Carbon Capture and Storage: Technology Status, Cost, Deployment Timing for Electric Power Generation

Summary

The U.S. enjoys significant economic and energy security benefits from the use of coal. Coal is used primarily for the production of electricity, but can also be converted to transportation fuels and substitute natural gas as well as a source of feedstock for the chemical industry. Concerns about climate change are leading to requirements to reduce greenhouse gas emissions (i.e. carbon dioxide, CO_2) from these coal based processes. In order to help meet possible new emissions requirements, effective and affordable carbon capture and storage (CCS) technologies must be developed, demonstrated and deployed. In this paper the discussion will focus on CCS technologies that will be integrated with a variety of advanced clean coal technologies used to convert coal to electricity.[1]

These innovative coal conversion technologies that provide carbon capture need to be demonstrated with storage at a commercial scale in a manner that minimizes technology and financial risks. To that end, a “step-wise” CCS demonstration and deployment approach is needed.[2] By gradually increasing levels of CO_2 capture, in a series of commercial scale demonstrations, industry will be able to transition coal-based electricity production from today’s operations to one in which CCS systems are routinely installed and operated reliably and at least cost. [3] This step-wise introduction of CCS will require significant government financial incentives and reasonable performance requirements which will enable first-of-a-kind plants outfitted with CCS to be economically practical given the increased cost and higher parasitic power requirements when CCS systems are installed. Once the initial demonstrations have proven the basic viability of CCS, demonstrations with larger volumes of CO_2 capture can be initiated. Concurrently, research and development programs to improve CCS technologies are also needed. Improved CCS technologies will over time

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[1] While not specifically addressed in this paper, coal can also be converted to liquid fuels, substitute natural gas as well as a variety of feedstocks for use in the chemical industry. The capture of CO_2 emissions from these conversion processes is easier to address because the separation of the CO_2 is part of the conversion process itself and thus does not require additional equipment to “capture” the CO_2. The discussion in this paper relative to the transport and use or storage of CO_2 is applicable to these types of facilities.

[2] Demonstration projects generally include both technology risks as well as financial risks, whereas, deployment projects will still include a high degree of financial risk but the risk of technology failure is minimal. As a result, demonstration projects tend to include redundancy in equipment as well as methods to avoid or circumvent failures in technology or portions of a process and these efforts to address technology failure add to the increased costs of demonstration projects. Also, demonstration projects can be constructed at sizes that are not optimal commercial scale, i.e. not at a scale intended to achieve “economies of scale;” but once proven these projects can be scaled up for full commercial application. Deployment projects are more likely to be constructed principally for commercial use.

[3] While it is important to seek the demonstration and deployment of CCS systems that will reliably and cost-effectively capture 85% and more of CO2 emissions, “first-of-a-kind” CCS projects can be expected to capture a significantly lower percentage as industry learns by doing. In addition, it is quite possible that cost-effective CCS technologies that capture less than 85% of the CO_2 emitted from existing coal-fired power plants can be retrofitted onto these units. Therefore, a requirement that some significant percentage of CO_2 capture is required in order to qualify for government incentives or to comply with future requirements is not advisable at this early stage of CCS technology development and use.

improve the economics of CCS integration into the Nation's coal-fired power generation fleet.

Much progress has already been made in the development of CCS technologies. The many components of CCS technology exist today having been employed in other industries. These components can be commercially deployed in small numbers in the power generation sector; however installation of today's CCS technology will be expensive. For example, if 90% or greater capture of CO_2 is required, the cost of the CO_2 capture equipment could increase the cost of electricity produced by 40% to 75% depending on the application and CCS technology used.[4] CCS will also reduce the capacity of the generating unit – due to the energy requirements to operate CCS

Finally, underground injection and storage (in saline formations) of acid gases including CO_2 has been practiced at small scale for over 20 years in Alberta, Canada, and a small number of larger scale operations on non-power applications also exist. CO_2 use in enhanced oil recovery (EOR) operations, such as the Weyburn project in Saskatchewan, Canada has been demonstrated with CO_2 from coal-based systems. However, CO_2 has yet to be captured from a coal-fueled electricity generation facility and then compressed, transported and stored into deep geologic formations.[5]

The challenge for CCS is three-fold:

- ***Integrate the many components*** needed for CCS with commercial scale electricity production systems, so that we may start "learning by doing."
- ***Accelerate research and development*** on more advanced CCS systems, especially capture research and demonstrations, to dramatically reduce its commercial cost and performance impacts.
- ***Create a regulatory framework*** for the storage portion of CCS that protects the environment while providing pragmatic rules for practical systems of CO_2 storage.

Introduction

CCS technology has been cited by most authoritative sources on climate change mitigation, including the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA), as a critical, if not the most important technology to enable society to meet stringent greenhouse gas (GHG) reduction

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[4] Currently, the cost to capture CO_2 from a gasification-based facility is less than capturing CO_2 from a combustion-based facility. However, an IGCC power plant is estimated to cost as much as 20% more than today's pulverized coal combustion system and as a result the cost of electricity from a gasification or a combustion-based system equipped with today's CO_2 capture technology is about equal. See: "Economic Assessment of Advanced Coal-Based Power Plants with CO_2 Capture," George Booras, EPRI, before the MIT Carbon Sequestration Forum IX Advancing CO_2 Capture, Cambridge, MA, September 16, 2008

[5] The use of captured CO_2 for EOR could provide an early bridge to demonstrating CCS with actual power plant operations. This paper does not address the current status of using captured CO_2 for EOR purposes.

goals.[6] The technologies to capture CO_2 and those to store CO_2 are separate, and each faces its own set of challenges. The technologies for capturing CO_2 are in various phases of commercial development, depending upon the associated electricity generation method, such as pulverized coal boilers, integrated gasification combined cycle (IGCC) or oxyfuel combustion that will be combined with the CO_2 capture method.

This paper reviews the status of these three different approaches to electricity generation and associated capture of CO_2 from coal-based power plants. The paper also discusses the processes used to compress and transport captured CO_2 to storage sites, and the injection and monitoring processes that are used to secure the transported CO_2 in deep underground geologic formations.

Coal-based power generation and petroleum-based transportation emissions each have a dominant impact on national CO_2 emissions, both now and projected for 2030. If these two major sources of CO_2 cannot be reduced significantly, then US CO_2 emissions will in turn, not be reduced significantly. Figure 1 offers an insight into the critical importance of CCS technology in addressing a means to reduce CO_2 emissions from coal use.[7]

Carbon Capture

Three types of carbon capture systems are reviewed in this paper:

- Post-combustion systems (scrubbers), which generally use a chemical-based solvent (referred to as a "reagent") to separate and concentrate and then capture the otherwise dilute CO_2 in the flue gases of traditional power plants.
- CO_2 capture equipment that is part of gasification systems which separate the CO_2 from the fuel-gas, prior to conversion, rather than from the fuel-gas after combustion.
- Oxy-combustion systems that resemble traditional coal-fired power plants, but use pure oxygen rather than air for combustion, with the result that the flue gases are mostly CO_2 (without the nitrogen that results from combustion with air), and therefore do not require CO_2 scrubber systems.

Once the CO_2 has been captured (isolated) by any one of the methods identified above, then the CO_2 must be compressed into liquid, transported via pipeline, and injected into deep wells for long-term storage or used beneficially for other purposes, including, for example, EOR.

Post-combustion systems (traditional power plants)

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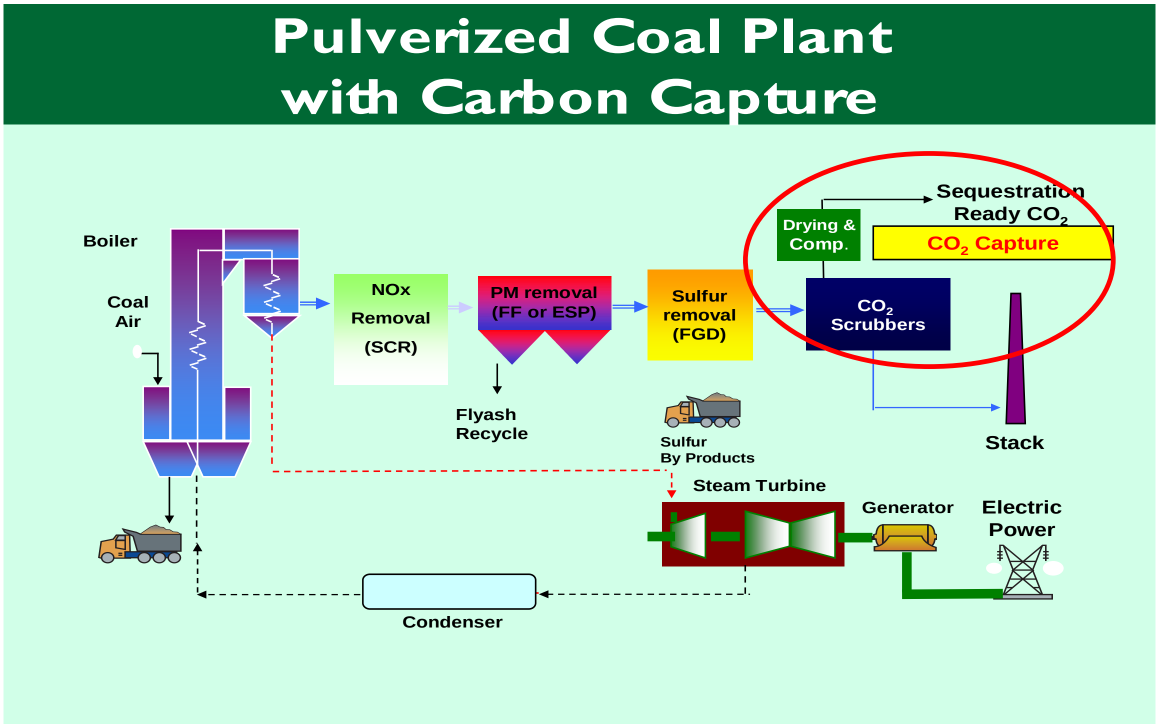
[6] See: Energy Technology Perspectives – 2008, International Energy Agency, June 2008; and Carbon Dioxide Capture and Storage, Intergovernmental Panel on Climate Change, 2005.

[7] Figure 1 was prepared by the DOE/Energy Information Administration, and can be found at: http://www.eia.doe.gov/environment.html .

Post-combustion CO_2 capture systems add a CO_2 “scrubber” to remove the CO_2 from combustion gases after all traditional regulated air emissions have been removed, and before the gases enter the power plant’s stack.



Pulverized Coal Plant with Carbon Capture

Existing commercially available technologies generally use an amine, a nitrogen-based chemical solution, which absorbs the CO_2 from the power plant’s flue gas. Then, in a separate vessel the liquid solution is heated and the CO_2 is released, in a very concentrated form. The concentrated gaseous CO_2 can then be compressed into a liquid for pipeline transportation (discussed later in this paper).

These post-combustion processes to capture CO_2 are commercially available today. For example, amines have been used to separate CO_2 from other gases in the oil/gas processing and petrochemical industry for 60 years. However, there are several deterrents to their deployment in coal based power generation applications:

- The current post-combustion technologies require significant amounts of energy to operate the capture system, particularly the heat needed to force the release of CO_2 from the solvent. This release is necessary in order to allow for the reuse or regeneration of the solvent. Also, significant amounts of electricity generated by the power plant are needed for the CO_2 compressors. This energy requirement is currently about 30% of the total energy used by the power plant.
- Contaminants in the flue gas can degrade the capture solvents and corrode process equipment which requires specific design measures and process adaptations.

- There has not been an attempt to integrate carbon capture and power production on the scale necessary to significantly reduce CO_2 emissions from typical, large-scale power plants. System integration is critical to minimizing the energy and solvent requirements for the capture system. Current CO_2 capture systems can increase the cost of electricity from the power plant, by as much as 75% compared to a conventional pulverized coal system that is not equipped with such CO_2 capture equipment.[8]

Government and industry have prepared multiple technology development “roadmaps” to overcome these barriers with improved technologies. These projected activities include both near-term (learning by doing) approaches, and longer-term research approaches.

Near-term approaches include application of improved solvent systems, like chilled ammonia and other proprietary chemicals, instead of traditional amines. These solvents offer the promise of much lower energy requirements. A few “pioneer” units demonstrating these technologies at commercial scale are already on the drawing boards, and could become operational in 5 to10 years. These “slip stream” demonstrations will be designed to capture up to 80% of the CO_2 contained in the process flue gas stream. The entire power plant’s flue gases do not need to be outfitted with the CO_2 scrubber because these technologies can be proven in smaller, less costly and less risky modular units. Once these units are proven successful, additional modules can be installed to capture additional volumes of the power plant’s CO_2 emissions. This same step-wise development model was used to develop the initial set of sulfur dioxide scrubbers. As discussed later in this paper, this same step-wise process would also be applicable to IGCC and oxy-combustion systems.

It is expected that the first pioneering demonstrations will be followed by a series of deployment projects. These deployment projects, the “first movers” or “early adopters” of the demonstrated technology, will increase the number of modules to capture greater volumes of CO_2 and may also incorporate improvements to the technology originally demonstrated in the pioneer facility. Work has not begun on such deployment units since it is necessary to await the outcome of the initial demonstration projects. Therefore, subsequent deployment of newer, more efficient technologies would expect to start around 2020 or later. Successfully demonstrated advanced post-combustion CO_2 scrubbers could be broadly deployed as early as the 2025 to 2030 timeframe.

Finally, continuing advanced research and development that could lead to dramatic cost reductions are also being pursued by public-private sector collaborations, and include: improvements to the post-combustion capture system; improved efficiency at the basic power plant, which reduces the amount of CO_2 needing capture; advanced solvents; solid sorbents; organic metals, and low grade heat integration schemes. Once developed, these technologies would

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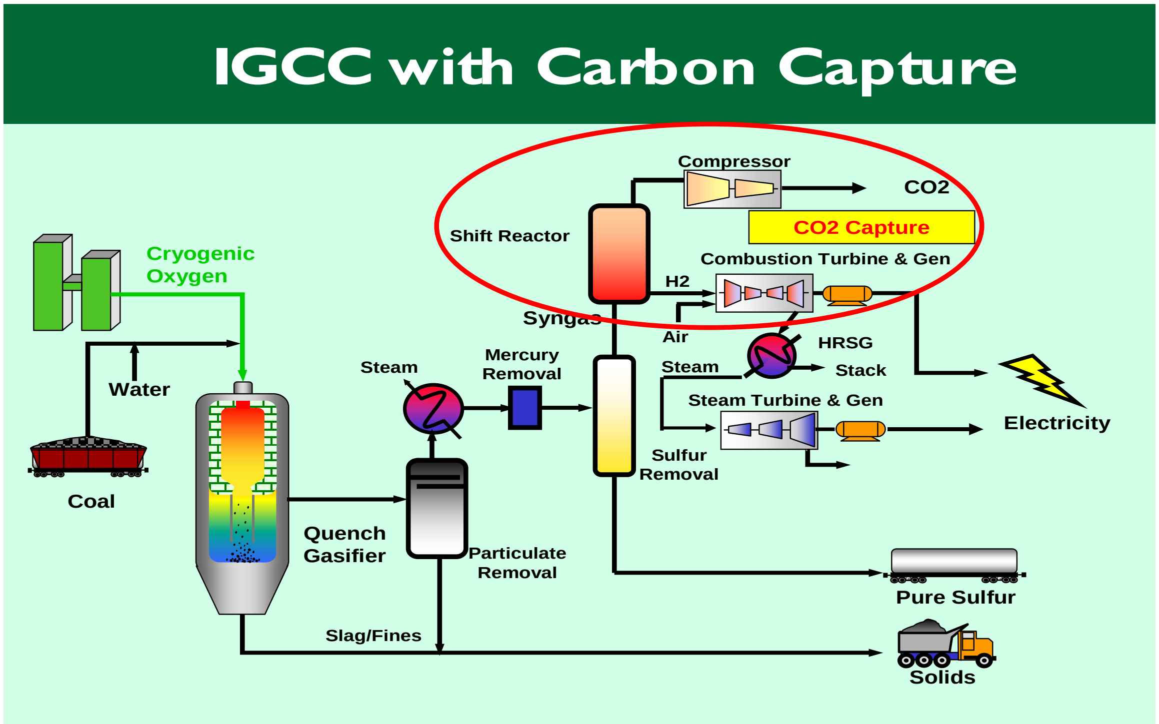
[8] DOE FEPP and Oxycombustion Coal Reports 2007/1291 Oct.2007 and 2007/1281 May 2007 (comparing SCPC w/CCS, IGCC w/CCS and OxyCombustion.

require commercial scale demonstration, as well. For these technologies, now only in the research phase, any deployment will not occur until 2030 and beyond.

Gasification Based Systems

Gasification based CO_2 capture systems work in a different manner than post-combustion systems. These systems take advantage of the fact that gasification produces a pressurized fuel gas (referred to as "synthesis gas") in a gasifier. This synthesis gas is cleaned and then used to generate electricity in a combined cycle power system (known as Integrated Gasification Combined Cycle (IGCC)).[9]



For IGCC power system applications, CO_2 capture should also be accomplished in a step-wise approach. Such an approach might begin with capture of the CO_2 naturally occurring in the coal gasifier, which would account for up to 15-20% of the total carbon emissions of the power plant. This step would use currently available technology and not result in a major increase in generation costs. The next technology step would add a process known as water-gas shift in which more of the carbon in the synthesis gas is converted to CO_2 and with the addition of a second acid gas removal (AGR) processing stage in the clean up process an increased amount of CO_2 in the synthesis gas is captured. This step would lead to the capture of 50 to 65 % of the plant's CO_2 – the equivalent of CO_2 emissions from a natural gas fired electricity generation plant.[10] To achieve higher levels

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[9] Gasification systems can also be configured to produce synthetic natural gas, or to be converted to liquid fuels or chemical feed stocks, which are not included here.

[10] Gasification systems already are equipped with an AGR system to remove hydrogen sulfide from the syngas. A second vessel would be required for CO2 capture. Typical processes used in AGR systems are Selexol and Rectisol, both proprietary processes commercially used in the chemical industry.

(up to 90%) of capture, more stages of water-gas shift and AGR are added to the plant.

The CO_2 capture processes described above are already familiar to the petroleum refining industry and are also used in facilities that produce ammonia for fertilizers from natural gas. These processes have not yet been optimized technically or economically for integrated power plant and CCS operation. These technologies then have some of the same challenges as post-combustion technologies when applied in power generation applications as well as some unique challenges including:

- Energy is needed to power the capture and compression systems, generally less than the amount needed for post-combustion systems, but still a significant percentage of the plant's power output.
- Capturing a high percentage of the CO_2 requires that the plant's gas turbines operate with a hydrogen rich fuel containing as much as 90% hydrogen. Today's state-of-the-art combustion turbines can burn a hydrogen-rich fuel, but not pure hydrogen. It is expected that when more efficient advanced combustion turbines are developed in the future, these future turbines will be capable of operating on hydrogen-only and, as a consequence very high CO_2 capture efficiencies of greater than 85% will be achievable technically and economically.[11]
- In a similar status as post-combustion capture and Oxy-combustion technologies, none of the current fleet of IGCC power plants has been integrated with a CO_2 capture system, and the integration issues are significant for power plants that must adjust load on a daily and seasonal basis.
- An IGCC CO_2 capture system is currently estimated to increase the cost of electricity produced by as much as 35 to 45% for IGCC systems that achieve 90% or greater CO_2 capture.[12] Today's IGCC power plant without capture (given its limited commercial-scale utilization at this time) is estimated to cost 10 -20% more than traditional pulverized coal systems.

Plans exist to overcome these barriers. In the near-term, the focus is on systems that use today's state-of-the-art technology without the installation of the additional hardware (e.g. water-gas shift and AGR hardware) that will enable subsequent IGCC plants to capture higher levels of CO_2. As experience is gained from integrating the power plant with CCS systems, this additional hardware can be added to subsequent units.

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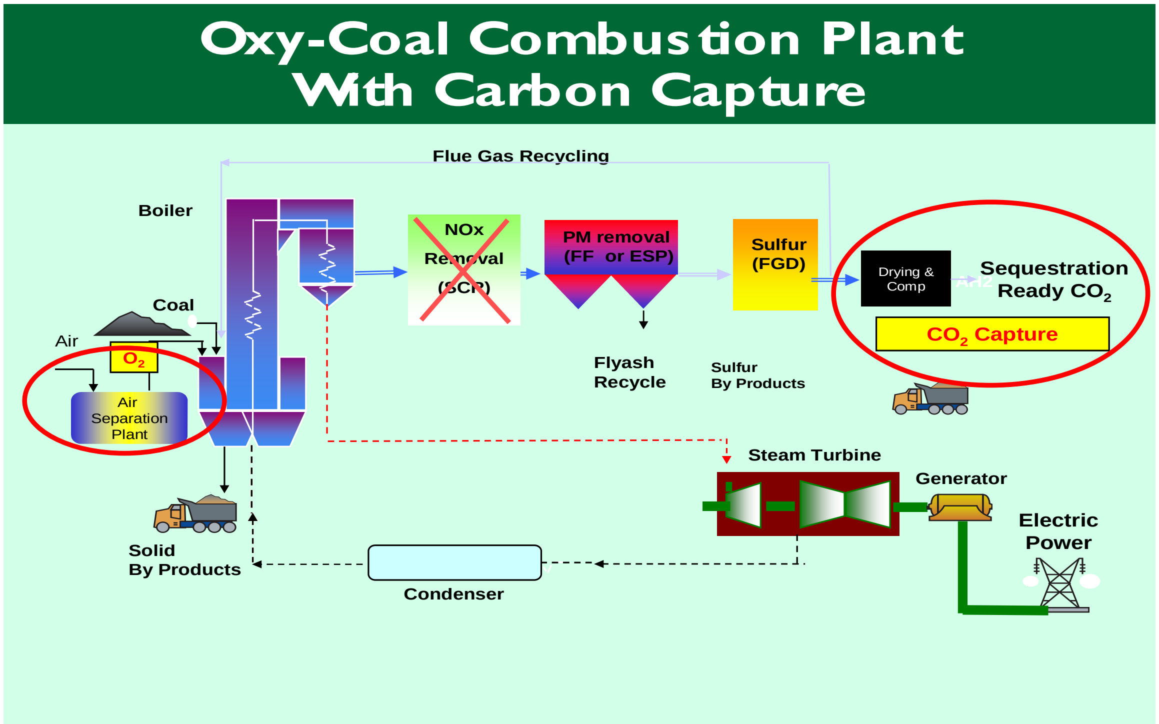
[11] Today's state-of-the-art large utility scale gas turbines (F class turbines) are commercially available to operate on the high H_2 syngas that is produced in an IGCC plant that captures CO_2. The more advanced H class gas turbines are not ready to operate on this high H_2 syngas. These advanced gas turbines can have a significant positive impact on the economics of an IGCC plant through their increased power output and better efficiency but these H class turbines are not ready for use in IGCC systems that capture most of the CO_2.

In the longer term, research is needed to reduce the cost and performance impacts of the IGCC CO_2 capture systems. These cost reductions and performance improvements are likely to result from R&D focused on higher efficiency catalysis for water gas shift, better CO_2 capture solvents, and higher efficiency, advanced gas turbines that can significantly improve overall plant efficiency and, thereby, lower the plant's CO_2 emissions. [Note: reinsert the comments re: FutureGen]

IGCC plants capable of capturing 15-20% of the plant's CO_2 could be operational within the next 5 years. The next level of capture (e.g., 50% to 65%) could be retrofitted to these early plants or made operational on follow-on "first mover" deployment units by 2020. Then multiple generation units capable of capturing up to 90% of CO2 emissions and benefiting directly from these early demonstrations, first-of-a-kind deployment projects as well as integrating successful R&D programs could be widely deployed in the 2025 to 2030 timeframe.

Oxy-combustion systems

Oxy-combustion systems generally resemble traditional pulverized coal or circulating fluidized bed power plants, with three modifications. First, oxygen, instead of air is used for combustion and therefore a large air separation unit (ASU) is added. This ASU supplies the oxygen needed for combustion. Second, because the combustion of coal with oxygen produces very high flame temperatures that exceed the limits of available metals, a portion of the clean CO_2 generated by burning the coal is recirculated back into the boiler to reduce the combustion temperature (such flue gas tempering systems are already used at a smaller scale on traditional power plants). Third, the CO_2 rich flue gas must be cleaned and processed to remove the normal coal pollutants (SO_2 and particulates) and water vapor prior to compression for transport and storage.


Oxy-Coal Combustion Plant
With Carbon Capture

There are several challenges that Oxy-combustion systems must overcome including:

- There is no experience with power plants burning coal with oxygen beyond large lab-scale units even though cryogenic air separation units for oxygen production have been in use for over 100 years and oxyfuel combustion at smaller scale has been used in industrial application.
- An oxygen production plant (ASU) is required because the entire process to combust coal uses oxygen rather than air. Also, a combined compression and purification (CPU) unit for the captured CO_2 is required. Both the ASU and CPU systems must be integrated into the overall power plant design and operation.
- The CO_2 recirculation system which will require varying levels of sulfur and moisture removal as well as boiler and control modifications, is on a scale not previously experienced.
- The oxycombustion capture system increases the cost of electricity by as much as 75% for the very high capture efficiency systems (>90% CO2 capture).

Efforts are underway both in the US and abroad to overcome these challenges to oxy-combustion. At this stage of development an oxy-combustion demonstration plant in the size range of 50 – 150 MWe gross is required. Once a plant of this size is constructed and demonstrated, then larger, commercial-scale deployment plants will follow. Such demonstrations are now being planned. Thus, the step-wise approach for oxy-combustion technologies involves building units in progressively larger sizes, while seeking additional cost reductions via lower cost oxygen systems and development of improved boiler materials that can allow oxy-combustion systems to operate within higher steam temperatures that will increase efficiency and power plant output. Also, it may be possible to eliminate costly systems that are currently used for nitrogen oxide emissions control by optimizing the combustion process in an oxy-combustion system using coal.

A small number of near-commercial scale demonstration units using oxy-combustion are already being considered, and could become operational in 5 to10 years. If these demonstrations are successful, it can be expected that larger-sized units will be planned and constructed in the period beyond 2020. After the first mover or early adopter deployment projects, then wide-scale commercialization may be possible in the latter half of the 2020 decade.

CO_2 Compression and Transport

CO_2 compression and transport are relatively mature technologies. Before the CO_2 can be transported by pipeline, it must be purified, any remaining water must be removed, and it is compressed to about 2,200 pounds per square inch, or about 150 times atmospheric pressure. The petroleum industry has extracted natural CO_2 from underground reservoirs, dried and compressed it, and transported it via steel pipelines to use with EOR for over 25 years. Nevertheless, opportunities exist to reduce compression costs and energy use through compressor technology improvements.

CO_2 Storage (Geologic Sequestration (GS))

There is consensus that CO_2 permanent storage in deep underground geologic formations (basically, salt water in porous rocks) has great technological potential and may be deployable on a widespread basis. However, there are still financial, institutional, regulatory, and technical challenges that remain. To address these challenges, multiple integrated CO_2 capture and storage system projects are needed to prove out the technology.[13] Also needed is an array of small, and intermediate and large-scale, CO_2 injection field tests in diverse geologies to adequately characterize and validate the U.S. geologic resource. DOE and industry-funded sequestration R&D, led by the Regional Carbon Sequestration Partnerships (RCSP), provides a good example of the suite of field tests and other projects that are required to help ensure that we can store the necessary amounts of the two billion tons of CO_2 expected to be generated annually by U.S. coal plants.

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[13] To address these challenges, multiple integrated, large scale (> 1 million tons / year) CO_2 capture and storage system projects are needed to prove out the technology. Since there are existing large industrial CO_2 emitters with relatively easily captured $CO_{2,}$ these should be supported and used to demonstrate larger scale storage and sequestration. When large scale post-combustion, pre-combustion and oxy-combustion plants come online, the storage and sequestration will have been proven. Such demonstrations may permit a gasification-based pre-combustion plant to capture and store at natural gas equivalent levels (~60%) at startup rather than scaling from 15-20% capture levels. There is tremendous logic in supporting and proving larger scale storage and sequestration on efficiently captured existing CO2 sources while the coal power plants (regardless of pre, post, or oxy) are built. This will enable the fastest progression to high CO2 capture and storage at the lowest overall cost.

The basic process for injecting CO_2 underground begins with identification of a suitable porous rock formation which is naturally "capped" by relatively impermeable rock strata, so that CO_2 injected into the target formation cannot rise vertically through the caprock. A well is then drilled into the porous structure, and CO_2 (as a supercritical liquid) is injected with enough pressure to overcome the existing "static" pressure within the porous formation. The formations are typically one-half mile to over one mile below the earth's surface. Over the life of a power plant, it is anticipated that several wells could be necessary, depending on the local geology. Additional monitoring wells are also needed to ensure that the CO_2 remains contained. When a formation has received its intended amount of CO_2, injection ceases, and the well is "completed" or plugged with concrete to ensure that it will not be a conduit for release of the permanently stored CO_2. Monitoring of the storage field continues for more than a decade after injection ceases to insure permanence.

The cost of transportation, injection and monitoring is projected to be relatively small compared to the costs of capturing CO_2. These costs will vary depending upon the local geology.[14]

Injecting and storing CO_2 below ground in some specific geological formations has been demonstrated, mostly at small scale, to be technically viable. For example, this process has been commercial at a small scale for certain acid gas injection systems in Alberta, Canada, since the 1980's. While larger-scale injection experience has been promising, mainly in conjunction with EOR or enhanced gas recovery (EGR), storage of CO_2 in a deep saline geologic formation has never been attempted with CO_2 from a power plant. The Sleipner project in Norway has been successfully storing, into saline formations, CO_2 co-produced with natural gas since 1996, with no recorded leakage.[15] However, storage of volumes like those from large sources still remains to be proven anywhere in the U.S. or the world.[16]

On the other hand, the potential sites identified by DOE/NETL for storage of CO_2 in saline formations appear sufficient to accept US power plant CO_2 emissions for

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[14] Transportation costs of CO_2 will vary greatly depending upon the length of pipeline required to transport the CO_2 from the power plant to the site of injection. If the captured CO_2 is transported over great distances then the cost of the pipeline could constitute a significant expenditure of the overall CCS system.

[15] The CO_2 sequestration project in Norway, the Sleipner project, uses an amine system to clean natural gas that is high in CO_2 content from their current natural gas well operations.

[16] Current expertise and experience with EOR, a proven technology, is useful for understanding sequestration. EOR operations inject about 35 million tons/year of fresh CO_2 (about 70 million tons/year with recycle) in the U.S., but this is spread over many individual locations. Although most EOR projects use naturally occurring CO_2 from underground deposits, projects like the Weyburn project, which captures CO_2 from a coal-to-substitute natural gas plant, have shown that coal-based energy systems can also be used with EOR systems. Much of the CO_2 used in an EOR operation could be contained underground indefinitely. EOR is different from CCS in that (1) smaller amounts of CO_2 are injected in individual EOR projects than contemplated for full-scale CCS projects, (2) EOR displaces one fluid (petroleum) with another (CO_2), whereas sequestration in saline formations instead pressurizes the reservoir, and (3) EOR is done to produce a product, whereas carbon capture and sequestration is a cost with no value-added product.

many decades, although these formations are region-specific and not readily accessible to all parts of the US.[17]

The major barriers to broad deployment of CO_2 injection in saline formations are:

- The scale of operations is well beyond our current experience, and is not easily simulated by computer models. "Learning by doing" is the only way to develop real expertise in storing such large volumes of CO_2 as power plants produce.
- Geologic formations are not all the same. Some have features that make containment more certain than others, and the best sites may not be where power plants are needed.
- There is general consensus that geologic sequestration is as safe as natural gas storage and EOR. However, the public's willingness to accept the storage of large volumes of CO_2 below ground remains uncertain. Education of all interested stakeholders is a critical-path issue for large-scale implementation.
- Monitoring, measuring and verification (MMV) remains an area of development with need for better tools to predict the capacity of reservoirs and the lateral and vertical movement of injected CO_2 over time. Technology, know-how and experience from the oil and gas industries are expected to be very useful in addressing these areas of need.
- Clear regulatory and legal protocols for injection of CO_2 into saline formations or elsewhere have yet to be developed. The EPA is pursuing a multi-year process to develop regulations related to groundwater protection. The Interstate Oil and Gas Compact Commission (IOGCC) has developed broader model statutes and regulations built largely on approaches that have worked with EOR, and several states have used these to develop state regulations. Clear regulations regarding property rights, aggregation of multiple parcels for storage systems, and possibly mechanisms for establishing eminent domain are needed before commercial CCS projects can go forward (see additional discussion below).
- A mechanism to address long-term storage integrity is also needed. CO_2 must remain stored for hundreds of years to make the effort worthwhile, from a climate perspective. A method to ensure nearly perpetual monitoring and leak mitigation must be developed. The IOGCC model rules point to one possible approach.

Basic research on storage is probably not as necessary to overcome these barriers as is actual experience and empirical data. To overcome technical barriers to storage, some storage projects, preferably at well characterized sites that are inherently low risk need to be built. To overcome regulatory barriers

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[17] Carbon Sequestration Atlas of the United States and Canada, USDOE/National Energy Technology Laboratory, March 2007.

protocols that are sufficiently flexible to protect the environment and ensure safe injection, but do not hinder the technology with unnecessary restrictions need to be established. The IOGCC guidelines may show the correct path to accomplish this.

Legal ownership and Liability Issues Related to CO_2 Storage

Legal ownership issues associated with ownership of geological formations and the right to inject above, in or below minerals is an area of great uncertainty for the progression of CCS. Equally, the liability related to CO_2 injection operations and long-term maintenance remains an uncertainty (and thus a potential barrier) to a large-scale storage project.

In the area of mineral ownership and the rights around CO_2 injection, some states are advancing legislation to address this issue, which needs to be resolved in order to develop the necessary infrastructure for commercial scale CCS projects. A related issue is the matter of permitting CO_2 injection projects. Permitting is being done for EOR injection and for small-scale testing in some states, but an acceptable standard framework for permitting full-scale operations remains an area of need. EPA, which began a formal rulemaking process by publishing a proposed rule for Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, is working closely with DOE, the Interstate Oil and Gas Compact Commission (IOGCC) and others to address this issue.

The liability related to a CCS project has several elements that include a local damage element (during operations and post-closure phases), a global damage element (for carbon reversal if there is leakage from the storage) and personal injuries (if there are personal or environmental damage that results from CO_2 leakage).

Conclusions:

The nation can continue to enjoy the economic and energy security benefits that flow from use of coal in our energy mix, if we follow a step-wise strategy for demonstration and deployment of CCS technologies integrated with coal based power generation options. The nature of this strategy varies, depending on whether the technology is being developed for conventional pulverized coal power plants, IGCC power plants, or oxy-combustion power plants, but generally includes using financial incentives to assist in the early (pioneering) demonstration of coal based power projects using CCS technologies, early deployment or first mover projects, and then initial widespread commercial deployment.

In addition to further development of CCS technologies, we also need to overcome certain institutional barriers to CO_2 storage, including resolution of property rights issues, and creation of a system to address long-term (multi-decade) monitoring and management of CCS storage sites. The IOGCC has worked with a broad coalition of stakeholders to develop model legislation and regulations for states to consider in establishing the needed rules. Several states have already used the model rules to adopt such regulations, and regulations are under development in additional states.

The state of CCS technology is such that we are ready now to launch demonstration projects. Such projects could be operational within 5-10 years, and follow-on deployment projects achieving greater percentages of CO_2 capture and incorporating improvements in the technology could be operational within the 2020 to 2025 timeframe to then be followed by widespread commercialization thereafter.

Legal issues associated with ownership of geological formations, the rights to inject above, in or below minerals in an area and short and long term liability for fugitive CO_2 leakages are all matters of great uncertainty. A number of states have under consideration legislation to address these issues. In order to develop the necessary infrastructure for commercial scale CCS projects it may be necessary to develop a consistent national program. Importantly, to support the demonstration of near-term CO_2 capture projects that are integrated with power generation facilities it will be necessary to develop interim programs to address these issues so that these projects might proceed forward even while the legal and regulatory structures for the long term are developed and adopted.

Permitting is being done for EOR injection and for small-scale testing in some states, but an acceptable standard framework for permitting full-scale operations remains an area of need.

Monitoring, measuring and verification remains an area of development with need for better tools to predict the capacity of reservoirs and the lateral and vertical movement of injected CO_2 over time.

For some, long-term liability for CO_2 injected below ground remains a deterrent to long term CO_2 storage. Although it is presumed that individual or corporate sequestration operators will have to assume some risk during the operating phase and for some time post-closure, they will be unable to take the risk associated with the potential release of sequestered CO_2 in perpetuity, and some Government based scheme must be devised to overcome this barrier.