

Technical Overview of Carbon Dioxide Capture Technologies for Coal-Fired Power Plants

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SUMMARY

Concerns about global climate change have prompted interest in capturing and sequestering CO₂ generated at coal-fired power plants. This document provides a technical introduction to methods of capturing CO₂, which involves separating the CO₂ from the other constituents in the flue gas. The methods discussed in this paper are post-combustion capture, oxygen-fired combustion, and pre-combustion capture:

- Post-combustion capture of CO₂ from flue gases uses proven chemical absorption methods that can be installed at existing power plants, but the impact on O&M and capital costs would be significant. For a coal-fired plant, the size and capital cost of the absorber would be comparable to an existing SO₂ scrubber, but approximately 1/4 to 1/3 of the total steam produced by the plant would be consumed in the chemical absorbers, thus reducing the plant capacity by approximately 25% to 35%. This option allows continued use of existing coal-fired power plants and would likely be the first option implemented. Although significant technical challenges exist, developing this option is primarily an issue of technology transfer since the methods are currently in use on a smaller scale in other applications.
- Oxygen-fired combustion, which produces a 90% CO₂ exhaust stream, provides some multi-pollutant control, but the technology is less mature and the O&M and capital costs would be comparable to post-combustion capture. Specifically, the oxygen separation plant would consume about 23% to 37% of the total plant output and cost about the same as the absorber. This option is most appropriate for new plant projects and would become attractive only when new plant development becomes more desirable than retrofitting existing coal-fired plants. Significant technical challenges will need to be addressed before it can be implemented.
- Pre-combustion capture, which involves capturing CO₂ from syngas generated in a coal gasifier, is potentially less expensive than post-combustion capture. It is considered a promising long-term option but the required technology is still being developed. Power plants that use pre-combustion capture are also attractive because they are based on a combined cycle (Brayton and Rankine) design, which is inherently more efficient than the Rankine-only cycle that traditional coal plants use. In addition, since hydrogen production is a potential option, pre-combustion capture is also compatible with a hydrogen economy. This option is also only appropriate for new plant projects. Significant technical challenges will need to be addressed before it can be implemented.

The main conclusion of the paper is that the technical challenges of CO₂ capture appear to be similar in scope and complexity to the challenges the power industry has already overcome in successfully removing SO₂ and NO_x from the flue gas, but the economic impacts of CO₂ capture

are much greater largely because of the significant plant capacity penalty of approximately 25% to 33%. Further, because of the large quantity of CO₂ captured (e.g., approximately 3,000,000 lb/hr for a 1000 MW power plant), on-site storage of the captured CO₂ is not feasible and therefore a means is required for transporting the captured CO₂ off-site at the same rate at which it is captured.

INTRODUCTION

Purpose

This document provides an introduction to the technologies for capturing CO₂. The intended audience is technical professionals familiar with the power industry. A basic description of the underlying science and the hardware used to implement it is provided. Advantages, disadvantages, technical maturity, and potential for improvement of each option are discussed.

Sequestration of the captured CO₂, which involves short-term storage, transportation, and long-term storage, is outside the scope of this paper. A separate MPR paper: *Technical Overview of Carbon Dioxide Sequestration Technologies* (Reference 1) addresses the topic of sequestration.

Background

Many scientists have concluded that the observed global climate change is due to the greenhouse gas effect, in which man-made greenhouse gases alter the amount of thermal energy stored in the Earth's atmosphere, thereby increasing atmospheric temperatures. The greenhouse gas produced in the most significant quantities is carbon dioxide (CO₂). The primary source of man-made CO₂ is combustion of fossil fuels. Stabilizing the concentration of atmospheric CO₂ will likely require a variety of actions including a reduction in CO₂ emissions.

If CO₂ emissions are regulated in the future, the power industry is likely to be the prime target. Table 1 shows U.S. annual CO₂ emissions by sector in 2003. The power sector accounts for approximately one third of the total. It is easier to sequester CO₂ from a stationary rather than a mobile source (i.e., the transportation sector). In addition, many sources in the industrial and commercial sectors can relocate overseas if regulations become too prohibitive, but the power industry cannot. There is a particularly strong interest in capturing CO₂ from coal-fired plants because coal plants account for approximately 50% of power generation in the U.S. and because coal is more carbon intensive than the other commonly used fossil-fuels. That is, they emit the most carbon per unit of electrical energy generated. Oil-fired power plants are approximately two thirds as carbon intensive as coal-fired plants and natural gas fired combined cycle plants are approximately half as carbon intensive.

Approaches to CO₂ capture can be divided into three categories: post-combustion capture, oxygen-fired combustion, and pre-combustion capture. Within some of these categories there are different technologies that can be used. A description of each category and the different technologies follows.

Table 1. Sources of CO₂ Emissions in the U.S. in 2003 (Reference 2)

Sector	CO₂ Emissions (expressed in millions of metric tons of carbon)	Percent of Total (%)
Power	2285	28
Transportation	1872	23
Industrial	1664	21
Commercial	1028	13
Residential	1225	15
Total	8074	---

POST-COMBUSTION CAPTURE

Post-combustion capture involves capture of CO₂ from flue gases post-combustion. This method requires separating the CO₂ from other flue gases because sequestration of combustion gases is not feasible due in part to the cost of gas compression and storage. Post-combustion capture offers a significant design challenge due to the relatively low partial pressure of the carbon dioxide in the flue gas. In addition, the relatively high temperature of flue gases offers an additional design challenge. There are several technologies that can be employed within this category. Chemical absorption, gas separation membranes, and low temperature distillation are the technologies discussed.

A schematic diagram and approximate mass balance of a typical 1000 MW coal-fired power plant with post-combustion capture is shown in Figure 1. This diagram shows that for post-combustion capture, the CO₂ capture equipment would be installed downstream of any existing pollution control equipment. Figure 1 shows a supply of low-pressure steam to a post-combustion CO₂ removal process using chemical absorption. Other technologies would not require steam. The steam would normally be extracted from the steam cycle, decreasing the net plant output. After compression the CO₂ stream shown at the bottom right of the figure would be available for sequestration.

The mass balance shown in Figure 1 illustrates the following:

- The CO₂ emissions are three times the coal flow.
- The CO₂ emissions are approximately 30% of the stack gas flow.

Chemical Absorption

Chemical absorption has been the most widely used method of commercial CO₂ capture for over 60 years (Reference 3). Existing commercial applications include enhanced oil recovery which involves increasing oil production rates by injecting CO₂ into oil wells. Chemical absorption is a chemical reaction that forms a loosely bonded intermediate compound. For the CO₂ capture application a chemical solvent is exposed to the flue gas where it reacts chemically with CO₂

separating it from the other gases. The intermediate compound is then isolated and heated causing it to break down into separate streams of CO₂ and solvent. The solvent most often used is monoethanolamine (MEA).

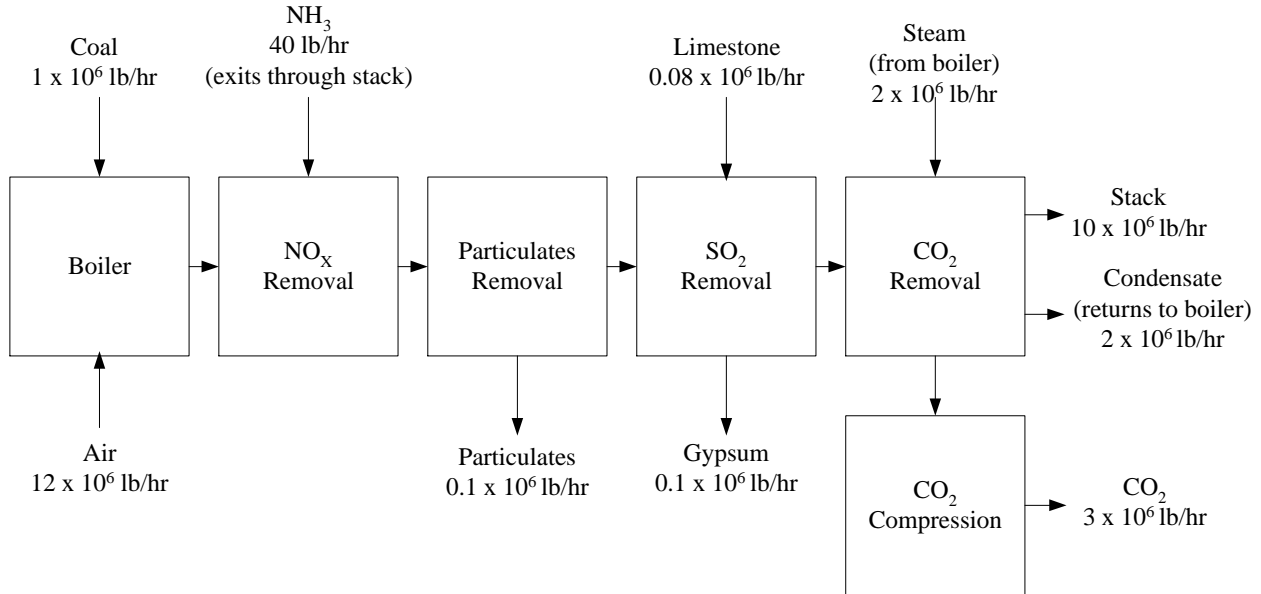


Figure 1. Mass Balance for a Typical 1000 MW Power Plant with Post-Combustion CO₂ Capture

A simplified schematic showing a typical flow diagram for the chemical absorption process is shown in Figure 2. The major components include an absorber, regenerator (stripper), solvent storage tank, heat exchanger, CO₂ condenser, and booster pump. The entire flue gas stream is diverted into the process at the left side of the figure. The chemical solvent and CO₂ are exposed to one another in the absorber where they react chemically to form the loosely bonded intermediate compound. This compound, in liquid form, is then isolated by transferring it to the regenerator (also called stripper) where it is heated causing it to break down into separate streams of CO₂ and solvent. The CO₂ is condensed in the condenser and sent for further processing such as dehydration and compression before it is ready for storage or commercial use. The solvent stream produced in the regenerator is recycled back to the absorber and the process repeats. A storage tank is installed in the solvent return line to allow for constant CO₂ removal under varying solvent recycling rates. A booster pump installed in the solvent return line provides the pressure gradient required to transport the solvent. The heat exchanger captures waste heat by transferring heat from the relatively hot fluid returning from the regenerator to the relatively cool fluid flowing to the regenerator.

The chemical absorption process uses pressure vessels, storage tanks, pumps, and heat exchangers similar to those of many other industrial processes. The absorber module is a gas/liquid contactor located within a carbon steel vessel or duct. This component is similar to the wet scrubber modules retrofitted onto many coal-fired power plants to reduce sulfur

emissions. During operation the absorber module pressure and temperature are approximately equal to those of the exhaust entering the module. Unlike the wet scrubber, there is no significant waste product generated in the absorber module.

The chemical absorption process produces a relatively pure carbon dioxide stream and the technology is well-developed and commercially available today. The disadvantage of the process is that it would consume a significant amount of the energy produced by the power plant. A typical "energy penalty", which is defined as the percentage of the net power output consumed for the chemical absorption process installed on a conventional coal-fired power plant is between 25%-37% (Reference 3). The energy penalty for a gas-fired power plant is less than for a coal plant since gas contains less carbon per unit energy than coal does. A typical energy penalty for a gas-fired power plant is between 15%-24% (Reference 3). The energy penalty introduces a significant operating cost for the chemical absorption process.

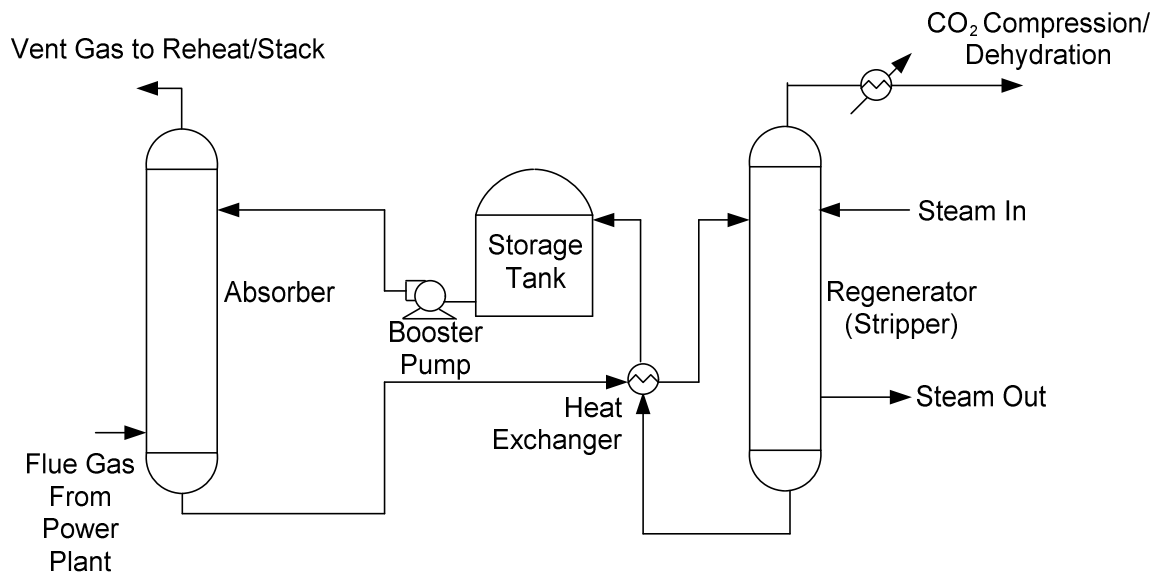


Figure 2. Simplified Chemical Absorption Process Diagram (adopted from Reference 3)

Another shortcoming of the chemical absorption process is that it has a relatively high capital cost. The large size of the major components significantly influences the capital cost. The footprint of a coal-fired power plant is expected to increase approximately 60% with the addition of chemical absorption-based CO₂ capture¹.

The chemical absorption process is mature and has been used for many years to produce CO₂ from flue gas streams on a relatively small scale. The recovered CO₂ is used for enhanced oil recovery, production of soda ash, and various food grade applications. Note that this process has

¹ Based on adding CO₂ capture to a coal-fired power plant that already employs particulate and sulfur recovery. The approximate footprint for the base plant is 636 ft²/MW and the approximate footprint for the base plant with chemical absorption-based CO₂ capture is 1009 ft²/MW (Reference 4).

been optimized for these existing applications, which all involve an economic benefit of producing the CO₂. That economic benefit does not exist for power plant CO₂ capture and therefore further optimization of the process for power plants is being investigated to reduce the operating and capital costs.

Other potential issues that would affect the cost of implementing chemical absorption systems include the following:

- Work to date has used chemical absorption on a small scale. Issues involved with scaling up the existing technology will need to be addressed.
- SO₂ contained in exhaust gas will degrade the amine solution. Effective means of addressing this issue in large-scale installations that do not have effective SO₂ scrubbers will be required.
- Degradation of the amine solution due to the presence of oxygen in the flue gas also needs to be investigated.
- Reliable operation of packed towers used in chemical absorption systems will need to be demonstrated.

In 2000 the National Energy Technology Laboratory estimated that post-combustion capture using chemical absorption would result in a 70% increase in cost of electricity. Improved sorbents may reduce the energy penalty and capital cost of the chemical absorption process. To reduce the energy penalty the focus would be to reduce the high regeneration energy requirement. Researchers in Japan have developed an advanced sorbent that requires less steam for regeneration and involves regeneration at a lower pressure. Although still in a developmental phase, it has been estimated that the energy penalty would decrease to 15% and 10% to 11% for coal-fired and gas-fired applications respectively (Reference 5). In addition, capital costs may decrease due to technological advancements that allow for a reduction in size of the absorber module and other major components. This would be achieved by optimizing the design of the absorber module to make it more space efficient. NETL has made a goal of reducing the increase in cost of electricity associated with this process to 20%.

Gas Separation Membranes

Gas separation membranes (or simply membranes) can capture CO₂ by separating it from the other exhaust gases. There are several different mechanisms of separation including solution-diffusion and molecular sieving. The solution-diffusion mechanism involves the gas dissolving into the surface of the membrane and then diffusing through the membrane by mass transfer. Molecular sieving involves physical separation of smaller molecules from larger ones by means of a very fine mesh.

Membranes are typically categorized by material type. Polymeric and inorganic are two common types. Polymeric membranes transfer gases by the solution-diffusion mechanism. They are effective, inexpensive, and can achieve a large ratio of membrane surface area to separation module volume (i.e., lower capital cost). However, they are susceptible to degradation and their performance is low for certain gas flow characteristics. There appears to be a practical limit to the development of polymeric membranes for separation of CO₂.

Inorganic membranes utilize many separation mechanisms, which allows for some optimization of the separation process. In some areas inorganic membranes outperform polymeric membranes, but inorganic membranes are much more expensive and the ratio of membrane surface area to separation module volume is much worse than for polymeric membranes. The potential for inorganic membranes to be appropriate for CO₂ capture is considered more promising than for polymeric membranes.

It may be possible to use gas separation membranes to capture CO₂ from synthesis gas produced during the gasification process. This application is discussed in more detail under Pre-Combustion Capture.

Overall, gas separation membranes are in an early stage of development. It has not yet been demonstrated that they can be practically applied to large-scale carbon capture applications.

Low Temperature Distillation

In the low temperature distillation process a low-boiling-temperature liquid such as nitrogen is evaporated and then condensed and separated. To use this process to capture CO₂ requires pressures above 75 psia and temperatures above -70 °F. Low temperature distillation is used commercially for purification of CO₂ from high purity sources (>90% CO₂). The process is most cost-effective when applied to feed gases that are at high-pressure and when the distillation products are also required at high-pressure. In addition, it is only applicable when the boiling points of the feed gas constituents are sufficiently spaced.

Low temperature distillation is not considered a promising technology for capture of CO₂ because the conditions required for this method to work are not typical for a power plant.

OXYGEN-FIRED COMBUSTION

This option produces a high concentration of CO₂ in the exhaust gas stream by generating less non-CO₂ gas during combustion. This is accomplished by burning fuel with pure oxygen instead of air. Oxygen-fired combustion is simpler and less chemically intensive than post-combustion capture, but is less mature and similarly expensive. This option provides some multi-pollutant control and allows for smaller gas handling equipment, but requires an energy penalty of 23-37% and high capital cost. Oxygen-fired combustion is not currently economically viable and is currently under development. Pilot scale demonstrations have been conducted.

Because oxygen is used instead of air, the nitrogen component of air and its combustion products are eliminated from the exhaust gas stream. Nitrogen typically makes up a significant portion of the exhaust gas so eliminating it significantly increases the concentration of CO₂, thereby providing CO₂ capture without additional processing.

Burning with oxygen results in combustion temperatures that are too high for furnace materials so a portion of the exhaust gas (mostly CO₂) is recycled to the furnace to reduce the combustion temperature to within allowable limits. For this reason oxygen-fired combustion is sometimes referred to as CO₂ recycling. The oxygen would be generated on-site. Near-term, oxygen would be generated using mature cryogenic methods. Long-term, a process based on ion transport

membranes may be more attractive, however that technology is not expected to be available until approximately 2010.

A schematic diagram of an oxygen-fired combustion system is shown in Figure 3. Particulates and sulfur compounds are first removed from the exhaust stream using standard equipment. After SO₂ removal the exhaust gas stream is approximately 90% CO₂ by volume on a dry basis. After compression this stream would be available for sequestration. Other examples of oxygen-fired combustion systems include processes based on circulating fluidized bed (CFB) technology (Reference 6) and chemical looping processes (References 6 and 7).

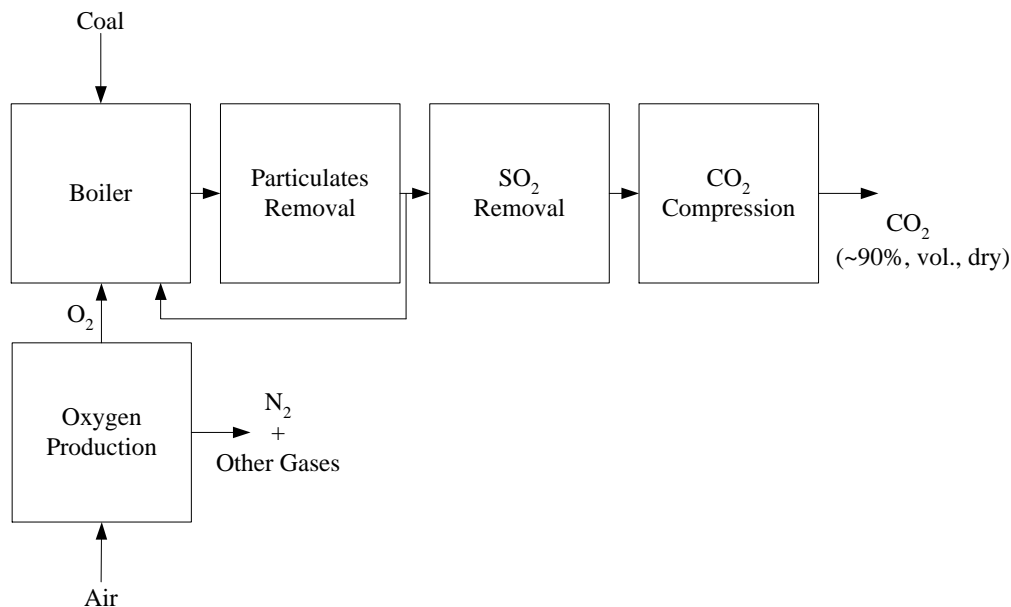


Figure 3. Power Plant with Oxygen-Fired Combustion

Exhaust gases, which are mostly CO₂, are recycled back into the boiler for reasons discussed above. This recycling concept is similar to gas recirculation systems in existing boilers and would not be a significant technical challenge. The oxygen production unit separates air into streams of oxygen and nitrogen mixed with other gases. The nitrogen and other gases are vented to atmosphere and the oxygen is sent to the furnace.

The primary advantages of oxygen-fired combustion are it is not chemically intensive and it retains the coal-fired boiler for which there is extensive operating experience. In addition, NO_x normally formed from nitrogen in air is absent and boiler size can be reduced while maintaining the same flow velocities since the volume flow rate of exhaust gas is decreased with the replacement of air with oxygen. The size of other gas handling equipment can also be reduced including equipment for removing sulfur compounds and particulates.

The primary disadvantage of oxygen-fired combustion is the energy penalty of 23-37% resulting primarily from the production of oxygen which is approximately the same as the penalty for the

chemical absorption process. Another disadvantage is the high capital cost which has been estimated to be approximately \$2040/kW (Reference 8). Boiler corrosion problems associated with SO₂ in the exhaust stream are worsened due to the increased concentration of SO₂ that results from the CO₂ recycling. Sulfur is introduced by the fuel and is therefore not reduced by switching to oxygen-fired combustion. The large size of the major components significantly influences the capital cost. The footprint of a coal-fired power plant is expected to increase by approximately 150% with the addition of oxygen-fired combustion for CO₂ capture².

Oxygen-fired combustion for CO₂ capture is in an early stage of technological development. At \$2040/kW the process is not economically viable. However for a true comparison to post-combustion capture the reduced cost of CO₂ processing due to simultaneous NO_x reduction should be considered. Near-term technology involves cryogenic based oxygen production whereas ion separation membranes have potential for longer-term (2010) application. Some affects on the combustion process and boiler materials require further study including the following (Reference 9):

- The effect of high concentrations of SO₂, particulates, CO₂, and H₂O on burners, the boiler, superheater tubes, and the gas recycling system,
- Flame stability,
- The effect of SO₂ on final CO₂ disposal.

PRE-COMBUSTION CAPTURE

Pre-combustion capture involves removal of CO₂ from the fuel before combustion. This is accomplished by installing CO₂ capture equipment between a gasifier and combined cycle power plant. After capture, a separate stream of CO₂ and combustible gases (mostly hydrogen) is available. The combustible gases can be burned to make electricity and the CO₂ is available for sequestration.

A schematic diagram of a combined cycle power plant with pre-combustion capture is shown in Figure 4. This diagram shows the CO₂ removal equipment (and other equipment) installed between a gasifier and a combined cycle power plant. This figure also shows the relatively high level of complexity relative to the other options discussed in this paper. The gasifier, shown at the far left, has inputs of coal, oxygen, and steam. Its output is hot raw synthesis gas (often referred to as "syngas"). The syngas is eventually used as a fuel for a combined cycle power plant shown at the far right of the figure. Before reaching the power plant, the syngas is treated in a variety of different processes. The syngas is cooled to protect downstream equipment. Particulates are removed often in a wet scrubbing process, which provides further gas cooling. Hydrogen sulfide (H₂S) is removed. CO₂ is removed. Finally, the clean syngas is sent to a combined cycle power plant to produce electricity.

² Based on adding CO₂ capture to a coal-fired power plant that already employs particulate and sulfur recovery. The approximate footprint for the base plant is 636 ft²/MW and the approximate footprint for the base plant with oxygen-fired combustion for CO₂ capture is 1591 ft²/MW (Reference 4).

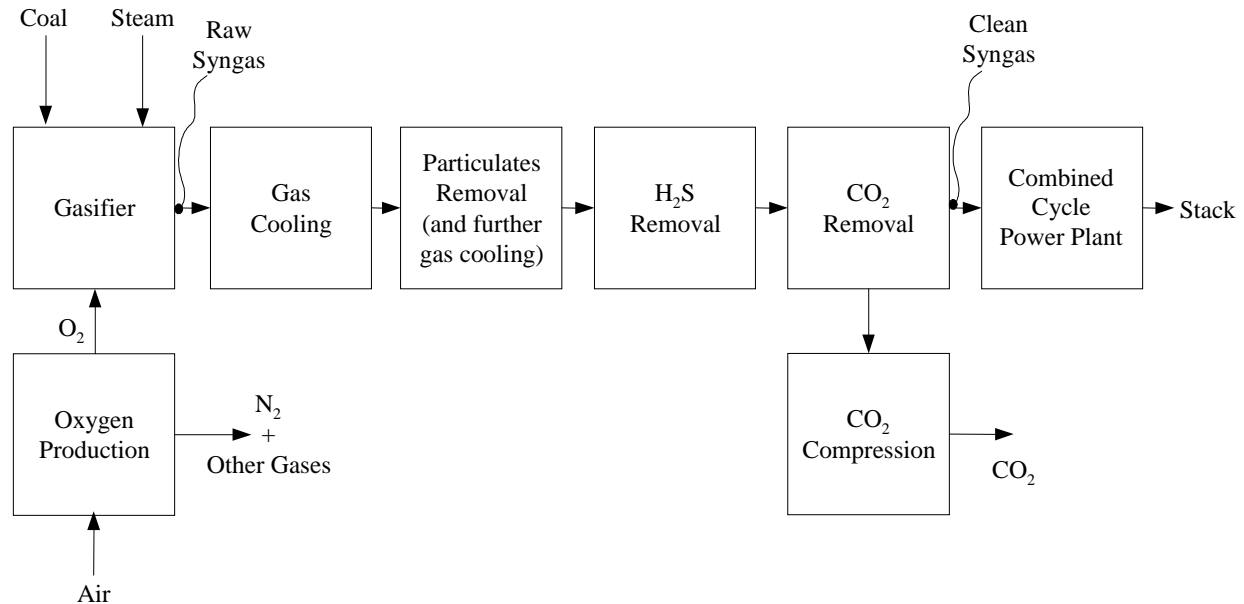


Figure 4. Power Plant with Pre-Combustion Capture

Pre-combustion capture offers a more moderate energy penalty of 10% based on gasification or steam reforming. The high partial pressure of CO₂ could allow for the use of more efficient capture technologies (i.e., physical absorption), which would further reduce the energy penalty. Pre-combustion capture also has more potential for future use. The DOE has a goal of reducing the increase in cost of electricity resulting from the use of pre-combustion capture to 10% compared to 20% for post-combustion capture.

The primary disadvantage of pre-combustion capture is that total capital costs of the generating facility are very high. Operating costs are higher than for standard plants due to the energy penalty, but they are lower than for post-combustion capture. In 2000 the DOE estimated that the increase in cost of electricity resulting from the use of pre-combustion capture would be 25%. Affordable pre-combustion capture will require significant R&D investment. Hot gas cleanup technology and improved oxygen production processes are two areas of development.

Pre-combustion capture is achieved by adding additional processing steps to coal gasification or steam reforming of natural gas. Gasification is addressed here because it is the more promising application for power production with sequestration, partly because natural gas without CO₂ capture naturally results in half the CO₂ emissions of coal.

Gasification is partial oxidation of a solid hydrocarbon fuel to produce a gaseous fuel. The most common version of this process is coal gasification in which coal is converted into syngas, a relatively clean-burning gas that contains CO₂. Syngas has several uses, one of which is fuel for power generation. For pre-combustion capture CO₂ is removed prior to combustion. There are several different types of gasifiers, which differ by operating conditions (e.g., pressure) and the method of reaction (i.e., fluidized bed, entrained-flow etc.). Figure 5 shows a schematic of an entrained-flow gasifier. With this type of gasifier, coal is entrained in a stream of steam and

oxygen and enters at the top. Partial oxidation of the coal occurs in a complex sequence of chemical reactions. The resulting syngas exits in a separate stream from the side of the gasifier. The portion of the coal that does not react (slag) exits from the bottom and is discarded. The operating pressure of gasifiers varies and there are many trade-offs involved with selecting the operating pressure. One vendor states that 430-580 psi is close to the optimal pressure (Reference 10).

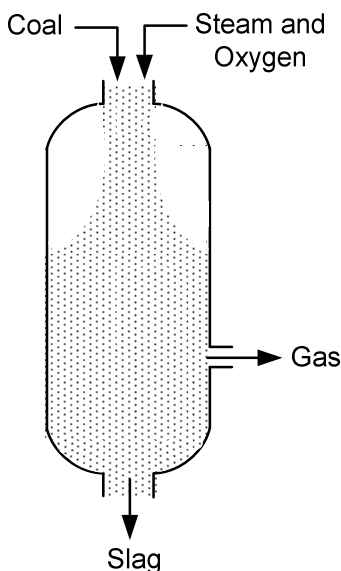


Figure 5. Entrained-Flow Gasifier (adopted from Reference 10)

When synthesis gas fuels a plant similar to a traditional combined cycle power plant the process is referred to as Integrated Gasification Combined Cycle (IGCC). There are many different possible configurations for an IGCC plant. One possible configuration is illustrated in Figure 6, which shows a simplified schematic of an IGCC power plant fitted with CO₂ capture. This is an expanded version of Figure 4. The inputs to the gasifier are coal, water, and oxygen. Oxygen is fed to the gasifier instead of air so that CO₂ partial pressures will be high enough to allow use of more energy efficient CO₂ removal processes. Steam is required because it is one of the reagents of the chemical reaction that take place inside the gasifier. The products of gasification are synthesis gas (mostly hydrogen) and carbon monoxide (CO). An additional processing step, not shown in Figure 6, is a shift reaction that reacts the CO with steam to produce CO₂ and hydrogen.

Modern gas cleanup technology requires the gas to be cooled before processing. This cooling can be achieved more efficiently using heat recovery heat exchangers that produce steam; however this adds operational complexity. Gas cooling is typically integrated into the gasifier design. Particulate removal equipment (e.g., a venturi scrubber) can also provide additional gas cooling. An alternative to extensive gas cooling is to use hot gas cleanup technology, which is still in a developmental stage.

are discussed below in greater detail. The removed CO₂ is compressed and is then ready for sequestration.

The synthesis gas is burned as fuel in the gas turbine combined cycle power plant. If the gasifier is fired with oxygen and fuel nitrogen compounds are removed during gas cleanup then the NO_x is formed exclusively in the combustion turbine, which produces relatively little NO_x.

Waste heat contained in the turbine exhaust gas is captured for steam production using heat recovery steam generation. The steam is sent to a steam turbine for additional production of electricity.

The compressor for the gas turbine also supplies compressed air to the oxygen production unit, which separates air into separate streams of oxygen and nitrogen combined with other gasses using the method described for oxygen-fired combustion. Near-term technology involves cryogenic based oxygen production whereas ion separation membranes have potential for longer-term (2010) application. The oxygen is an input to the gasifier and the nitrogen is sent to the combustion chamber to reduce NO_x emissions by decreasing combustion temperatures.

Several entrained flow gasifiers have been built and operated primarily to produce hydrogen for ammonia synthesis. One disadvantage of the IGCC power plant is that it is a complex process that requires a high degree of component integration.

Methods of Pre-Combustion CO₂ Capture

A few different processes could potentially be used to capture CO₂ in this application. The options are different than those for post-combustion capture, partly because with pre-combustion capture the CO₂ in the input gas stream is at a significantly higher partial pressure.

Physical absorption is the most mature technology that could be used. As mentioned above, this is also the process that would be used to remove sulfur products during gas cleanup. Some economy of scale can be achieved by sharing equipment between the absorption systems for sulfur removal and CO₂ removal. However, two separate gas streams are required since the sulfur products must be kept separate from the CO₂ after removal. Physical absorption occurs by mass transfer of gas molecules into a solvent. This process is governed by Henry's law, which states that the amount of absorbed gas is proportional to the partial pressure of the gas. Physical absorption is more appropriate for pre-combustion applications than for post-combustion because gas partial pressures are significantly higher. Physical absorption is a complicated capital-intensive process. The solvent used would likely be Selexol, which is currently used in industrial applications.

This technology is mature and would require relatively little engineering to use for pre-combustion capture at an IGCC power plant.

Membranes is a developmental technology that the DOE has proposed for use in the FutureGen power plant, a research initiative involving an IGCC plant with pre-combustion capture (Reference 11). Membranes for this application are still in the research and development phase. More details on membranes are provided in the section on post-combustion capture.

Hydrate-based separation is a novel concept that could potentially be used to separate CO₂ in pre-combustion applications. CO₂ hydrate is an ice-like substance that traps CO₂ molecules in a lattice of water molecules. It is stable at high pressures and low temperatures. The process would begin with hydrate formation achieved by exposing the synthesis gas containing CO₂ to water under high pressure. When the hydrate forms, the CO₂ is captured. The hydrate is then separated and disassociated, thereby releasing pure CO₂.

This technology is in the research and development phase. Nexant, Inc. is conducting research funded by the DOE to develop hydrate-based pre-combustion capture for an IGCC power plant. Their process, called the SIMTECHE CO₂ hydrate production process, is estimated by Nexant to have an energy penalty of approximately 6% to 8%. This low energy penalty would make hydrate-based separation attractive for long-term applications assuming development efforts result in a process that has sufficiently low capital costs. The DOE has stated that they consider this to be the most promising long-term CO₂ capture technology identified to date (Reference 12).

CONCLUSIONS

The following conclusions are made:

1. The technical challenges of CO₂ capture appear to be similar in scope and complexity to the challenges the power industry has already overcome in successfully removing SO₂ and NO_x from the flue gas, but the economic impacts of CO₂ capture are much greater largely because of the significant plant capacity penalty of approximately 25% to 33%.
2. Because of the large quantity of CO₂ captured (e.g., approximately 3,000,000 lb/hr for a 1000 MW power plant), on-site storage of the captured CO₂ is not feasible and therefore a means is required for transporting the captured CO₂ off-site at the same rate at which it is captured.
3. CO₂ capture is technically feasible using existing chemical absorption technology applied in a post-combustion arrangement. Significant technical challenges would need to be overcome before existing technology can be used on a large-scale, however it would primarily be a process of technology transfer.
4. Oxygen-fired combustion has the potential to be more attractive than post-combustion capture for new plant projects if improved methods of separating oxygen are developed. Significant technical challenges will need to be addressed before it can be implemented.
5. A pressurized gasifier firing oxygen in a pre-combustion arrangement is potentially the most advantageous option, since the emitted CO₂ will be at a relatively high partial pressure which greatly simplifies the CO₂ removal process. Advances in gasification technology and improved methods of separating oxygen will be required before this option can be used. Power plants that use pre-combustion capture are additionally attractive because they are based on a combined cycle (Brayton and Rankine) design,

which is inherently more efficient than the Rankine-only cycle that traditional coal plants use. Since hydrogen production is a potential option, pre-combustion capture is also compatible with a hydrogen economy.

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