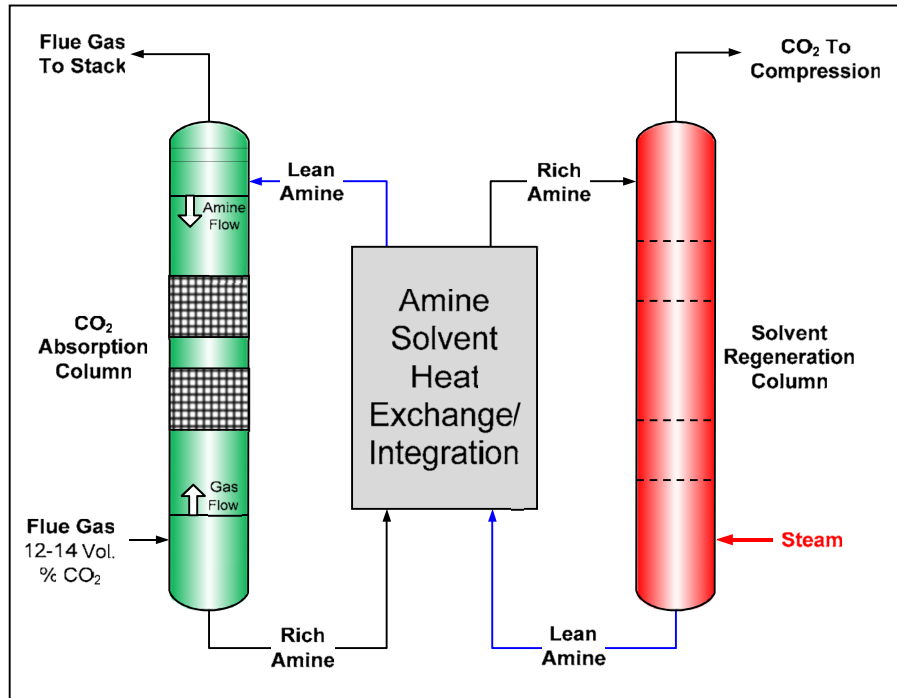
chemical adsorption, physical adsorption, or a combination of the two. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO₂ from flue gas (NETL, 2015c).

Gas absorption processes using chemical solvents, such as amines, to separate CO₂ from other gases have been in use since the 1930s in the natural gas industry to produce food and chemical grade CO₂. Amine-based solvent systems are in commercial use for scrubbing CO₂ from industrial flue gases and process gases, and are available for use in CCS systems at electric utilities. Following absorption into the amine-based solvent, a high purity CO₂ stream is separated from the solvent in a steam stripping (solvent regeneration) process, where the solvent is heated with low pressure steam from the power plant's steam cycle. Solvent regeneration is responsible for much of the "energy penalty" of the CO₂ capture system because steam that could otherwise be used to generate electricity is instead used in the solvent regeneration process. Development of advanced solvents – those that are chemically stable, have high CO₂ absorption capacities, and have low regeneration energy requirements – continues to be an active area of research. The DOE/NETL's post-combustion CO₂ control technology R&D program includes projects directed at the use of solvents, solid sorbents, and membranes.

Amines chemically react with CO₂ via reversible reactions to form water-soluble compounds. Despite the low CO₂ partial pressure in combustion flue gas, amines are capable of achieving high levels of CO₂ capture due to fast kinetics and strong chemical reactions. However, the absorption capacity for commercially available amines is chemically limited, requiring two molecules of amine for each molecule of CO₂. In addition, usable amine solution concentrations are typically limited by viscosity and corrosion. Therefore, current amine systems are only between 20 and 30 percent amine with the remaining being water. Although the water present in the solution helps control the solvent temperature during absorption, which is an exothermic reaction, the water also requires significant amounts of sensible heating and stripping energy upon CO₂ regeneration. Not every amine system is the same, and various vendors offer different designs. In general, depending on the amount of heat integration, anywhere from 1,550 to greater than 3,000 British thermal units (Btu) per pound of CO₂ in the form of low pressure steam (approximately 45 psi) is required to regenerate the solvent to produce a concentrated CO₂ stream at a pressure of approximately 25 psi (Interagency Task Force, 2010).

An amine-based post-combustion capture process is depicted in **Figure 3**.

Figure 3. Schematic Diagram of Amine-based CO₂ Capture Process



After conventional air pollutant (SO_x, NO_x, PM) cleanup, the combustion flue gas enters an absorber reactor and flows counter-currently to a CO₂-lean solvent where CO₂ is absorbed into, and chemically reacts with the amine solution. The treated flue gas (mostly N₂) is discharged to the atmosphere, and the CO₂-rich amine solution is pumped to a solvent regeneration column where the CO₂-rich solution is heated in order to reverse the chemical reactions between the CO₂ and amine solvent. Steam extracted from the turbine cycle provides the heat for regeneration of the amine solvent in the solvent regeneration column. Consequently, CO₂ is released, producing a concentrated stream that exits the regeneration column and is then cooled and dehumidified in preparation for compression, transport, and storage. From the solvent regeneration column, the CO₂-lean solution is cooled and returned to the absorber for reuse (Interagency Task Force, 2010).

Post-combustion CO₂ capture offers the greatest near-term potential for reducing power sector CO₂ emissions because it can be tuned for various levels of CO₂ capture (e.g., in partial capture systems as indicated by the optional bypass in **Figure 2**). Post-combustion capture technologies are available for application to conventional coal-fired power plants and the combustion flue gas from IGCC power plants (Interagency Task Force, 2010; NETL, 2013). Many projects are in the planning stages for demonstration scale-up including the Alstom chilled ammonia process and several amine-based processes (e.g., Fluor [Econamine], ABB/Lummus, Mitsubishi Heavy Industries [MHI], HTC Purenergy, Aker Clean Carbon, Cansolv, et al.) (Interagency Task Force, 2010).

The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO₂ capture. Most single component amine systems are

not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process uses a monoethanolamine (MEA) formulation specially designed to recover CO₂ and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS-1 solvent) which are less susceptible to degradation and corrosion issues. Several companies offering post-combustion CO₂ capture technologies have offered performance guarantees or made public statements regarding the technical feasibility of their systems for CO₂ capture from fossil-fuel fired power plants. For example:

- Linde and BASF offer performance guarantees for CCS technology. The two companies are jointly marketing new, advanced technology for capturing CO₂ from low pressure gas streams in power or chemical plants. In product literature (BASF/Linde, undated) they note that Linde will provide a turn-key carbon capture plant using a scrubbing process and solvents developed by BASF, the world's leading technical supplier for gas treatment. They further note that:
 - The captured carbon dioxide can be used commercially for example for EOR (enhanced oil recovery) or for the production of urea. Alternatively it can be stored underground as a carbon abatement measure. [...] The PCC (Post-Combustion Capture) technology is now commercially available for lignite and hard coal fired power plant [...] applications.
 - The alliance between Linde, a world-leading gases and engineering company and BASF, the chemical company, offers great benefits [...] Complete capture plants including CO₂ compression and drying ... Proven and tested processes including guarantee ... Synergies between process, engineering, construction and operation ... Optimized total and operational costs for the owner.

- Fluor has developed patented CO₂ recovery technologies to help its clients reduce GHG emissions. The Fluor product literature (Fluor, 2015) specifically points to Econamine FG PlusSM process which uses an amine solvent to capture and produce food grade CO₂ from post-combustion sources. The literature further notes that Econamine FG PlusSM (EFG+) is also used for carbon capture and sequestration projects, that the proprietary technology provides a proven, cost-effective process for the removal of CO₂ from power plant flue gas streams and that the process can be customized to meet a power plant's unique site requirements, flue gas conditions, and operating parameters.

- Fluor has also published an article titled "Commercially Available CO₂ Capture Technology" in which it describes the EFG+ technology (Johnson et. al, 2009). The article notes, "Technology for the removal of carbon dioxide (CO₂) from flue gas streams has been around for quite some time. The technology was developed not to address the GHG effect but to provide an economic source of CO₂ for use in enhanced oil recovery and industrial purposes, such as in the beverage industry."

- Mitsubishi Heavy Industries (MHI) offers a CO₂ capture system that uses a proprietary energy-efficient CO₂ absorbent called KS-1TM. Compared with the

conventional monoethanolamine (MEA)-based absorbent, KS-1™ solvent requires less solvent circulation to capture the CO₂ and less energy to recover the captured CO₂.

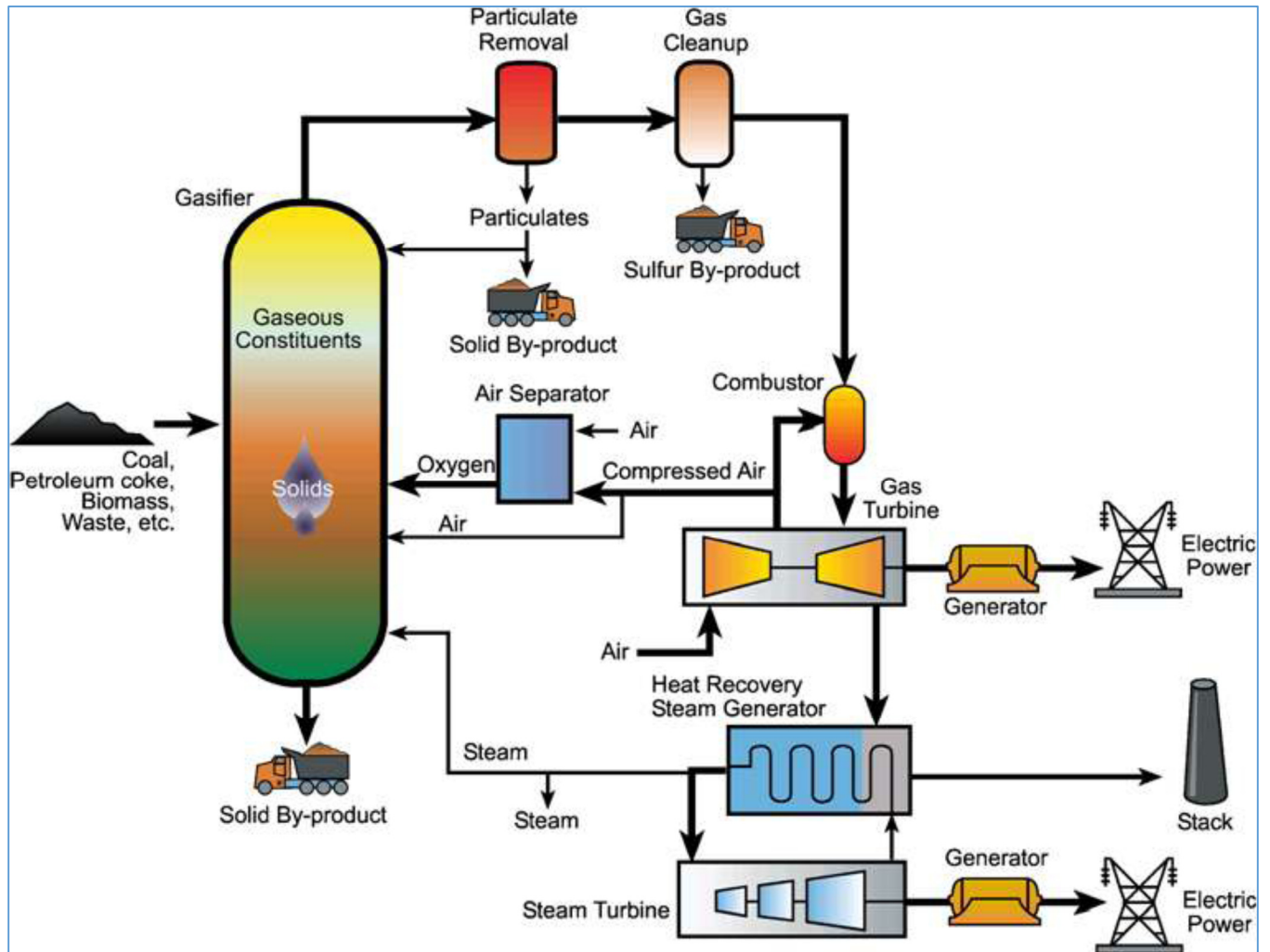
- Shell has developed the CANSOLV CO₂ Capture System, which Shell describes in its product literature as a world leading amine based CO₂ capture technology that is ideal for use in fossil fuel-fired power plants where enormous amounts of CO₂ are generated. The company also notes that the technology can help refiners, utilities and other industries lower their carbon intensity and meet stringent GHG abatement regulations by removing CO₂ from their exhaust streams, with the added benefit of simultaneously lowering SO₂ and NO₂ emissions.

The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO₂ capture performance and reduce costs.

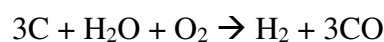
2. Pre-combustion CO₂ capture

Pre-combustion CO₂ capture, as its name implies, takes place before the process gas is combusted to generate steam at a power plant. Pre-combustion capture is applicable mainly to IGCC processes where fuel is converted into gaseous components by applying heat under pressure in the presence of steam and limited O₂, as shown in **Figure 4**.

Figure 4. Schematic of an integrated gasification combined cycle (IGCC) power plant. (EPA, 2010)



In an IGCC system, the fuel (usually coal or petroleum coke at electric utilities) is heated with water and oxygen in an oxygen-lean environment. Unlike a boiler, a gasifier carefully controls the amount of air or oxygen available inside it so only a small portion of the fuel burns completely. This "partial oxidation" process provides heat to drive gasification reactions. Rather than burning, most of the fuel is chemically broken apart by the heat and pressure in the gasifier, setting into motion chemical reactions that produce syngas. The fuel (carbon), water and oxygen react to form primarily a mixture of hydrogen (H₂) and carbon monoxide (CO) known as synthesis gas or "syngas" according to the following high temperature reaction:

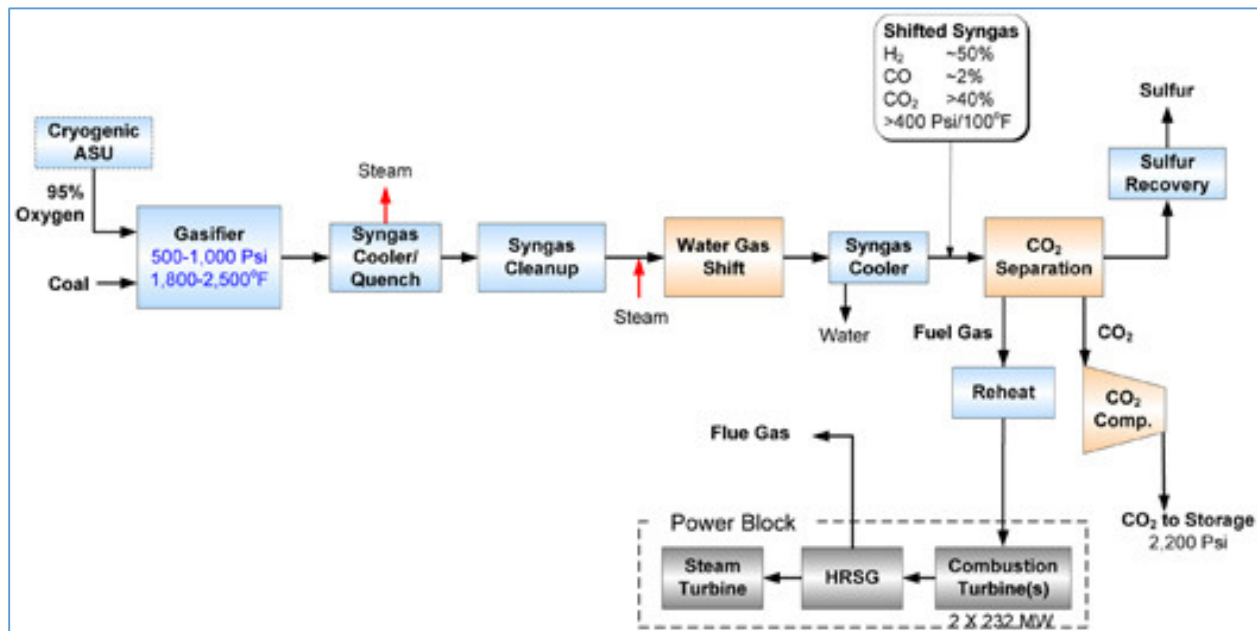


Although syngas is predominantly H₂ and CO, it can include other gaseous constituents (e.g., hydrogen sulfide (H₂S), carbonyl sulfide (COS), and CO₂) in varying compositions depending on

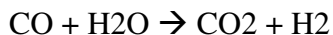
fuel characteristics and the conditions in the gasifier. The amount of CO₂ in syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less than 20 volume percent. The gasification process also produces inorganic materials originating from the coal (e.g., minerals, ash). After removal of the impurities, the syngas is combusted using a conventional combustion turbine in a combined cycle configuration (i.e., a combustion turbine combined with a heat recovery steam generator and steam turbine). Most syngas streams are at higher pressure and can contain higher concentrations of CO₂ than conventional steam generating units (especially if the syngas is shifted to enrich the CO₂ concentration as described below). As such, the pre-combustion CO₂ capture systems can utilize physical absorption (physisorption) solvents rather than the chemical absorption solvents described earlier for post-combustion processes. Physical absorption has the benefit of relying on weak intermolecular interactions and, as a result, the absorbed CO₂ can often be released (desorbed) by reducing the pressure rather than by adding heat. Pre-combustion capture systems have been used widely in industrial processes such as natural gas processing.

Figure 5 is a simplified process schematic for pre-combustion CO₂ capture. Components of the pre-combustion CO₂ capture system include a water-gas shift (WGS) reactor, syngas cooler (to achieve optimum temperature for the CO₂ separation step), CO₂ separation system, and compressor needed to raise the captured CO₂ to pipeline pressure.

Figure 5. Pre-Combustion CO₂ Capture for an IGCC Power Plant (NETL, 2015d)



In preparation for pre-combustion CO₂ capture, the amount of CO₂ in the syngas 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 H₂ and CO₂ according to the following catalytic reaction:

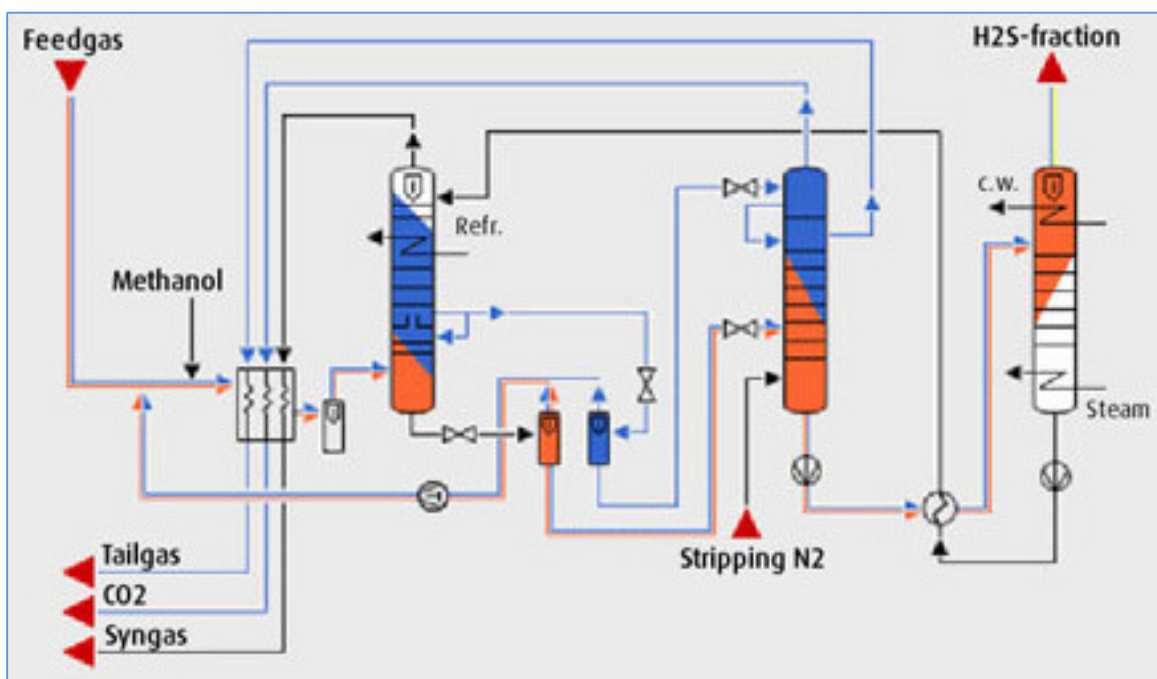


A WGS reactor is typically a fixed-bed reactor containing shift catalysts to convert CO and water into additional H₂ and CO₂. The resulting CO₂ contained in the syngas is then separated from the H₂-enriched syngas which is used for combustion in a combined-cycle turbine system for electricity generation. The CO₂ separation process uses a physical solvent, solid sorbent, or membrane to separate the CO₂ from the syngas. Sulfur compounds and CO₂ can be removed either simultaneously or selectively (in a subsequent sulfur recovery step), depending on the shifted syngas composition and conditions, as well as the end fuel gas specifications. Contrary to the post-combustion capture flue gas, the IGCC syngas can contain a high concentration of CO₂ (at high partial pressure) and is pressurized. This allows the use of physical absorbents that require much less added energy to release the captured CO₂ and require less compression to get to pipeline standards. The lower volume of syngas to be handled results in smaller equipment sizes and lower capital costs. (Interagency Task Force, 2010); NETL 2013)

The current state-of-the-art pre-combustion CO₂ capture technologies that could be applied to IGCC systems (the glycol-based Selexol™ process and the methanol-based Rectisol® process) employ physical solvents that preferentially absorb CO₂ from the syngas mixture. Other CO₂ separation processes that have yet to be built for full-scale IGCC power plants include the pyrrolidone-based Purisol process and the polypropylene carbonate-based Fluor solvent (Interagency Task Force, 2010). Several Rectisol and Selexol systems are in use at commercial scale. For example, the Rectisol system is used for CO₂ capture at the Dakota Gasification Company's substitute natural gas (SNG) plant in North Dakota, which is designed to remove approximately 1.5 million tons of CO₂ per year from the syngas. The CO₂ is purified, transported via pipeline and injected into the Weyburn oilfield in Saskatchewan, Canada (NETL, 2015d).

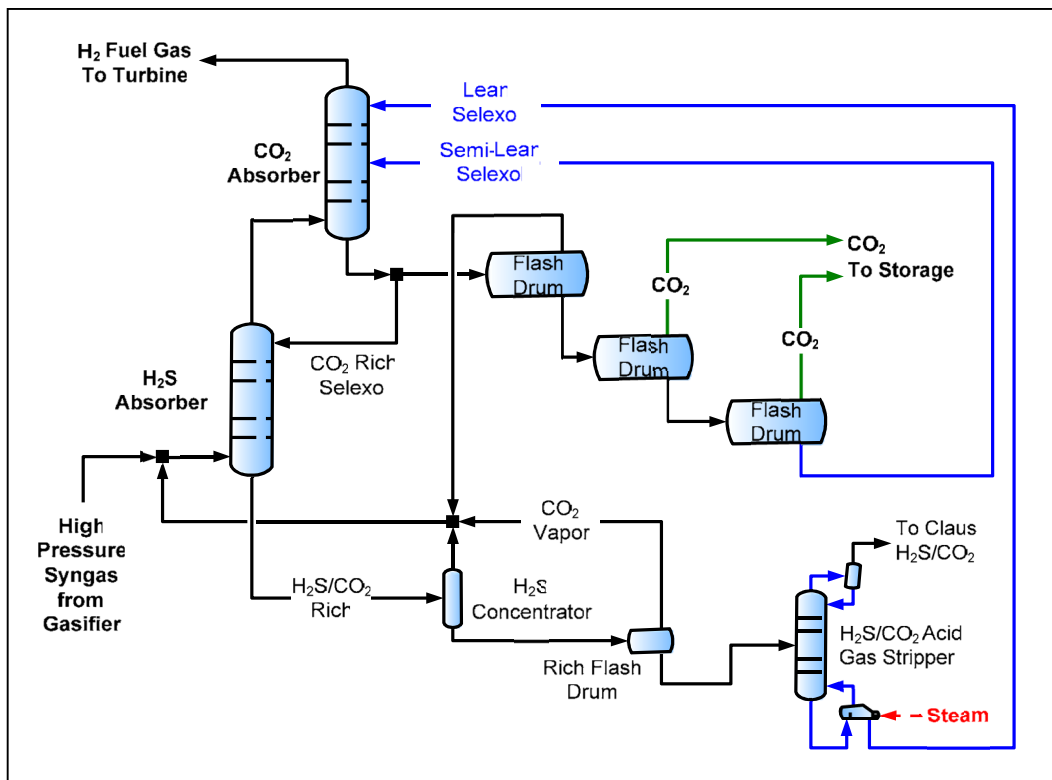
A simplified flow scheme of the Rectisol® process provided by technology vendor Linde is displayed in **Figure 6**. This is a configuration intended for dual removal of sulfur gases and CO₂ in separate fractions, resulting in a pure CO₂ product and an H₂S/COS enriched gas fraction (NETL, 2015h)

Figure 6: Rectisol Process Diagram (NETL, 2015h)



Using the two-stage Selexol™ process as an example (**Figure 7**), in the first stage, untreated syngas enters the first of two absorbers where H₂S is preferentially removed using CO₂-rich solvent from the CO₂ absorber. The gas exiting the H₂S absorber passes through the second absorber, where CO₂ is removed using both semi-lean and lean solvent streams. The treated syngas exits the absorber and is sent to the combustion turbine. The CO₂-rich solvent exits the CO₂ absorber, and a portion is sent to the H₂S absorber, while the remainder is sent to a series of flash drums for regeneration. The CO₂ product stream is obtained from the flash drums, and the semi-lean solvent is returned to the CO₂ absorber. The H₂S/CO₂-rich solvent exiting the H₂S absorber is sent to the acid gas stripper, where the absorbed gases are released using a steam heated reboiler. The acid gas from the stripper is sent to a Claus plant to produce elemental sulfur for commercial use, and the lean solvent exiting the stripper is returned to the CO₂ absorber. (Interagency Task Force, 2010)

Figure 7. Schematic Diagram of the Pre-Combustion Selexol™ CO₂ Capture Process



The Selexol™ process is being used at Southern Company's Kemper, Mississippi IGCC facility., Southern Company's Mississippi Power stated that, because the Selexol™ process has been used in industry for decades, the technical risk of its use at the Kemper IGCC facility are minimized.

For example:

The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable (Anderson, 2009).

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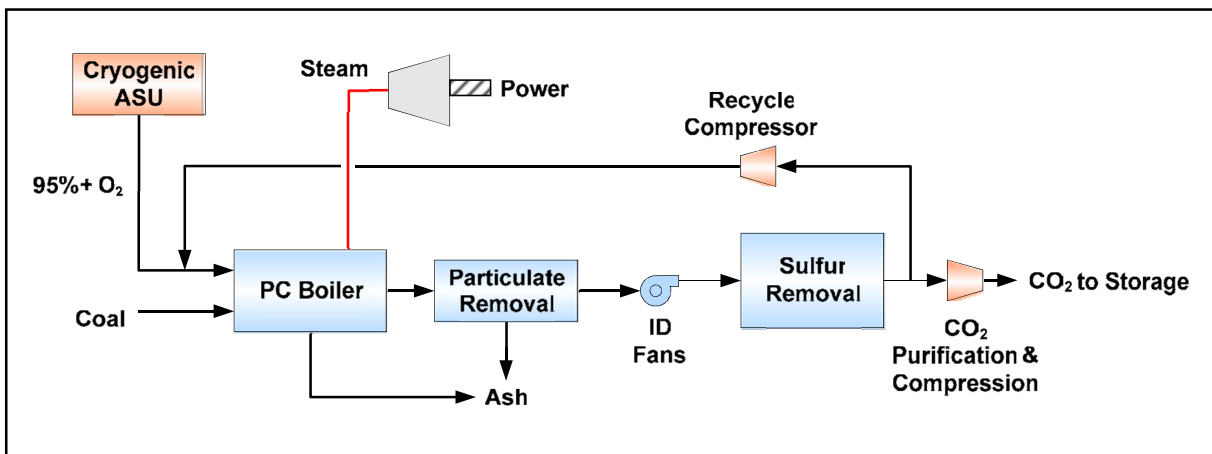
“The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.” (Mississippi Power Company, 2009).

3. Oxy-combustion CO₂ capture

Oxy-combustion (or oxy-fuel) refers to the replacement of air, either in the boiler or the gasifier, with pure oxygen (O_2). Using purified O_2 helps eliminate unwanted byproducts present in air, and also increases the CO_2 purity of the resulting syngas or flue stream, making CCS more effective.

Oxy-combustion systems for CO_2 capture rely on combusting coal (or other fuel) with relatively pure O_2 diluted with recycled CO_2 or CO_2 /steam mixtures, as shown in **Figure 8**. The primary products of combustion are water and CO_2 , with the CO_2 separated by condensing the water and removing any other gas constituents that infiltrated the combustion system (Interagency Task Force, 2010).

Figure 8. Pulverized Coal Power Plant with Oxy-Combustion CO_2 Capture
(Interagency Task Force, 2010); NETL 2013)



Oxy-combustion overcomes the technical challenge of low CO_2 partial pressure normally encountered in conventional coal combustion flue gas by producing a highly concentrated CO_2 stream (~60 percent), which is separated from water vapor by condensing the water through cooling and compression. An additional purification stage for the highly concentrated CO_2 flue gas may be necessary to produce a CO_2 stream that meets transportation and storage requirements. This purification step should have significantly less cost than a conventional post-combustion capture system, due to the high CO_2 concentration and reduced flue gas volume (Interagency Task Force, 2010).

The appeal of oxy-combustion is tempered by a few key challenges, including the capital cost and energy consumption for a cryogenic air separation unit (ASU), boiler air infiltration that dilutes the flue gas with N_2 , and excess O_2 contained in the concentrated CO_2 stream. Flue gas recycle (~70 to 80 percent) is also necessary to approximate the combustion characteristics of air, since currently available boiler materials cannot withstand the high temperatures resulting from coal combustion in pure O_2 . Consequently, the economic benefit of oxy-combustion compared to amine-based scrubbing systems is limited. (Interagency Task Force, 2010)

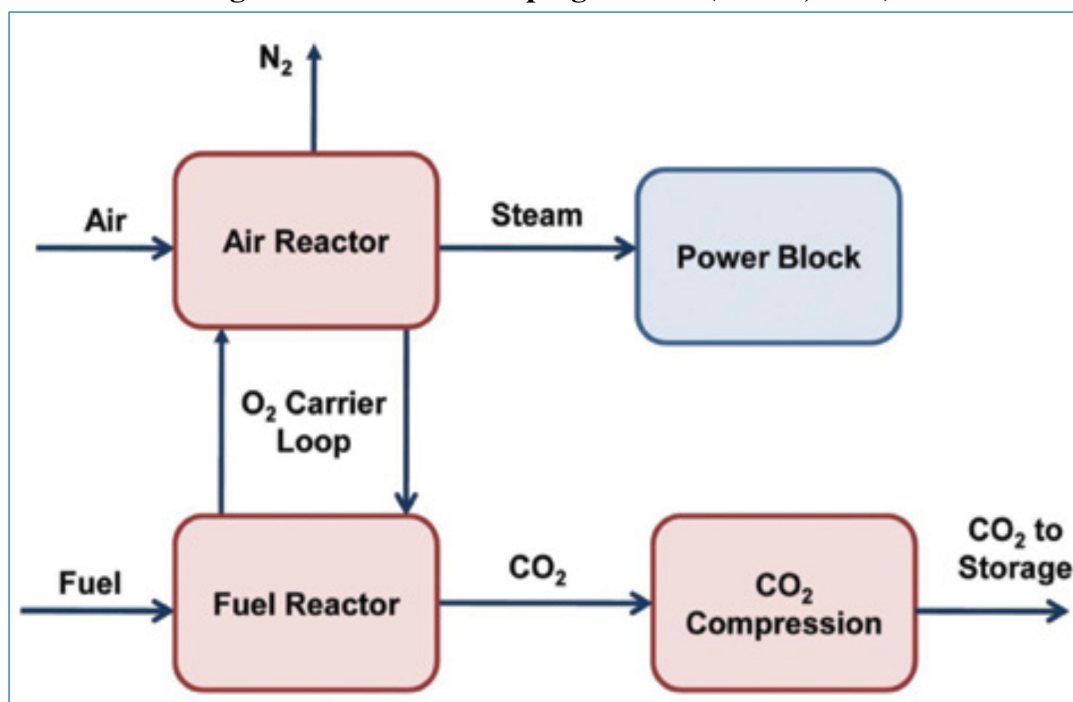
The conventional ASU is a cryogenic process that has a significant energy requirement. However, alternative oxygen separation methods are being researched for possible commercial scale development. These alternative methods include ion transport membranes (ITM), ceramic auto-thermal recovery, oxygen transport membranes, and chemical looping (EPA, 2010).

Several research institutes have investigated laboratory- and pilot-scale testing of oxy-fuel combustion, including (EPA, 2010):

- Pilot test programs for the European Enhanced Capture of CO₂ (ENCAP) program and the Advanced Development of the Coal-Fired Oxy-fuel Process with CO₂ Separation (ADECOS) program).
- A 30 MW oxy-firing pilot plant at the Schwarze Pumpe station in Spremberg, Germany.
- A 32 MW oxy-firing demonstration project in France retrofitting an existing boiler to natural gas oxy-combustion.
- A comprehensive test program using the 15 MW tangentially-fired Boiler Simulation Facility and 15 MW Industrial Scale Test Facility operated by Alstom Power, Inc., in Windsor, CT.

Chemical looping is an advanced technology similar to oxy-combustion in that it relies on combustion or gasification of coal in a N₂-free environment. However, rather than using an ASU, chemical looping involves the use of a metal oxide or other compound as an oxygen carrier to transfer O₂ from air to the fuel. **Figure 9** presents a simplified process schematic for chemical looping. Chemical looping splits combustion into separate oxidation and reduction reactions. In the fuel reactor, the oxygen carrier releases the O₂ in a reducing atmosphere and the O₂ reacts with the fuel. The carrier is then recycled back to the oxidation chamber, or air reactor, where it is regenerated by contact with air. Because air is not introduced into the fuel (combustion) reactor, the products of combustion are primarily CO₂ and H₂O. Chemical looping can be applied in either coal combustion or coal gasification processes. (NETL, 2013)

Figure 9: Chemical Looping Process (NETL, 2013)



B. CO₂ Compression

Regardless of how CO₂ is captured from a power plant, the CO₂ must be compressed to a pressure between 1,500 and 2,200 psi to be transported via pipeline and then injected into an underground storage site. As discussed in Section I.C below, compressed CO₂ is already being transported under these high pressures in a network of CO₂ pipelines used for EOR. Although compression of CO₂ to pipeline pressures is not new, research into more-advanced methods of CO₂ compression is ongoing because the compression of CO₂ requires mechanical energy and represents a potentially large auxiliary power load on the overall power plant system (NETL, 2015e).

Because CO₂ separation typically occurs at low pressure, compression is required to reduce the volume flow making transport more practical. Carbon dioxide storage sites for geological sequestration require high pressure as well. Given the high volume flows, centrifugal compressors are typically employed, especially when the captured CO₂ is produced near atmospheric pressure. The physics to compress CO₂ in a centrifugal compressor is the same as any other gas. However, CO₂ has unique characteristics compared to other gases that must be considered in the compressor design (e.g., the high volume reduction required, avoidance of water formation⁸). Its high molecular weight allows CO₂ to be liquefied at relatively high temperatures permitting hybrid compression and pumping options (NETL, 2013).

Compression of CO₂ generally occurs in multiple stages before an optimal pressure is achieved for transport of the CO₂. The gas temperature rises during each stage necessitating cooling

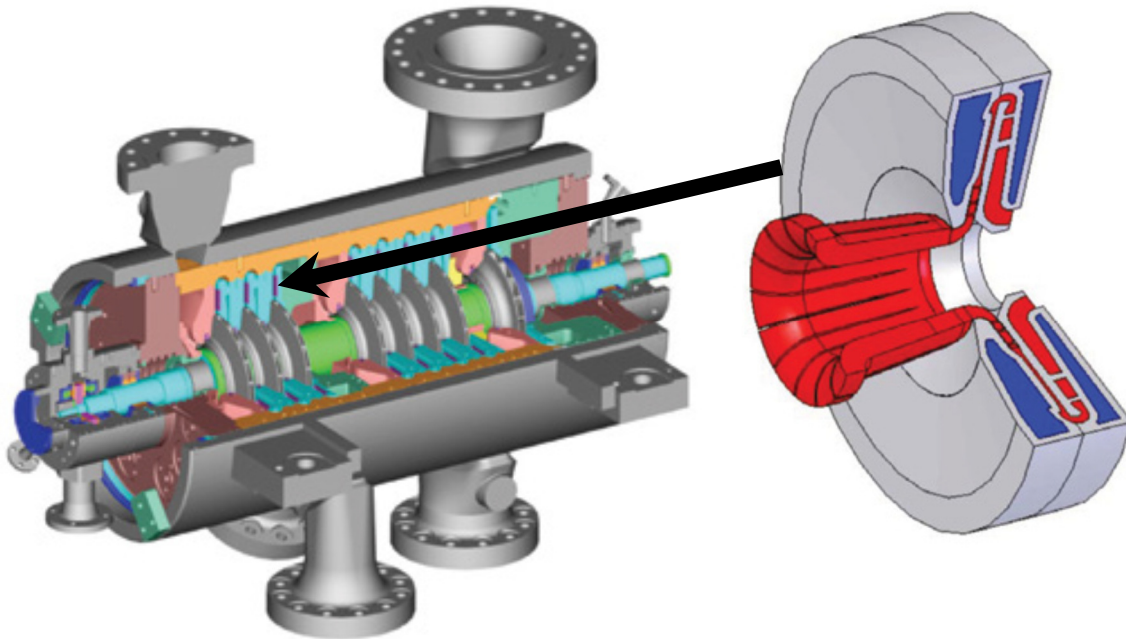
⁸ Since CO₂ dissolves in water and forms carbonic acid, which is corrosive, strict control of the water content in the CO₂ stream is essential for safe and efficient operation of the compressor

between stages (Wong, 2006). A centrifugal compressor accommodates changes in volume flow several ways. First, the frame size of the compressor can be adjusted (smaller frame size for smaller volume flows and higher pressures) (NETL, 2013). For example, in an August 2007 study conducted for NETL, CO₂ compression was accomplished using a six-stage centrifugal compressor with inter-stage cooling that required an auxiliary load of approximately 7.5 percent of the gross power output of a subcritical pressure, coal-fired power plant (NETL, 2015e).

Two types of centrifugal compressors typically are used for CO₂ compression. The first is an integrally geared compressor. It is typically driven by an electric motor that drives a large bull-gear which, in turn, drives multiple pinion gears that contain centrifugal compressors on each end. The low pressure stages run at lower speeds, and the speed increases for the higher pressure stages. The integrally geared design has a separate inlet and exit flange for each stage, permitting intercooling between each stage, which can approach isothermal compression and minimize the power requirement. The drawback of this design is the sheer size and potential reliability issues with the many bearings, seals, and unshrouded impellers.

A second type of centrifugal compressor, a beam-style compressor, is commonly used in the petrochemical and natural gas industry. It can be configured in a straight-through or back-to-back configuration (as shown in **Figure 10**). The back-to-back design permits intercooling between the two sections and intercooling between multiple compressor bodies. The beam-style compressor contains only two bearings and seals and has demonstrated reliable service in many applications including large frame sizes in liquefied natural gas (LNG) applications (up to 78-inch impellers) and high pressure (up to 15,000 psi). While some intercooling is possible, the beam-style design will typically consume more power for a given application. New DOE/NETL-sponsored research in internally cooled diaphragms is working to close this gap. In the cooled diaphragm concept, the gas is continually cooled after each stage in the flow path through the compressor. A cooling jacket insert is used in the diaphragm of each stage to provide continuous cooling. Figure 1 shows a conceptual design for an internally cooled compressor. The flow of the CO₂ is shown in red, while the cooling liquid is shown in blue.

Figure 10: Multi-Stage Back-to-Back Centrifugal Compressor (left) and Design for an Internally Cooled Compressor (right) (NETL, 2013)



A technology evaluation for CO₂ compression was provided in a report for the American Electric Power Mountaineer CCS Project (Usher, 2011). The report explained options evaluated for compressing the full CO₂ product stream from the proposed nominal 235 MWe commercial scale application of Alstom's chilled ammonia process (CAP) at American Electric Power's Mountaineer generating station, in New Haven, West Virginia. The study focused on commercially available, integrally-g geared, inter-cooled, gas compression systems. The scope of the study included all of the equipment required to compress and condition the captured CO₂ for sequestration. In the end, two arrangements were considered technically and economically feasible for implementation on the commercial scale system. Both utilize compression of the CO₂ to an intermediate condition, followed by variable-speed pumping to the final desired injection conditions. The compressor-pump arrangement allows for greater flexibility and higher operating efficiency throughout the life of the well, which is important based on the expected variability in injection pressure over the life of the injection wells.

Additional information on compressors and summaries of multiple advanced compression research projects (pilot studies) to continue improving the efficiency of CO₂ compression as part of CCS can be found in NETL 2013. Recent NETL-funded projects researching improvements to CO₂ compression relevant for CCS include the following:

- Southwest Research Institute is developing novel compression technology concepts to reduce CO₂ compression power requirements by 10 percent compared to conventional compressor designs. The basic concept is a semi-isothermal compression process where the CO₂ is continually cooled using an internal cooling jacket rather than using

conventional interstage cooling. The project has completed thermodynamic (Phase I) and prototype testing (Phase II). A full-scale demonstration of a multi-stage, internally cooled diaphragm pilot test program (Phase III) was completed in 2014.

- Lehigh University set out to use systems analysis models to study the benefits of improved thermal integration for coal-fired power plants equipped with post- or oxy-combustion CO₂ capture systems.
- Ramgen Power Systems is designing and developing a unique compressor technology based upon aerospace shock wave compression theory for use as a CO₂ compressor. A shock wave-based gas turbine engine is also being developed. Ramgen's compressor design features a rotating disk that operates at high peripheral speeds to generate shock waves that compress the CO₂. Compared to conventional compressor technologies, shock compression offers several potential advantages: high compression efficiency; high single-stage compression ratios; opportunity for waste heat recovery; and low capital cost (NETL, 2015i).

C. CO₂ Transportation Pipeline Infrastructure

Pipelines are the most economical and efficient method of transporting CO₂ from commercial CCS facilities geologic storage sinks such as saline formations, coal seams, and oil and gas fields (Interagency Task Force, 2010). Technologies for the transport of CO₂ through a regionally extensive network of CO₂ pipelines are in use today. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that in 2013 there were 5,195 miles of CO₂ pipelines operating in the United States. (PHMSA, 2015)

The design, construction, operation, and safety requirements for CO₂ pipelines are proven. Design considerations for CO₂ pipelines include pipeline material selection and fracture control; pipeline diameter and depth; valve, seal, elastomer, and pumping material selection; valve spacing; and quality considerations, such as composition of the stream. Construction requirements and standards are in place to protect pipelines from damage and to maximize the integrity of the system over its operating lifespan. See Interagency Task Force, 2010.

Existing and new CO₂ pipelines are comprehensively regulated by the Department of Transportation's Pipeline Hazardous Material Safety Administration. The regulations govern pipeline design, construction, operation and maintenance, and emergency response planning. See generally 49 CFR 195.2. Additional regulations address pipeline integrity management by requiring heightened scrutiny to assure the quality of pipeline integrity in areas with a higher potential for adverse consequences. See 49 CFR 195.450 and 195.452.

In addition to the PHMSA Hazardous Liquid Pipeline Safety Regulations (49 CFR Part 195) requirements, industry design standards from the American Society of Mechanical Engineers (ASME) and the American Petroleum Institute (API), which are incorporated into 49 CFR Part 195 by reference, are in place to reduce pipeline risks from CO₂ pipeline systems. (Interagency Task Force, 2010)

On-site pipelines are not subject to the Department of Transportation standards, but rather adhere to the Pressure Piping standards of the American Society of Mechanical Engineers (ASME B31), which the EPA has found would ensure that piping and associated equipment meet certain quality and safety criteria sufficient to prevent releases of CO₂, such that certain additional requirements were not necessary (See 79 FR 358-59 (Jan. 3, 2014)). These existing controls over CO₂ pipelines assure protective management, guard against releases, and assure that captured CO₂ will be securely conveyed to a sequestration site.

D. Geologic Sequestration

Geologic sequestration (GS) – the long-term containment of a CO₂ stream in subsurface geologic formations – is based on a demonstrated understanding of the processes that affect CO₂ fate in the subsurface. Sequestration is already well proven. CO₂ has been retained underground for eons in geologic (natural) repositories and the mechanisms by which CO₂ is trapped underground are well understood. The physical and chemical trapping mechanisms, along with the regulatory requirements and safeguards of the Underground Injection Control (UIC) Program and complementary monitoring and reporting requirements of the Greenhouse Gas Reporting Program (GHGRP), together ensure that sequestered CO₂ will remain secure and provide the monitoring to identify and address potential leakage using Safe Drinking Water Act (SDWA) and Clean Air Act (CAA) authorities.

Subsurface formations suitable for GS of CO₂ captured from affected EGUs are geographically widespread throughout most parts of the United States. GS is technically feasible based on a demonstrated understanding of the processes that affect CO₂ fate in the subsurface; these processes can vary regionally as the subsurface geology changes. GS occurs through a combination of trapping mechanisms which are well understood and proven:

1. Structural and stratigraphic trapping is a physical trapping mechanism that occurs when the CO₂ reaches a stratigraphic zone with low permeability (i.e., geologic confining system) that prevents further upward migration.
2. Residual trapping is a physical trapping mechanism that occurs as residual CO₂ is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces.
3. Adsorption trapping is another physical trapping mechanism that occurs when CO₂ molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane.
4. Solubility trapping is a geochemical trapping mechanism where a portion of the CO₂ from the pure fluid phase dissolves into native ground water and hydrocarbons.
5. Mineral trapping is a geochemical trapping mechanism that occurs when chemical reactions between the dissolved CO₂ and minerals in the formation lead to the precipitation of solid carbonate minerals.

The effectiveness of long-term trapping of CO₂ has been demonstrated by natural analogs in a range of geologic settings where CO₂ has remained trapped for millions of years (Holloway et al, 2007). For example, CO₂ has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi (IPCC, 2005). Other examples of natural CO₂ sources include Bravo Dome and McElmo Dome in Colorado and New Mexico, respectively. These

natural storage sites are themselves capable of holding volumes of CO₂ that are larger than the volume of CO₂ expected to be captured from a fossil fuel-fired EGU. In 2010, the DOE estimated current CO₂ reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome (DiPietro, et. al, 2012).

GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO₂ increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). Both deep saline and oil and gas formation types are widely available in the United States. Details on the geographic availability of geologic sequestration are provided in EPA, 2015.

Deep saline formations offer the greatest potential storage resource and capacity. These formations are sedimentary rock layers that are generally more than 800 meters deep and are saturated with waters or brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS) (Interagency Task Force, 2010). Deep saline formations are found throughout the United States, and many of these formations may be overlain by laterally extensive, impermeable formations that restrict upward movement of injected CO₂.

Eight Department of Energy Regional Carbon Sequestration Partnership (RCSP) “Development Phase” projects have been initiated and five of the eight projects are injecting or have completed CO₂ injection into deep saline formations. Three of these projects have already injected more than one million metric tons each, and one, the Cranfield Site, injected over eight million metric tons of CO₂ between 2009 and 2013 (NETL, 2013b). Various types of technologies for monitoring CO₂ in the subsurface and air have been employed at these projects, such as seismic methods (crosswell seismic, 3-D and 4-D seismic, and vertical seismic profiling), atmospheric CO₂ monitoring, soil gas sampling, well and formation pressure monitoring, and surface and ground water monitoring.⁹ No CO₂ leakage has been reported from these sites, which further supports the availability of effective GS.

Enhanced oil recovery (EOR) is a technique that is used to increase the production of oil. Approaches used for EOR include steam injection, injection of specific fluids such as surfactants and polymers, and gas injection including nitrogen and CO₂. EOR using CO₂, sometimes referred to as “CO₂ flooding” or CO₂-EOR, involves injecting CO₂ into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. The crude oil and CO₂ mixture is then recovered and sent to a separator where the crude oil is separated from the gaseous hydrocarbons, native formation fluids, and CO₂. The gaseous CO₂-rich stream then is typically dehydrated, purified to remove hydrocarbons, re-compressed, and re-injected into the reservoir to further enhance oil recovery. Not all of the CO₂ injected into the oil reservoir is recovered and re-injected. As the CO₂ moves from the injection point to the production well, some of the CO₂ becomes trapped in the small pores of the rock, or is dissolved in the oil and water that is not recovered. The CO₂ that remains in the reservoir is not mobile and becomes sequestered.

⁹ A description of the types of monitoring technologies employed at RCSP projects can be found at DOE 2015a.

The amount of CO₂ used in an EOR project depends on the volume and injectivity of the reservoir that is being flooded and the length of time the EOR project has been in operation. Initially, all of the injected CO₂ is newly received. As the project matures, some CO₂ is recovered with the oil and the recovered CO₂ is separated from the oil and recycled so that it can be re-injected into the reservoir in addition to new CO₂ that is received. If an EOR operator will not require the full volume of CO₂ available from an EGU, the EGU has other options such as sending the CO₂ to other EOR operators, or sending it to deep saline formation GS facilities.

CO₂ used for EOR may come from anthropogenic or natural sources. The source of the CO₂ does not impact the effectiveness of the EOR operation. CO₂ capture, treatment and processing steps provide a concentrated stream of CO₂ in order to meet the needs of the intended end use. CO₂ pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO₂ and take into account CO₂ composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications related to the composition of the CO₂ stream. The regulatory requirements and company specifications ensure EOR operators receive a known and consistent CO₂ stream.

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 over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States (Koottungal, 2014). More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO₂ injection and monitoring technologies, which are needed for safe and secure GS that can be used for deployment of CCS across geographically diverse areas.

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations (Kuuskraa, 2011). DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 18 billion metric tons of anthropogenic CO₂ and increase total oil production by 67 billion barrels (Kuuskraa, 2011). The study found that one of the limitations to expanding CO₂ use in EOR is the lack of availability of CO₂ in areas where reservoirs are most amenable to CO₂ flooding. DOE's Carbon Utilization and Storage Atlas identifies 29 states with oil reservoirs amenable to EOR, 12 of which currently have active EOR operations (NACAP, 2012). A comparison of the current states with EOR operations and the states with potential for EOR shows that an opportunity exists to expand the use of EOR to regions outside of current areas. The availability of anthropogenic CO₂ in areas outside of current sources could drive new EOR projects by making more CO₂ locally available.

Several EOR sites, which have been operated for years to decades, have been studied to evaluate the viability of safe and secure long-term sequestration of injected CO₂. Examples are identified below.

- CO₂ has been injected in the SACROC Unit in the Permian basin since 1972 for EOR purposes. One study evaluated a portion of this project, and estimated that the injection operations resulted in final sequestration of about 55 million tons of CO₂ (Han, 2010). This study used modeling and simulations, along with collection and analysis of seismic surveys, and well logging data, to evaluate the ongoing and potential CO₂ trapping occurring through various mechanisms. The monitoring at this site demonstrated that CO₂ can become trapped in geologic formations. In a separate study in the SACROC Unit, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO₂ leakage in the shallow freshwater aquifers (Romanak, 2010). No evidence of leakage was detected.
- The International Energy Agency Greenhouse Gas Programme conducted an extensive monitoring program at the Weyburn oil field in Saskatchewan between 2000 and 2010 (the site receiving CO₂ captured by the Dakota Gasification synfuel plant discussed later in this document). During that time over 16 million metric tons of CO₂ were safely sequestered as evidenced by soil gas surveys, shallow groundwater monitoring, seismic surveys and wellbore integrity testing. An extensive shallow groundwater monitoring program revealed no significant changes in water chemistry that could be attributed to CO₂ storage operations (Roston, 2010). The International Energy Agency Greenhouse Gas Programme developed a best practices manual for CO₂ monitoring at EOR sites based on the comprehensive analysis of surface and subsurface monitoring methods applied over the 10 years (Hitchon, 2012).
- The Texas Bureau of Economic Geology also has been testing a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi (Gulf Coast Carbon Center, 2015). As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO₂ into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology is currently evaluating the results of several monitoring techniques employed at the Cranfield project and preliminary findings indicate no impact to groundwater (Gulf Coast Carbon Center, 2015). The project also demonstrates the availability and effectiveness of many different monitoring techniques for tracking CO₂ underground and detecting CO₂ leakage to ensure CO₂ remains safely sequestered.

CO₂ may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.¹⁰ Enhanced coalbed methane recovery is the process of injecting and storing CO₂ in unmineable

¹⁰ Other types of opportunities include organic shales and basalt.

coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO₂ relative to the methane that is naturally found on the surfaces of coal. When CO₂ is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively “locks” the CO₂ to the coal, where it remains stored.

In 2010, the EPA finalized an effective and coherent regulatory framework to ensure the long-term, secure and safe storage of large volumes of CO₂. The EPA developed these Underground Injection Control (UIC) Class VI well regulations under authority of the Safe Drinking Water Act (SDWA) to facilitate injection of CO₂ for GS, while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDWs). The Class VI regulations are built upon 35 years of federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The EPA and states have decades of UIC experience with the Class II program, which provides a regulatory framework for the protection of USDWs for CO₂ injected for purposes of EOR.

In addition, to complement both the Class VI and Class II rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO₂ capture, underground injection, and geologic sequestration through the GHGRP. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

Under SDWA, the EPA developed the UIC Program to regulate the underground injection of fluids in a manner that ensures protection of USDWs. UIC regulations establish six different well classes that manage a range of injectates (e.g., industrial and municipal wastes; fluids associated with oil and gas activities; solution mining fluids; and CO₂ for geologic sequestration) and which accommodate varying geologic, hydrogeological, and other conditions.

In 2010, the EPA established a new class of well, Class VI. Class VI wells are used to inject CO₂ into the subsurface for the purpose of long-term sequestration. See 75 FR 77230 (Dec. 10, 2010). This rule accounts for the unique nature of CO₂ injection for large-scale GS. Specifically, the EPA addressed the unique characteristics of CO₂ injection for GS including the large CO₂ injection volumes anticipated at GS projects, relative buoyancy of CO₂, its mobility within subsurface geologic formations, and its corrosivity in the presence of water. The UIC Class VI rule was developed to facilitate GS and ensure protection of USDWs from the particular risks that may be posed by large scale CO₂ injection for purposes of long-term GS. The Class VI rule establishes technical requirements for the permitting, geologic site characterization, area of review (i.e., the project area) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, site closure, and financial responsibility for the purpose of protecting USDWs.

The EPA has issued Class VI permits for six wells under two projects.

- In September 2014, a UIC Class VI injection well permit (to construct) was issued by the EPA to Archer Daniels Midland for an ethanol facility in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mount Simon geologic formation, a deep saline formation, to accept and retain industrial scale volumes of

- CO₂ for permanent GS. The permitted well has a projected operational period of five years, during which time 5.5 million metric tons of CO₂ will be injected into an area of review with a radius of approximately 2 miles.¹¹ Following the operational period, Archer Daniels Midland plans a post-injection site care period of ten years.¹²
- In September 2014, the EPA also issued four Class VI injection well permits (to construct) to the FutureGen Industrial Alliance project in Jacksonville, Illinois, which proposed to capture CO₂ emissions from a coal-fired power plant in Meredosia, Illinois and transport the CO₂ by pipeline approximately 30 miles to the deep saline GS site.¹³ The Alliance proposed to inject a total of 22 million metric tons of CO₂ into an area of review with a radius of approximately 24 miles over the 20 year life of the project, with a post-injection site care period of fifty years.¹⁴

The CO₂ injection wells used for EOR are regulated through the UIC Class II program. 40 CFR §144.6(b). CO₂ storage associated with Class II wells is a common occurrence and CO₂ can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery. UIC Class II regulations issued under section 1421 of SDWA provide minimum federal requirements for site characterization, area of review, well construction (e.g., casing and cementing), well operation (e.g., injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational conditions that could lead to loss of injectate and migration into USDWs.

In addition, to complement the Class II and VI rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO₂ capture, underground injection, and geologic sequestration through the Greenhouse Gas Reporting Program (GHGRP) found in 40 CFR Part 98. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

Subpart PP of the GHGRP (40 CFR 98.420 - 98.428) provides requirements to account for CO₂ supplied to the economy. This subpart requires affected facilities with production process units that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications or that capture and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground to report the mass of CO₂ captured and supplied to the economy. CO₂ suppliers are required to report the annual quantity of CO₂ transferred offsite and its end use, including GS.

Reporting under subpart RR (40 CFR 98.440 - 98.449) is required for all facilities that have received a Class VI UIC permit for injection of CO₂. Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic

¹¹ <http://www.epa.gov/region5/water/uic/adm/>. In addition, Archer Daniels Midland received a UIC Class VI injection well permit for a second well in December 2014. Archer Daniels Midland had been injecting CO₂ at this well since 2011 under a UIC Class I permit issued by the Illinois EPA.

¹² <http://www.epa.gov/region5/water/uic/adm/>.

¹³ After permit issuance, and for reasons unrelated to the permitting proceeding, DOE initiated a structured closeout of federal support for the FutureGen project in February 2015. However, these are still active Class VI permits.

¹⁴ <http://www.epa.gov/r5water/uic/futuregen/>.

information on the mass of CO₂ received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO₂ sequestered using a mass balance approach; and report annual monitoring activities. The subpart RR MRV plan includes five major components:

1. A delineation of monitoring areas based on the CO₂ plume location. Monitoring may be phased in over time.
2. An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO₂ through these pathways. The monitoring program will be designed to address the risks identified.
3. A strategy for detecting and quantifying any surface leakage of CO₂ in the event leakage occurs. Multiple monitoring methods and accounting techniques can be used to address changes in plume size and risks over time.
4. An approach for establishing the expected baselines for monitoring CO₂ surface leakage. Baseline data represent pre-injection site conditions and are used to identify potential anomalies in monitoring data.
5. A summary of considerations made to calculate site-specific variables for the mass balance equation. Site-specific variables may include calculating CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment, and considerations for calculating CO₂ from produced fluids.

Monitoring programs conducted at international GS projects provide examples where large volumes of CO₂ have been safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected from CCS at EGUs. This experience has also demonstrated the value and efficacy of monitoring programs to determine the location of CO₂ in the subsurface and detect potential leakage through the presence of CO₂ in the shallow subsurface, near surface and air.

The Sleipner CO₂ Storage Project is located at an offshore gas field in the North Sea where CO₂ must be removed from the natural gas in order to meet customer requirements and reduce costs. The project began injecting CO₂ into the deep subsurface in 1996. The single offshore injection well injects approximately 1 million metric tons per year into a thick, permeable sandstone above the gas producing zone. Approximately 15 million metric tons of CO₂ have been injected since inception. Many U.S. and international organizations have conducted monitoring in conjunction with the Sleipner CO₂ Storage Project. The location and dimensions of the CO₂ plume have been measured numerous times using 3-dimensional seismic monitoring since the 1994 pre-injection survey. The monitoring data have demonstrated that although the plume is behaving differently than initially modeled due to thin layers of impermeable shale that were not initially identified in the reservoir model, the CO₂ remains trapped in the injection zone. Numerous other techniques have been successfully used to monitor CO₂ storage at Sleipner. The research and monitoring at Sleipner demonstrates the value of a comprehensive approach to site characterization, computational modeling and monitoring, as is required under UIC Class VI rules. The experience at Sleipner demonstrates that large volumes of CO₂, of the same order of magnitude expected for an EGU, can be safely injected and stored in saline reservoirs over an extended period.

Snøhvit is another large offshore CO₂ storage project, located at a gas field in the Barents Sea. Like Sleipner the natural gas must be treated to reduce high levels of CO₂ to meet processing standards and reduce costs. Gas is transported via pipeline 95 miles to a gas processing and liquefied natural gas plant and the CO₂ is piped back offshore for injection. Approximately 0.7 million metric tons per year CO₂ are injected into permeable sandstone below the gas reservoir. Between 2008 and 2011, the operator observed pressure increases in the injection formation (Tubaen Formation) greater than expected and conducted time lapse seismic surveys and studies of the injection zone and concluded that the pressure increase was mainly caused by a limited storage capacity in the formation (Grude et al., 2014). In 2011, the injection well was modified and injection was initiated in a second interval (Stø Formation) in the field to increase the storage capacity.

CO₂ from the Great Plains Synfuels plant in North Dakota has been injected into the Weyburn oil field in Saskatchewan Canada since 2000. The Great Plains Synfuels plant is discussed later in this document. It is anticipated that approximately 40 million metric tons of CO₂ will be permanently sequestered over the lifespan of the project. Extensive monitoring by U.S. and international partners has demonstrated that no leakage has occurred.

At the In Salah CO₂ storage project in Algeria, CO₂ is removed from natural gas produced at three nearby gas fields in order to meet export quality specification. The CO₂ is transported by pipeline approximately 3 miles to the injection site. Three horizontal wells are used to inject the CO₂ into the down-dip aquifer leg of the gas reservoir approximately 6,200 feet deep. Between 2004 and 2011 over 3.8 million metric tons of CO₂ were stored. Injection rates in 2010 and 2011 were approximately 1 million metric tons per year. Storage integrity has been monitored by several US and international organizations and the monitoring program has employed a wide range of geophysical and geochemical methods, including time lapse seismic, microseismic, wellhead sampling, tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite data. The data have been used to support periodic risk assessments during the operational phase of the project. In 2010 new data from seismic, satellite and geomechanical models were used to inform the risk assessment and led to the decision to reduce CO₂ injection pressures due to risk of vertical leakage into the lower caprock, and risk of loss of well integrity. The caprock at the site consisted of main caprock units, providing the primary seal, and lower caprock units, providing additional buffers. There was no leakage from the well or through the caprock, but the risk analysis identified an increased risk of leakage, therefore, the aforementioned precautions were taken. Additional analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO₂ injection in June 2011. No leakage has occurred and the injected CO₂ remains safely stored in the subsurface. The decision to proceed with safe shutdown of injection resulted from the analysis of seismic and geomechanical data to identify and respond to storage site risk. The Salah project demonstrates the value of developing an integrated and comprehensive set of baseline site data prior to the start of injection, and the importance of regular review of monitoring data.

Even though potentially adverse conditions were identified at some projects (In Salah and Snøhvit), there were no releases to air and the monitoring systems were effective in identifying the issues in a timely manner, and these issues were addressed effectively. In each case, the site-specific characteristics were evaluated on a case-by-case basis to select a site where the geologic

conditions are suitable to ensure long-term, safe storage of CO₂. Each project was designed to address the site-specific characteristics and operated to successfully inject CO₂ for safe storage.

In summary, the different regulatory components, already in place, assure the safety and effectiveness of GS. The effective regulatory structure complements the analysis of the technical feasibility of GS, which together affirm that the technical feasibility of GS is adequately demonstrated.

E. Alternatives to Geologic Sequestration

Potential alternatives to storing CO₂ in geologic formations are emerging. Applications where captured anthropogenic CO₂ is converted to a useable product may offer the opportunity to offset the cost of CO₂ capture. Examples of CO₂ utilization include:

Carbonation/mineralization: Alkaline earth oxides react with CO₂ to create insoluble carbonates. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications such as for use in construction or cement manufacture. For example:

- Precipitated calcium carbonate (PCC) is produced through a chemical reaction process that uses calcium oxide (quicklime), water, and CO₂. Some pulp and paper manufacturers supply anthropogenic CO₂ from process exhausts to nearby PCC producers, which in turn supply PCC for use in paper manufacturing (40 CFR part 98, subpart PP).
- The combination of magnesium oxide and CO₂ results in a precipitation reaction where the CO₂ becomes mineralized.
- The Skyonics Skymine project, which opened its demonstration project in October 2014, captures over 75,000 tons of CO₂ annually from a San Antonio, Texas, cement plant and converts the CO₂ into other products, including sodium carbonate, sodium bicarbonate, hydrochloric acid and bleach (Skymine, 2015).
- Other companies – including Calera and New Sky – also offer commercially available technology for the beneficial use of captured CO₂ (Calera, 2015; New Sky, 2015).

Bio-fuel production using algae: Plants convert CO₂ and water into starch using sunlight during the photosynthesis process. Although more advanced plants are not very effective in conversion of large quantities of CO₂, micro-algae can use high concentrations of CO₂ to create starch. The biomass product can be used to recycle CO₂ into valuable industrial fuel such as methane, methanol, hydrogen and bio-diesel.

Fuel production: Most carbon-based fuels are made up of carbon, hydrogen, and oxygen. CO₂ can be hydrogenated in the presence of a catalyst to create low-carbon-chain fuel such as methanol. Procuring hydrogen requires energy for hydrolysis of water or partial oxidation of natural gas.

Chemical synthesis: Ceramics, fertilizers, rubber, and many other small-scale industries require CO₂ at some stage of their manufacturing process. The largest use of CO₂ in this area is in fertilizer plants, where CO₂ is captured from the exhaust gases of NH₃ reformer units and used to manufacture urea.

CO₂ utilization is a promising research area. There are currently no plenary systems of regulatory control and GHG reporting for these approaches, as there are for geologic sequestration. Nonetheless, CO₂ utilization technologies not only show promise, but could potentially be demonstrated to show permanent storage of CO₂.

F. Continuing Research and Policy Development

Climate science and climate change mitigation options – including CCS - are the subject of great academic interest and a large body of academic literature on the subjects exists. In addition, other research organizations (e.g., U.S. national laboratories and others) have also published studies on these subjects.

The Thomson Reuters *Web of Science* database is a comprehensive source of academic publications from around the world. As a metric to gauge global interest and progress in CCS technologies, EPA conducted a search of the database using the keywords "carbon capture" and "carbon capture and sequestration" and searching by the title of the paper. After conducting the search, the data was sorted by year in order to create a timeline of CCS development. The results of this search are shown in **Figure 11** below. The number of publications regarding CCS has grown dramatically in the past decade, from only 7 papers in 2004 to 147 publication in 2014, with a peak of 205 publications in 2013.

In order to corroborate this trend, EPA also conducted a search using the U.S. patent database, using the keywords "Carbon Capture". The results of this search were segmented by year, and are shown in **Figure 12** below. As with the publications, the number of patents issued regarding CCS technology has increased rapidly over the past decade, beginning in 2007. The number of patents issued peaked in 2014, with 160 patents issued. Both The U.S. patent office and Thomson Reuters confirm that industry and academia are both working towards technological advancements in all stages of CCS.

Figure 11. Number of Publications Regarding CCS per Year

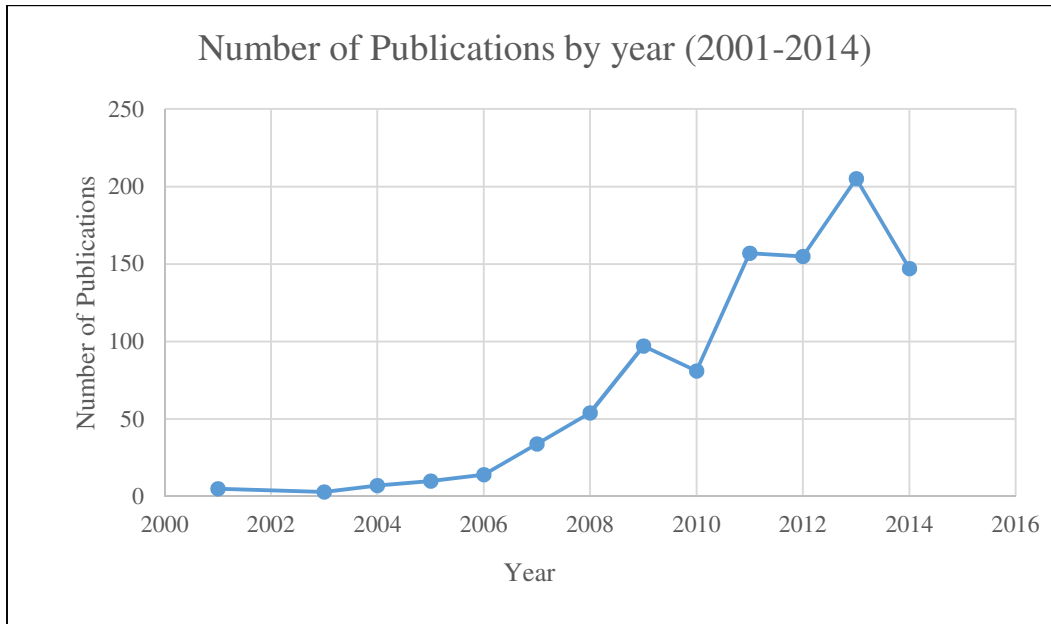
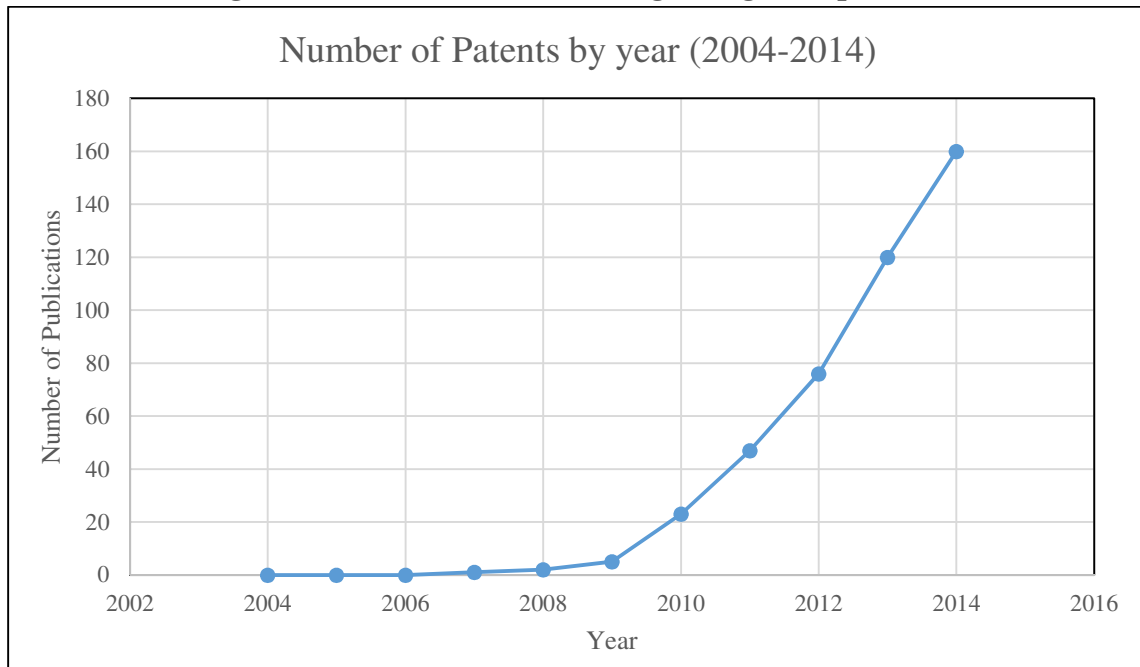


Figure 12. Number of Patents Regarding CCS per Year



Research is underway to reduce CO₂ capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO₂ from fossil fuel energy plants compared to currently available capture technologies. The large-

scale CO₂ capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies. The CCS Global Consortium and National Carbon Capture Center are examples of organizations dedicated to accelerating commercial CCS.

SaskPower created the CCS Global Consortium (<http://www.saskpowerccs.com/consortium/>) to share the knowledge and experience from the Boundary Dam Unit #3 facility with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology development through the creation of the Shand Carbon Capture Test Facility (CCTF) (SaskPower, 2015a). The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

The National Carbon Capture Center at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama is a consortium between DOE/NETL and electric power producers offering a world-class test facility and a highly specialized staff to accelerate the commercialization of advanced technologies and enable fossil-fuel based power plants to achieve near-zero emissions. The NCCC was established in 2009 to build on the experience, expertise, and infrastructure in place at the PSDF, which has been in operation since 1996. In undertaking its mission, the NCCC is involved in a range of activities to develop the most promising technologies for future commercial deployment, thereby maximizing the impact of project funds. A large portion of NCCC research is focused on development of post-combustion CO₂ capture for incorporation into pulverized coal power plants and pre-combustion CO₂ capture for integration into the new generation of coal gasification power plants. Post-combustion and pre-combustion CO₂ capture work has included multiple projects, such as testing of solvents, enzymes, gas separation membranes, sorbents, and catalysts, as well as other novel processes. The testing has supported technology developers from both industry and universities, and in many cases has yielded the bases for process improvements and scale-ups (Northington, et al., 2012).

In addition to research underway to accelerate commercial carbon capture, research is also underway to advance commercial use of geologic sequestration. The DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to deploy large-scale field projects in different geologic settings across the country to demonstrate that GS can be achieved safely, permanently, and economically at large scales. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO₂ emissions, 97 percent of industrial CO₂ emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the United States potentially available for GS (DOE, 2015a). The seven partnerships include more than 400 organizations spanning 43 states (and four Canadian provinces) (DOE, 2015a). RCSP project objectives are to inject at least one million metric tons of CO₂. In April 2015, DOE announced that CCS projects supported by the department have safely and permanently stored 10 million metric tons of CO₂ (DOE, 2015b).

In addition to Federal initiatives, multiple states have established emission performance standards or other measures to limit emissions of GHGs from new EGUs. The emission levels established by these standards would effectively require CCS. For example,

- In September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO₂/MWh.
- In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any base load electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Base load generation facilities must initially comply with an emission limit of 1,100 lb CO₂/MWh.
- In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating base load electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO₂/MWh, and prohibited utilities from entering into long-term purchase agreements for base load electricity with out-of-state facilities that do not meet that standard.
- New York established emission standards of CO₂ at 925 lb CO₂/MWh for new and expanded base load fossil fuel-fired plants.
- In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO₂ emissions performance standard for EGUs in the state. House Bill 25 prohibits the state Public Utility Commission from approving new EGUs primarily fueled by coal unless a minimum of 50 percent of the CO₂ produced by the facility is captured and sequestered.
- On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

II. Facilities Utilizing CCS

Many industries, including the power generation industry, are beginning to incorporate CCS into their plant designs. In the U.S. and abroad, multiple CCS projects are in various stages of development, from research and planning to currently operating pilot- and full-scale systems. Some of these projects are described in greater detail below. It should be noted that this section only highlights some of the major examples of CCS implementation, and should not be considered an exhaustive list of all CCS projects.

A. Post-combustion

Table 2 lists seven facilities that have experience with post-combustion CO₂ capture projects, including six EGUs and one soda ash production facility. Each project is briefly summarized in the following subsections.

Table 2. Summary of Post-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
AEP/Alstom - Mountaineer Project	Domestic	New Haven, West Virginia	EGU	Coal-fired power plant (30 MW slipstream)	Full (>90%) CCS	2009	100,000	Pipeline	GS	Mount Simon, 1.5 miles in depth
AES - Shady Point	Domestic	Panama, Oklahoma	EGU	Coal-fired power plant (320 MW)	Partial (<10%)	1991	66,000	Not transported	Purified and sold as food-grade CO2	Multiple Locations
AES - Warrior Run	Domestic	Cumberland, Maryland	EGU	Coal-fired power plant (180 MW)	Partial (<10%)	2000	110,000	Not transported	Purified and sold as food-grade CO2	Multiple Locations
Petra Nova - W.A. Parish	Domestic	Houston, Texas	EGU	Coal-fired power plant (240 MW slip steam)	Full (>90%) CCS	2017 (under construction)	1,600,000	Pipeline	EOR	Hilcorp's West Ranch Oil Field
SaskPower - Boundary Dam Unit #3	International	Estevan, Saskatchewan, Canada	EGU	IGCC power plant (110 MW)	Full (>90%) CCS	October, 2014	1,000,000	Pipeline	EOR	Weyburn EOR, 40 miles away

Searles Valley Minerals	Domestic	Trona, California	Soda Ash	Coal-fired power plant generating steam/power for onsite use	Post-combustion amine scrubbing	1978	264,898	NA: used onsite	Other use: carbonation of brine in soda ash process	Not specified
Fluor Corp. – Bellingham	Domestic	Bellingham, Massachusetts	EGU	Natural Gas-fired power plant (40 MW slipstream of a 320 MW plant)	Full (>90%) CCS	1991 (2005)	100,000	Not transported	Purified and sold as food-grade CO ₂	Multiple Locations

1. AEP/Alstom - Mountaineer Project

AEP began a pilot CCS project at its Mountaineer Plant in New Haven, West Virginia in September, 2009. The project was a 20 MWe slipstream of the 1,300 MW plant, capturing 100,000 metric tons CO₂/year which was sequestered 1.5 miles underground in the neighboring Mount Simon Sandstone deposits. The project was initially planned to expand to 235 MW, with 150,000 metric tons CO₂/year, a 90% capture rate; however, uncertain federal climate regulation discouraged AEP from continuing the project (MIT, *Mountaineer Fact Sheet*, 2015).

2. AES – Shady Point/Warrior Run

The Shady Point (Panama, OK) and Warrior Run (Cumberland, MD) power plants use circulating fluidized bed reactors, and amine scrubbers developed by ABB/Lummus to capture CO₂. Warrior Run began operations in 2000, and produces 180 MW of electricity along with steam for the CO₂ production unit. The plant captures about 10% of its CO₂ emissions, which are removed post-combustion via a slipstream (IEAGHG RD&D Database, 2013). Shady Point operates in a similar manner, except on a larger scale. The plant produces 320 MW, and has been operating since 1991. Shady Point extracts about 66,000 metric tons CO₂/day from the flue gas, which is purified to food grade levels in the CO₂ processing plant. The captured CO₂ from the Shady Point and Warrior Run plants is purified and used in food-processing and other industrial applications like fire extinguishers (NETL, *What Carbon Capture Technologies are in Use Today*).

3. Fluor Corp. – Bellingham

The Bellingham, Massachusetts CCS project, which incorporated the Fluor Ecomaine process described in section I, ran from 1991 to 2005 (Global CCS Institute, 2013). The project was a 40 MW slipstream of the 320 MW plant, capturing over 90% of CO₂ emissions totaling 100,000 metric tons of CO₂/day. This plant is unique in that it was an NGCC incorporating CCS into its operations. The CO₂ was sold for use in the beverage industry, as opposed to geologic sequestration (Bernton, 2014).

4. Petra Nova – W. A. Parish

The W.A. Parish CCS project near Houston, Texas will be the world's largest post-combustion CCS retrofit once it begins operation in 2017. The plant is a joint venture between NRG and JX Nippon Oil & Gas Exploration. Captured CO₂ will be used for EOR in the Gulf Coast region. The unit will collect 90% of the emitted CO₂ from a 240 MW slipstream of the 610 MW facility, for a total of 1.4 million metric tons CO₂/year. The CO₂ capture technology is provided by Kansai Mitsubishi, which has had CO₂ capture technology in commercial use since 1999, and currently is operating at 11 facilities across the globe (NRG Energy Inc., 2015). The plant will utilize a high-performance solvent, which was tested at a pilot-scale project at the Alabama

Power Barry plant, which is described below. The project began as a 60 MW slipstream demonstration and received DOE Clean Coal Power Initiative funding on that basis, however, the project was later expanded to the 240 MW slipstream due to the need to capture larger volumes of CO₂ for EOR operations.

5. SaskPower – Boundary Dam Unit #3

The Boundary Dam CCS project is the first commercial-scale post-combustion CCS plant in the world. Located in Saskatchewan, Canada, the Boundary Dam project incorporates EOR and Geological Sequestration into their operations, which began in October of 2014. Although initially only capturing 75% of CO₂, currently the unit produces 110 MW net (139 MW gross) of electricity, with 90% CO₂ capture totaling 1 million metric tons CO₂/year at a purity of over 99.999% (Monea, 2014). The plant uses a Shell Cansolv amine-based solvent to capture CO₂, which comes from local Saskatchewan lignite coal. In order to mitigate the cost of the retrofit, SaskPower sells the CO₂ to an oil drilling company for use in EOR and eventual sequestration, and to other industries for commercial use. The balance of unsaleable CO₂ is sequestered. The plant also sells sulphuric acid and fly ash for added revenue (Hussain, 2014). CO₂ that is not used in EOR is immediately stored in deep brine-filled sandstone formations. Additionally, initial indications are that the generation side is producing more power than estimated and that the energy penalty (parasitic load) is much lower than expected (Monea, 2015).

6. Searles Valley Minerals – Trona Soda Ash Plant

The Searles Valley Minerals soda ash plant in Trona, Ca, is the longest running carbon capture project in the U.S. The plant has been capturing CO₂ via post-combustion amine scrubbing since 1978. This CO₂ comes from the flue gas from a coal-fired power boiler generating steam and electricity for onsite use. The CO₂ is used to for carbonation reactions to produce soda ash. Since its inception, the soda ash plant has collected roughly 270,000 metric tons of CO₂ per year (EPA, 2014).

B. Pre-combustion

Table 3 contains 11 facilities that are in various stages of pre-combustion CO₂ capture projects, including nine EGUs, a fertilizer manufacturing plant, and a coal gasification facility. Each project is briefly summarized in the following subsections.

Table 3. Pre-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
2Co Energy - Don Valley Power Project	International	South Yorkshire, United Kingdom	EGU	920 MW (Gross), 650 MW (Net)	Full (>90%) CCS	2018/2019 (Planning Phase)	5,000,000	Pipeline	GS	The North Sea
CVR Energy/Chaparral Energy - Coffeyville Fertilizer Plant	Domestic	Coffeyville, Kansas	Fertilizer Plant	Not EGU		2013	1,000,000	Pipeline	EOR	112 km away
Dakota Gasification - Great Plains Synfuels Plant	Domestic	Beulah, North Dakota	Coal Gasification Plant	Coal Gasifier	Partial (50%)	1984 (began operation) 2000 (began CCS)	3,000,000	Pipeline	EOR	Weyburn EOR, 200 miles away
ELCOGAS, S.A. - Puertollano	International	Puertollano, Spain	EGU	IGCC (14 MW Slipstream)	Full (>90%) CCS	2010	365,000	Not transported	Hydrogen production	Spain
Emirates Steel Industries - Abu Dhabi	International	Abu Dhabi, United Arab Emirates	EGU	IGCC (~228 MW)	Full (>90%) CCS	2016 (under construction)	800,000	Pipeline	EOR	Rumaitha, 50 km away
Huaneng - GreenGen IGCC Project	International	Tianjin City, Bohai Rim, China	EGU	IGCC (400 MW)	Partial (>80%)	2020 (currently testing pilot)	2,000,000	Pipeline	EOR	51-100 km from the plant
Southern Company - Kemper County	Domestic	De Kalb, Mississippi	EGU	IGCC power plant (582 MW)	Partial (65%)	2016 (construction completed, currently testing)	3,500,000	Pipeline	EOR	60 miles away
Southern Company - Barry Plant	Domestic	Mobile, Alabama	EGU	Coal-fired power plant (25 MW slipstream)		June 2011 (capture) 2012 (storage)	150,000	Pipeline	GS	Citronelle oil field

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
Summit Power - Caledonia	International	Caledonia, Scotland, the United Kingdom	EGU	IGCC (570 MW)	Full (>90%) CCS	2022 (under construction)	3,800,000	Pipeline	GS	North Sea
Summit Power - Texas Clean Energy Project (TCEP)	Domestic	Odessa, Texas	EGU	IGCC (400 MW)	Full (>90%) CCS	2019	3,000,000	Pipeline	EOR	Permian Basin
Vattenfall/Nuon - Willem-Alexander Power Plant	International	Buggenum, the Netherlands	EGU	IGCC (20 MW Slipstream)	Full (>90%) CCS	2011	Not provided	Not transported	Returned to the flue stream after compressed	Netherlands

1. CVR Energy/Chaparral Energy - Coffeyville Fertilizer Plant

Chaparral Energy and Coffey Resources Nitrogen Fertilizers, a subsidiary of CVR Energy, have joined to capture and sequester roughly 1 million metric tons CO₂/year using pre-combustion technology. Chaparral manages the compression, dehydration, and transportation facilities, while CVR owns the carbon and carbon capture sources. This retrofit, completed in 2013, allows the partnership to sell CO₂ for use in EOR operations 112 km (70 miles) away (MIT, *Coffeyville Fact Sheet*, 2015). The plant utilizes absorption physical solvent-based process using Selexol for CO₂ separation. Similar to an IGCC, the plant gasifies petroleum coke to create a hydrogen-rich syngas from which the CO₂ is removed. The syngas is used to synthesize ammonia and urea ammonium nitrate fertilizers instead of being used for energy production (Chaparral Energy, 2015).

2. Dakota Gasification – Great Plains Synfuels Plant

Located in Beulah, ND, the Great Plains Synfuels Plant began operations in 1984 and later added CCS operations in the year 2000. The plant consumes roughly 18,000 tons of North Dakota lignite coal each day and captures about 3 million metric tons of CO₂ per year, which is the most CO₂ captured from conversion at any facility of the world (Dakota Gasification Company, *Great Plains Synfuels Plant*, 2015). Although not an EGU, the processes at a coal gasification plant are very similar to those at an IGCC. Dakota Gasification uses a Rectisol® system to capture CO₂ before the gasified coal is converted into synthetic natural gas (i.e., methane) via a methanation process (EPA, 2014). The CO₂ captured at the plant is sold to drilling companies for EOR and permanent sequestration in Saskatchewan, Canada as part of the Weyburn CO₂ Monitoring and Storage project, which is overseen by the International Energy Agency (IEA). The plant exports about 8,000 metric tons CO₂/day, which is about 50% of the CO₂ generated at the facility. As of December 31st, 2012, the facility had captured more than 24.5 million metric tons of CO₂, demonstrating how CCS can be used long term to reduce emissions (EPA, 2014).

3. ELCOGAS, S.A. – Puertollano

Another pilot-scale project, located at the ELCOGAS Puertollano plant in Spain, was one of the first pre-combustion IGCC CCS pilot plants in the world when it began operations in 2008. The plant uses a slip stream to test a small scale (14 MW) IGCC unit. The plant captured its first metric ton of CO₂ by 2010, and has since captured over 1,000 metric tons of CO₂. The project has also produced over 6 metric tons of H₂, as part of the project's stated goal to "obtain economic data enough to scale [the project] to the full Puertollano IGCC capacity in synthetic gas production." The Puertollano plant is part of a larger, Spanish national initiative to investigate advanced CCS technologies, including geological sequestration and oxy-fuel combustion (ELCOGAS, 2014).

4. Emirates Steel Industries – Abu Dhabi

The United Arab Emirates' first CCS project is an ambitious 800,000 metric tons CO₂/year facility operating adjacent to a steel mill in Abu Dhabi. Set to begin operations in 2016, this facility will process a 90% pure CO₂ stream from the steel plant before piping it to an oil field for EOR 50 kilometers away (Masdar, 2015). The Abu Dhabi Future Energy Company and the Abu Dhabi National Oil Company decided to continue with the project after completing a 2 year pilot plant study which ended in 2011 (Evans, 2008). The plant is expected to produce around 225 MW per year (Carvalho, 2011).

5. Huaneng – GreenGen IGCC Project

Scheduled to begin operations in 2020, Huaneng's GreenGen IGCC project is poised to be the largest EGU CCS project in Southeast Asia. The plant aims to capture 2 million metric tons CO₂/year, which will come from sub-bituminous coal coming primarily from China. The plant will provide 400 MW of electricity at this new plant, the largest of its kind in China and one of the largest in the world. However, first it will operate as a 250 MW IGCC while CO₂ capture technology is tested and developed. The facility will operate as a pre-combustion CCS plant, utilizing an amine chemical solvent-based process. (Global CCS Institute, 2011)

6. Southern Company/Mississippi Power – Kemper County

The Kemper County IGCC CCS project completed construction in late 2013 and is currently in the "startup and testing" phase, with plans to begin commercial operation in 2016. This facility, located in Kemper County, Mississippi, will provide 582 MW of lignite coal-based power while collecting 3.5 million metric tons CO₂/year. Kemper County uses Pre-combustion IGCC technology, with unique CCS technology designed by KBR to provide 65% capture. Additionally, KRG designed (TRIGTM) gasification technology to more efficiently convert lignite coal into syngas for combustion. The TRIGTM is "an advanced pressurized circulating fluidized bed gasifier that operates at moderate temperatures (1,500-1950°F)" (Ariypadi, 2008). The TRIGTM can utilize both oxy-fuel and ambient air as combustion sources to mix with the lignite coal. The plant also utilizes SelexolTM, a solvent that has also been used extensively for acid gas removal, including CO₂, for decades (Mississippi Power Company, 2009).

7. Southern Company/Mitsubishi Heavy Industries (MHI) – Barry Plant

The Southern Company partnered with MHI to create a pilot-scale CCS project at the Plant Barry Power station in Mobile, Alabama. The plant uses a 25 MW slip stream out of their 160 MW plant to capture 150,000 metric tons of CO₂/year. The plant uses an MHI amine based process called KM-CDR, and incorporates MHIA's KS-1 solvent. The plant has successfully captured CO₂ since June 2011, and began sequestering it in an underground saline formation in August, 2012. The plant was initially selected to be scaled up to a much larger size (100,000 metric tons of CO₂ capture/year) however Southern Company decided to opt out of the program in 2010 (MIT, *Plant Barry Fact Sheet*, 2015).

8. Summit Power – Caledonia

The Caledonia plant, in Scotland, the United Kingdom, is a large scale pre-combustion IGCC CSS project developed by Summit Power. The plant will produce 570 MW (net) from gasified bituminous coal, and will collect 3.8 million metric tons CO₂/year, or 90% of the total CO₂. This CO₂ is sent via pipeline to a saline formation in the North Sea for geologic sequestration (Summit Carbon Capture, 2015). The plant is scheduled to open in 2022, however it was granted funding from the UK and Scottish governments in March, 2015 to help conduct an industrial research and feasibility study to design, site, finance, and build the Caledonia Plant. The results of this study will be "shared across industry and academia, increasing understanding of how to develop and deploy CCS at commercial scale." (UK Dept. of Energy and Climate Change, 2015)

9. Summit Power - Texas Clean Energy Project (TCEP)

The TCEP will be a 400 MW IGCC facility located near Odessa, Texas. The plant will capture 90% of its CO₂, which will be around 3 million metric tons/year. The plant will sell the CO₂ for use in EOR, and will also sell urea, sulfuric acid, argon, and inert slag for use in various chemical processes (Gureghian, 2010). The plant plans to begin construction in 2015, and will utilize the Linde Rectisol® gas cleanup process to capture CO₂, the same process used at the Dakota Gasification plant. TCEP plans to begin construction in 2015 (Paul, 2015; MIT, *TCEP Fact Sheet*, 2015), and hopes to begin operations by 2019. Besides CO₂ capture, the plant will capture 99% of Sulphur dioxide, 90% of Nitrogen Oxide, and 99% of mercury.

10. Vattenfall/Nuon – Willem-Alexander Power Plant

The William-Alexander Power Plant, located in Buggenum, the Netherlands, is a coal-and-biomass-fired EGU that provides 253 MW of electricity. In 2011, the plant opened a pilot-scale CCS project testing IGCC technology with 90% CO₂ capture from pre-combustion technology. The plant used a slip stream of CO₂ equivalent to the amount produced by 20 MW of power, and then captured, compressed, and returned the CO₂ to the main stream instead of sequestering it. This process helped researchers determine feasibility and practicability of CCS for use in potential scale-ups to industrial size EGUs in the future. Due to the economic recession in the European Union, the project was discontinued in 2014, however valuable lessons were learned about CCS during the three years of operation (MIT, *Buggenum Fact Sheet*, 2015).

11. 2Co Energy - Don Valley Power Project

The Don Valley Power Project is the most ambitious pre-combustion CCS project to date. 2Co energy will produce 920 MW gross (650 MW net) of power in South Yorkshire, the United Kingdom. The plant will capture over 90% of emissions, totaling some 5 million metric tons of CO₂/year, which will be sequestered in the North Sea (2Co Energy, *Don Valley CCS Project*).

C. Oxy-combustion

Table 4 contains four EGU facilities that are implementing or planning oxy-fuel combustion CO₂ capture projects. Each project is briefly summarized in the following subsections.

Table 4. Oxy-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
Capture Power Ltd. - White Rose	International	North Yorkshire, United Kingdom	EGU	Coal-fired power plant (448 MW)	Full (>90%) CCS	planning/permitting phase	2,000,000	Pipeline	GS	The North Sea
CS Energy - Callide A Station	International	Biloela, Queensland, Australia	EGU	Coal-fired power plant (30 MW)	Full (>90%) CCS	2012	220,000(does not continuously run, captures 75 mt/day when operating)	On Road	GS	Victoria, Australia
FutureGen 2.0 Alliance	Domestic	Meredosia, Illinois	EGU	168 MW	Full (>90%) CCS	2017 (under construction)	1,100,000	Pipeline	GS	Various Locations
Total - Lacq	International	Lacq, France	EGU	Heavy oil-fired power plant (30 MW unit of larger facility)	Full (>90%) CCS of the unit's emissions, 15% of the plant's emissions	January, 2010	75,000	Pipeline	GS and natural gas recovery	Rousse, France (27 km away)

1. Capture Power Limited - White Rose CCS project

Capture Power Limited, which is a consortium of Alstom, BOC, and Drax Power, is currently planning an industrial scale oxy-fuel CCS facility in North Yorkshire, the United Kingdom. The plant will produce 448 MW of electricity from coal, capturing over 90% of the emitted CO₂, totaling 2 Million metric tons CO₂/year. The CO₂ will be piped to the North Sea, where it will be geologically sequestered (White Rose, 2015).

2. CS Energy – Callide A Station

Located in Queensland, Australia, the Callide A station is the first industrial-scale pilot plant in the country. The 30 MW coal-fired unit, part of the larger Callide plant, captures over 90% of its CO₂ emissions when running the capture technology, which is not done continuously because it's a pilot plant. The plant captures roughly 220,000 metric tons of CO₂/year. This CO₂ is pressurized and sent via trucks to Victoria, Australia, where it is sequestered underground. This pilot plant began operations in 2012. This project shows how old units (Callide A first began operations in 1965) can be retrofitted with CCS technology to cost-effectively reduce emissions (Callide, 2015).

3. FutureGen 2.0 Alliance

The FutureGen 2.0 project is a combined effort from industry and government to produce a full scale oxy-fuel combustion CCS plant in the United States. Located in Meredosia, Illinois, the 168 MW EGU will implement full CCS using purified oxygen as fuel, allowing the plant to capture over 1.1 Million metric tons of CO₂/year (FutureGen 2.0, *About FutureGen 2.0*). CO₂ captured from the plant will be sent via pipeline to various locations for use in EOR or simple geologic sequestration. Completion of the project is scheduled for 2017, making FutureGen the first full CCS plant using oxy-fuel combustion in the US (FutureGen 2.0, *About FutureGen 2.0*). The EPA has issued Class VI deepwell construction permits for the sequestration phase.

4. Total – Lacq Plant

Total, in combination with Air Liquide, the French Petroleum Institute, the French Bureau of Geological and Mining Research, and Alstom, worked to construct an oxy-fuel pilot plant at the Lacq facility in southern France. The 30 MW project runs on heavy oil, and captures over 90% of the unit's emissions, about 15% of the plant's total emissions. The Lacq oxfuel project began operations in January 2010, and has captured 75,000 metric tons of CO₂/year each year since (Total, *How CCS at the Lacq Pilot Works*). This CO₂ is transported via pipeline to Rouse, France, where it is used for natural gas recovery and geologic sequestration.

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