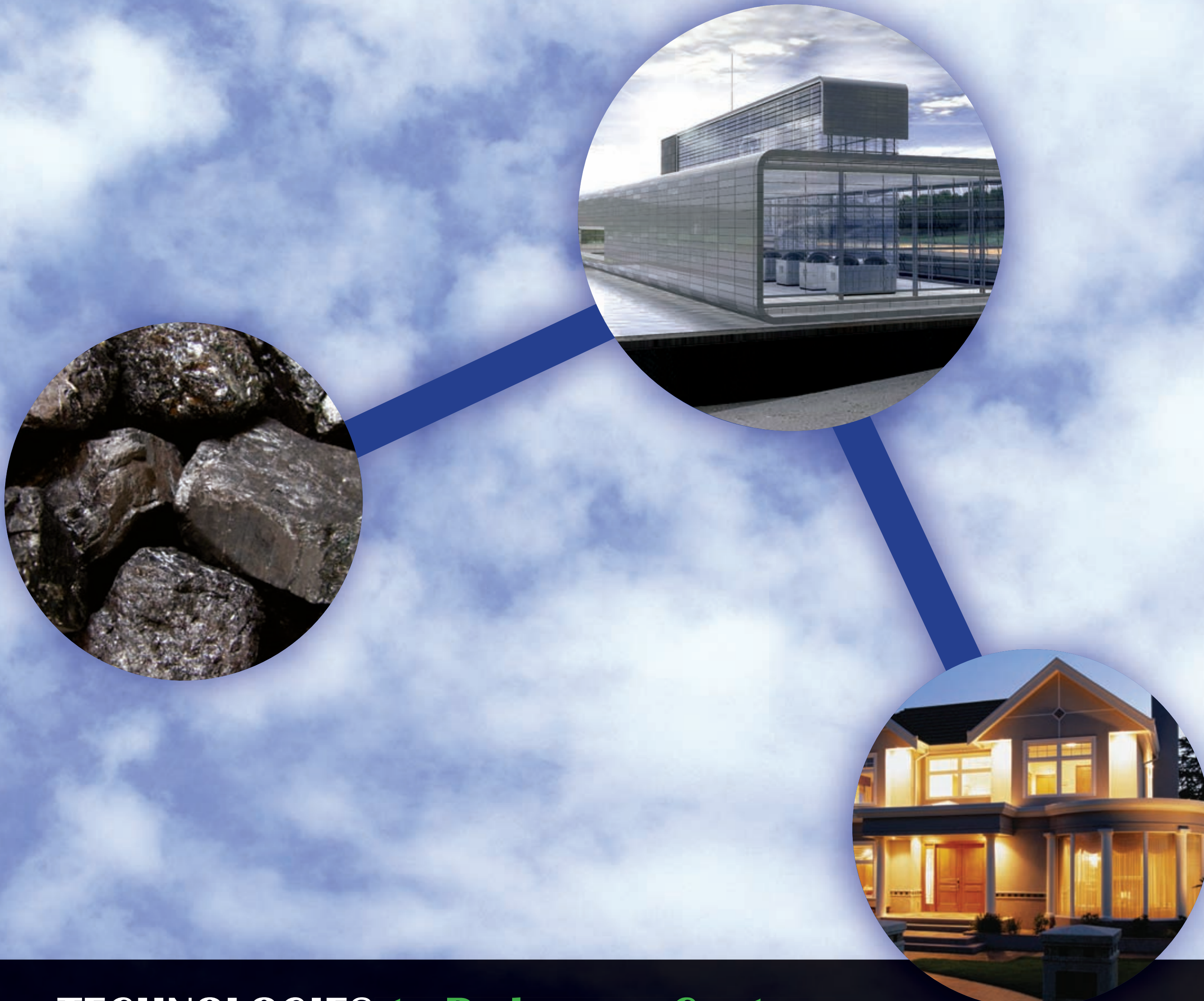

TECHNOLOGIES to Reduce or Capture and Store Carbon Dioxide Emissions

A report for the Secretary of Energy describing technologies to continue the evolution toward near-zero emissions from coal-based generation.

THE NATIONAL COAL COUNCIL

June 2007

COAL must continue its vital and growing role in energy production in the United States, supplying the energy for more than 50% of the nation's electricity production.

Reducing carbon dioxide emissions presents a significant technological challenge, but the coal industry has a proven record of successfully meeting such challenges. It is imperative that research, development and demonstration efforts move forward quickly on a portfolio of technologies to reduce or capture and store carbon dioxide emissions.

Public-private support for technologies to reduce or capture and store carbon dioxide is critical to the United States energy independence and national security.

TECHNOLOGIES to Reduce or Capture and Store Carbon Dioxide Emissions

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Georgia Nelson

PTI Resources

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Ameren Energy Fuels and Services

STUDY CHAIR

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U.S. DEPARTMENT OF ENERGY

Samuel W. Bodman

Secretary of Energy

The National Coal Council is a Federal Advisory Committee to the Secretary of Energy. The sole purpose of The National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or the coal industry.

The Secretary of Energy
Washington, D.C. 20585

June 26, 2006

Ms. Georgia Nelson
Chair, National Coal Council
1730 M Street, NW
Washington, D.C. 20036

Dear Ms. Nelson:

Thank you for your May 4, 2006, letter stating that the National Coal Council (NCC) proposes to conduct a study of technologies available to avoid, or capture and store, carbon dioxide emissions – especially those from coal based electric utilities.

We understand that this report will expand upon the findings and recommendations of two previous reports submitted by the NCC entitled, *"Coal-Related Greenhouse Gas Management Issues"* (May 2003) and *"Opportunities to Expedite the Construction of New Coal-Based Power Plants"* (November 2004). We also understand that this report will focus on technologies available to the existing fleet of coal-based electricity generation plants as well as new and innovative technologies needed for future plants. It is also important for the discussion in the report to culminate in a recommended technology-based framework for mitigating greenhouse gas emissions from those plants.

In conjunction with industry and academic partners, the Department of Energy has already undertaken a great deal of research in the area of carbon capture and storage. Much of this work has been or will be conducted with the FutureGen Alliance, the Carbon Sequestration Regional Partnerships, the Carbon Sequestration Leadership Forum, and others. We encourage you to work with the members of these groups as closely as possible.

We also agree with your suggestion to assess the potential impact of the provisions of the Energy Policy Act of 2005 on the carbon management issue. It is our intention to use this study to provide a strong foundation for the continuing development of a technology based strategy for managing carbon and trust that it will act as a catalyst to promote additional public-private partnerships in the area of carbon capture and storage.

We believe that the NCC membership represents a broad spectrum of senior level industry, State, academic, and public interest organizations and is well positioned to complete this study.

I am designating Mr. Jeffrey D. Jarrett, Assistant Secretary for Fossil Energy, and Mr. George Rudins, Deputy Assistant Secretary for Clean Coal, to represent me in the conduct of this important study. Mr. Jarrett is available at (202) 586-6660; Mr. Rudins can be reached at (202) 586-1650.

I offer my thanks to the NCC for its efforts in assisting the Department of Energy in defining the scope of this study request. We look forward to receiving this study when completed.

Sincerely,

Samuel W. Bodman

Samuel W. Bodman

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FAX: 202-223-9031

Website Address: nationalcoalcouncil.org

June 7, 2007

The Honorable Samuel W. Bodman
Secretary of Energy
U. S. Department of Energy
1000 Independence Avenue, S. W.
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of The National Coal Council, we are pleased to submit to you, pursuant to your letter dated June 26, 2006, the report, "Technologies to Reduce or Capture and Store Carbon Dioxide Emissions." Technologies to reduce, capture and store carbon dioxide (CO_2) emissions are being developed in response to national and international concern about climate change. Even though many components of these technologies exist, significant additional research, testing, and eventually, operational experience at commercial scale electricity generating plants is needed. Technologies to address CO_2 emissions are at early stage of the technology development curve.

This report focuses on a broad suite of technologies to reduce, capture and store CO_2 emissions, primarily as they relate to direct coal combustion and also coal gasification and liquefaction. The report surveys and summarizes existing research, discusses relevant federal programs, makes recommendations regarding additional research opportunities and public policy objectives, and recommends a technology-based framework for mitigating CO_2 emissions from coal-based electricity generation plants.

It is evident that the Department of Energy is already at work to foster the development of these technologies. We would be remiss if we did not thank you for the Department's already significant efforts and valuable programs in this area. The report recognizes the scope of that work and in essence, concludes that much work still remains.

Coal will continue to play a vital role in energy production, not just in our country, but around the world. Reducing CO_2 emissions presents many significant technological challenges, but the coal industry has a proven record over the past 40 years of successfully meeting such challenges. Technologies to dramatically reduce particulates, sulfur dioxide (SO_2), oxides of nitrogen (NOx), and metals continue to improve and provide benefits. With proper planning and research, technologies to manage CO_2 emissions likewise will be developed and deployed.

These technologies cannot be simply willed into existence, but their development can and must be expedited. It is imperative that research, development and demonstration efforts move forward on a portfolio of technologies for CO_2 emissions control. And public-private partnerships should play a key role in speeding up the commercialization of these technologies.

Any framework for managing CO_2 emissions must take into account the realities of the existing infrastructure of energy production and use in our nation. Immediate opportunities focus on efficiency improvements within the current fleet of plants. These gains can be made at several points within the system and include turbine blade upgrades, condenser system and boiler feed water system improvements, washing and cleaning the coal that is used and improving the milling systems used to grind the coal. The development of regulatory incentives would dramatically speed up achievement of these efficiencies.

Along with a focus on existing plants, we must take advantage of efficiency gains that can be achieved in new plants. The use of supercritical, ultra-supercritical, integrated gasification combined cycle and other advanced clean coal technologies can raise the efficiency of new plants substantially. Also, streamlining the permitting process for new plants can reduce construction costs and provide incentives for operators to employ these cleaner technologies.

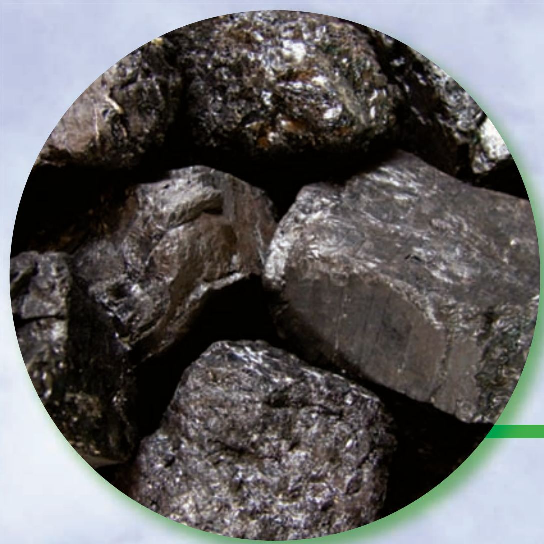
But, ultimately, a robust commitment to developing carbon capture and storage (CCS) technologies is required. Technology for CCS, including storage sites and related infrastructure, must be developed within the next 10 years. Legal liability questions must be answered during this time period as well. Several major CCS projects must be started as soon as possible so as to achieve commercialization within the next 15 years. Ideally, all of this will be done within the context of public-private partnerships in order to more quickly bring these technologies to the marketplace. These technologies will be implemented as they become available, affordable, and deployable.

Thank you for the opportunity to conduct this study. We believe it responds thoroughly to your letter of request, and the Council stands ready to answer any questions on its content.

Sincerely,

Georgia Nelson
Chair
The National Coal Council
President and CEO
PTI Resources, Inc

Mike McCall
Chair
The National Coal Council Study Group
Chairman and CEO
TXU Wholesale



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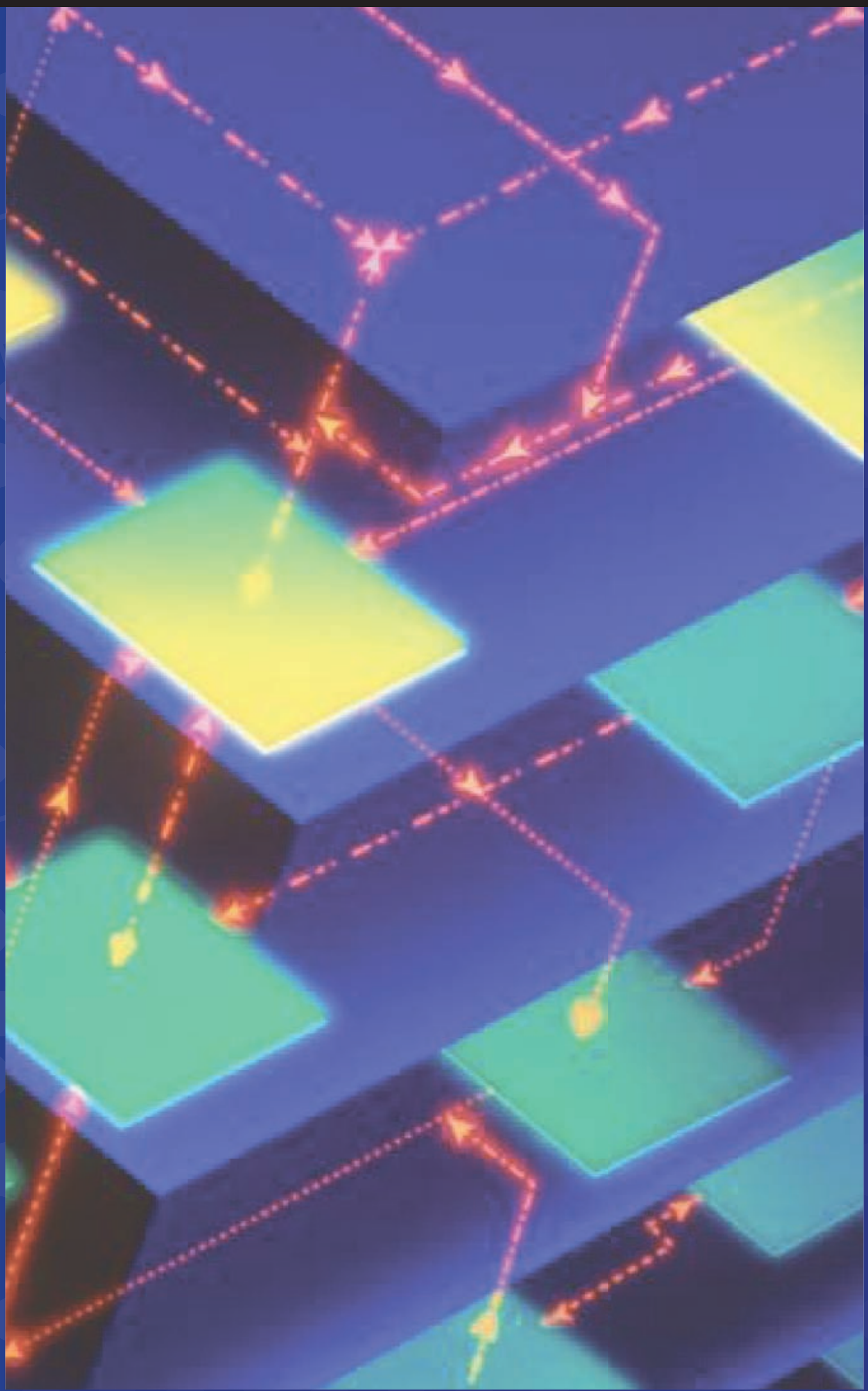
THE NATIONAL COAL COUNCIL

TECHNOLOGIES to Reduce or Capture and Store Carbon Dioxide Emissions



EXECUTIVE SUMMARY

By letter dated June 26, 2006, Secretary of Energy Samuel W. Bodman asked the National Coal Council (NCC) to "conduct a study of technologies available to avoid, or capture and store, carbon dioxide emissions – especially those from coal-based electric utilities." He also requested that the report "culminate in a recommended technology-based framework for mitigating greenhouse gas emissions from those plants." The full text of Secretary Bodman's letter can be found on page iii.

In response to the first task, this report examines a suite of technologies focused on carbon dioxide (CO_2) emissions management. The study provides a current status overview of key technologies, describes the challenges they face in development and commercialization, and makes findings and recommendations concerning what needs to be done to make these technologies available in the marketplace.[1]

The second task, recommending a framework for mitigation of greenhouse gas emissions, has its foundation in the response to task one. The framework discussion begins on the following page, but it also is embodied in the report Conclusions and the specific NCC Recommendations found at the end of the Executive Summary.

The Council accepted these tasks. The coal industry stands ready to rise to the challenges and concerns about carbon dioxide emissions. The industry has successfully managed to address emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X) and is now tackling mercury. Although they should not be expected to develop overnight, vigorous research, development and demonstration efforts can bring about a suite of technologies that are available, affordable and deployable. It is imperative that significant progress be made on these technologies so that any carbon management programs enacted by the government can be achieved.

STUDY MISSION STATEMENT

This report focuses on technologies to avoid, reduce, capture and store CO_2 emissions, primarily as they relate to coal combustion and gasification in the United States. The intent of this report is to:

» examine a suite of technologies, providing current status and challenges, from which companies can investigate the most appropriate applications for specific needs and conditions

» survey and summarize existing research

» discuss relevant federal programs

» make recommendations regarding additional research opportunities and public policy objectives

» recommend a technology-based framework for mitigating greenhouse gas emissions from coal-based power plants

[1] The findings and conclusions in this report also build upon the knowledge gained from the previous NCC report, "Coal: America's Energy Future," issued in March 2006.

TECHNOLOGY-BASED FRAMEWORK FOR MITIGATING GREENHOUSE GASES FROM COAL-BASED ELECTRICITY PLANTS

Any framework must be based on the realities of the existing infrastructure of energy production and consumption. It is a near certainty that the use of coal will continue to grow worldwide over the next 25 years. In 2003, the world used 5.4 billion tons of coal, equal to about 96.2 million tons a week. By 2030, coal use is estimated to reach 10.5 billion tons a year, almost double the current use. Investments in technology offer the opportunity to accommodate the world's growing need for affordable energy while reducing CO_2 emissions and other environmental impacts.

The 2030 projection is on its way to reality. From 2003-2010 alone, the Energy Information Administration (EIA) has reported over 100,000 megawatts (MW) of coal-based power generation has been or is being built in China. These are not "planned" or "projected" megawatts; they are plants that have already been built or are under construction. Further, from 2010-2015, EIA forecasts another 90,000 MW of coal-based generation will be built. Many of these plants are also under construction. Add to this the new coal plants being built in other countries with a large indigenous supply of coal, such as India, Indonesia, Russia and the United States, and it is easy to see that the 2030 projection is well on its way to reality. Even Japan, which relies mostly on imports, is projecting a dramatic increase in the use of coal during this period. Given this huge world-wide demand for coal and other fossil fuels, control of greenhouse gas emissions must be based on technologies that can cost-effectively reduce or capture and store CO_2 emissions.

The nation must pursue CO_2 management technologies and policies that allow economic growth, support development and demonstration of technologies to improve efficiency, capture CO_2, and transport and store CO_2. The nation will benefit from technologies that can simultaneously address climate change, reduce emissions and improve energy security.

TECHNOLOGY MATURATION

All technologies have a maturation curve. Experience teaches that early in development of new technologies, predicted costs and construction lead times for initial full-scale projects are often underestimated because forecasts tend to be based on optimistic lab-scale projections. Although engineering-economic studies of advanced coal and carbon capture and storage (CCS) technologies attempt to take this into consideration, initial full-scale applications may still be costly until experience provides a basis for accurate performance, reliability and cost projections.

Large capital-intensive technologies tend to have longer development cycles. This is due to the sheer time and expense for each "design and build" iteration (compare, for example, the time-to-market difference between a power plant technology and a computer chip). For high-efficiency coal and CCS technologies, the design and construction cycle is three to five years – not counting the potential for delays in permitting. Even if all goes well, the technology will take several cycles to mature to the "nth" plant cost level. Cost estimates for commercial-scale demonstration units can often double in constant dollars from early research projections. Costs are often highest at the point of the first full-scale demonstration, when components, systems, controls and test programs are truly integrated for the first time. Costs eventually decline as benefits accrue from economies of scale, design improvements, efficiency upgrades, experience-based learning, and competition. This process has been studied for many technologies in the electric utility and other industries.

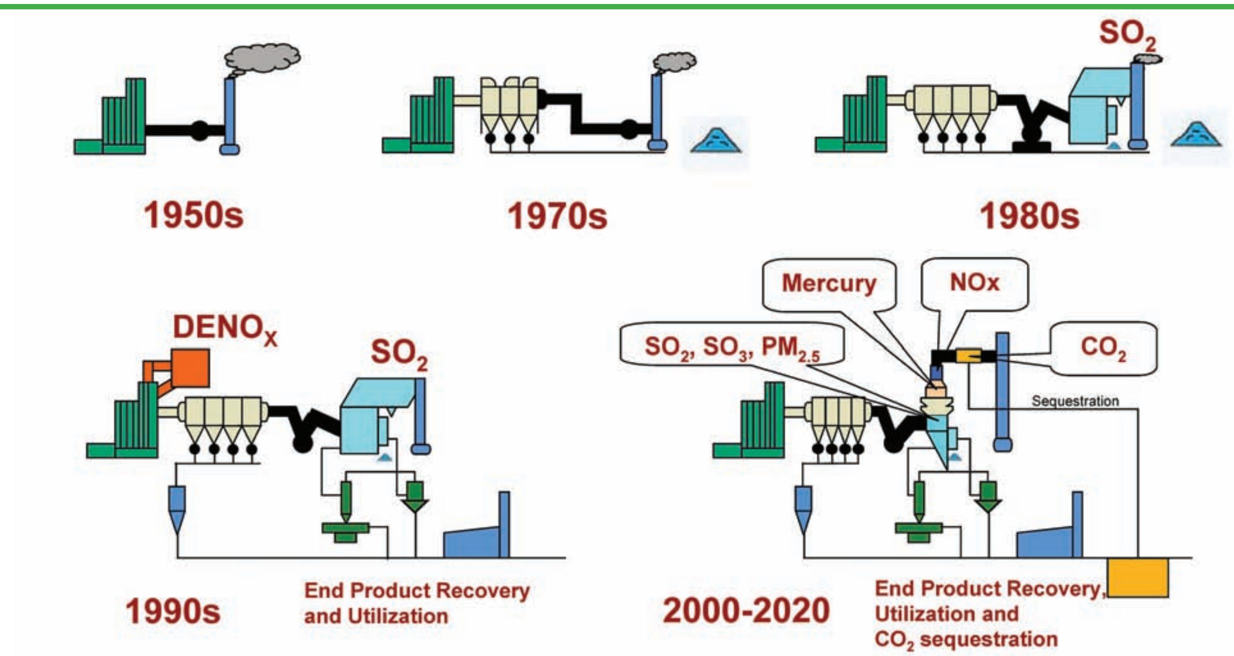


Figure ES-1

Evolution of Coal Fired Power Plant Emissions Capture[2]

The history of flue gas desulfurization (FGD) technologies, in the U.S. is a prime example. *See Figure ES-1*. In the early 1970s, FGD systems (commonly referred to as "scrubbers") were not very reliable or efficient. As experience was gained over time, efficiencies increased from about 70 percent removal of SO_2 to today's 95-98 percent. Reliability has also improved such that if the plant is running, the scrubber is running. But achieving this success took 20 years. Similar time periods to achieve success can be found with technologies to remove NO_X, and now technologies to remove and monitor mercury are in the early stages of a similar maturation curve. The drivers in both the SO_2 and NO_X cases were the same: sound, science-based technology R&D and regulations which recognize technology development and maturation. Both drivers also will be needed for the deployment of CCS.

A maturation curve for CCS technologies will similarly take time. Although some CCS technologies are commercial at smaller scale in other industries, these require substantial re-engineering and scale-up for power applications. Other promising novel CCS technologies are in their infancy. Based on advances to date, however, accelerated technical and financial support could make a suite of these technologies commercially available within the next 15 years. Commercial maturity may take an additional decade. CCS technology development can be expedited, but not willed into existence overnight by changes in policy.

MATURITY TAKES TIME

Commercial maturity could take an additional decade. CCS technology development can be expedited, but not willed into existence overnight by changes in policy.

[2] *Ohio Coal Development Office.*

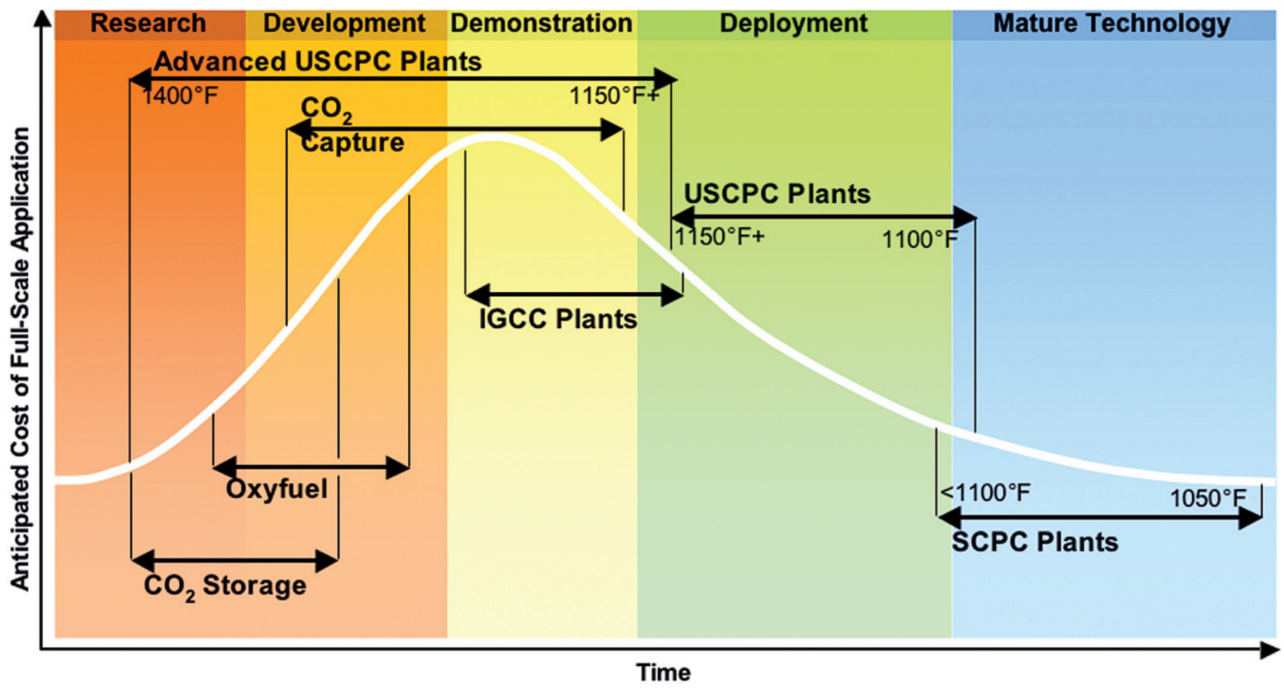


Figure ES-2

New Technology Development Curve for Coal[3]

Figure ES-2 depicts the relative developmental state of the major advanced coal and CCS technologies. This topic is explored further in Section 6.

HERE AND NOW

CO_2 mitigation technologies that are commercially feasible today are based on efficiency gains that can be achieved at existing plants and built into new plants. For existing plants, several technologies are available that can be retrofitted. In May 2001, the National Coal Council produced a report at the request of then-Secretary of Energy Bill Richardson (submitted to his successor, Secretary Spencer Abraham), which identified technologies that at that time could increase the amount of electricity from the existing fleet of coal plants by 40,000 MW. The approach set forth in those recommendations remains viable today although many of those opportunities may have already been implemented. To some extent, those strategies will also result in corresponding reductions in CO_2 production. While the 2001 study did not specifically address carbon emissions, and not every unit is a good candidate for every technology, the potential energy savings at a given plant can range as high as 10 to 12 percent, with typical efficiency opportunities that are perhaps half that level. A 5 percent improvement in the efficiency of the overall coal fleet would equate to about 100 million metric tons per year of reduced CO_2 emissions.

These efficiency gains can be made at various points within these plants. They include steam turbine blade upgrades, improvements in condenser systems and boiler feed water systems, and in the milling systems used to grind the coal. In addition, the use of coal cleaned to higher quality levels can

[3] *Various PowerPoint presentations, EPRI, April 2007.*

increase efficiency. The recommendations can be found in the Council report, "Increasing Electricity from Coal-Fired Generation in the Near-Term."

Plant efficiency upgrades are a practical, quick and less expensive way to reduce CO_2 emissions in the near term. Given current clean air regulations, however, many power plant owners would not initiate helpful upgrades because of concerns that such improvements would trigger more expensive plant upgrades because of New Source Review (NSR). Dialog between the U.S. Department of Energy (DOE) and the Environmental Protection Agency (EPA) on how best to achieve progress on this issue would be beneficial.

UPGRADE CONCERNS

Power plant owners may be reluctant to take steps to improve efficiency and reduce CO_2 emissions for fear that these improvements could trigger NSR requirements leading to large and expensive plant modifications.

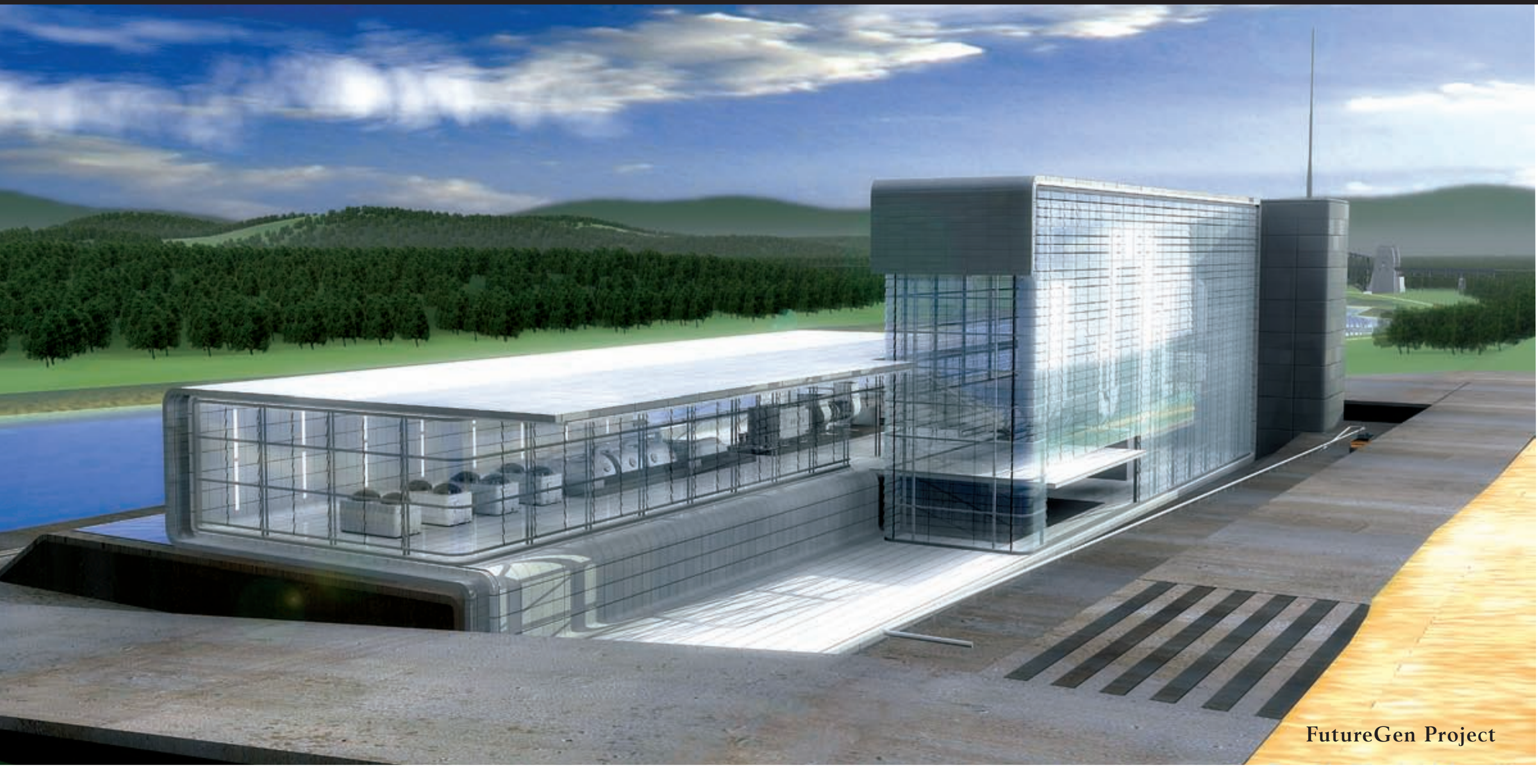
THE IMMEDIATE FUTURE

Another key to a real, technology-based framework is to address new plant construction. This report discusses several advanced clean coal technologies that are in the marketplace today and available to mitigate greenhouse gas emissions. During this initial period, before CCS technologies become readily available, energy efficiency is the best method to reduce carbon emissions. These include, but are not limited to, integrated gasification combined cycle (IGCC) technology and ultra-supercritical combustion technologies. These technologies can increase plant efficiencies from the 33-35 percent range up to as high as 45 percent for centralized power plants.[4]

The main issue surrounding these technologies centers on the fact that they are more expensive to build and, in some cases, operate than the traditional subcritical pulverized coal plants. Past incentives to expedite the use of these technologies have focused on this cost issue, either through government grants or loans or cost-sharing partnerships. And as these technologies mature, investment tax credits are needed to speed deployment while initial costs are high. While these incentives have their use, and should continue, other incentives for building plants using these advanced technologies should be provided.

For example, the actual construction of a plant takes 36-42 months. The permitting process adds as much as five years. An unintended consequence of today's process is that long permitting times delay replacing older technology with newer, more efficient and cleaner technology. One way to address this issue would be to significantly streamline the permitting process. This would still allow stakeholder input, but upon a final decision, the permits would be issued and the plant built, making the total project cost much less and the time for cost recovery to the company much shorter. The end result would be more power plants using advanced clean coal technology and mitigating greenhouse gas emissions through efficiency gains.

[4] Centralized coal-fired power plants have traditionally operated at about 30 percent efficiency on a higher-heating value (HHV) basis. Thus, HHV efficiencies in the 40 percent range or higher represent a significant improvement.



FutureGen Project

REAL DEMONSTRATION PROJECTS

One of the most successful technology-based programs in the nation's history was the Clean Coal Technology program initiated in 1985. Successors to this program continue today, but for the most part the program was completed by 2000. Over that 15-year period, major technologies were researched, developed, demonstrated and deployed at numerous coal-based electricity plants around the country. Any successful framework must include a similar commitment to CCS technologies. Demonstration projects for a new level of ultra-supercritical power plants would also be appropriate because the plant requires the development of new high alloy materials that would carry a capital expense premium with, at least in the first instance, no real guarantee of the long-term efficiency and reliability necessary to justify the increased costs. The potential overall efficiency gains and accompanying environmental benefits should more than justify policies to support initial demonstrations of these technologies.

Several CCS projects need to be initiated under real world conditions and at real world scale. An example is the recently announced American Electric Power (AEP) decision to install Alstom's new post-combustion technology, known as chilled ammonia, for capturing CO_2 emissions from two existing plants. Starting with a "commercial performance verification" project in mid to late 2008 in West Virginia, AEP will move to the first commercial-sized project at one 450-MW coal-fired unit at Northeastern Plant in Oklahoma by late 2011. This would capture about 1.5 million metric tons of CO_2 a year, which will be used for enhanced oil recovery. The West Virginia project will include storage of CO_2 in deep saline reservoir formations beneath the plant site, based on work by Battelle funded primarily by $7 million in contributions by the DOE at the same time. Another project announced by AEP at the same time is the installation of Babcock & Wilcox's oxy-coal technology at full scale on another power plant. The commercial scale plant is expected to be in service in the 2012-2015 timeframe, with the captured CO_2 likely to be stored in deep geologic formations. The storage portion of each of these projects involves a partnership with Battelle. These are just two technologies, at three plants, involving a small number of companies. Additional projects are essential to moving a competitive suite of clean coal technologies forward. Next-step projects need to be diverse in terms of geographic location, type of clean coal technology, and method of CO_2 storage.

The DOE can facilitate many similar projects, and must lead and expedite any framework for mitigating greenhouse gas emissions. These projects should be initiated as soon as possible to produce in the next five years operational data that will allow companies to choose the best applications for their needs from a full menu of options based on engineering, economics and geography/geology. A framework needs to include small-scale projects, such as CO_2 injection into geological formations coupled with long-term monitoring, to provide a strong foundation for future CCS deployment, as well as large-scale demonstrations that can fully test and evaluate the integration of generation, capture, transportation and storage technologies.

RETROFIT PROJECTS

AEP, in partnership with Alstom, Battelle, and B&W have announced three separate CCS projects. A chilled ammonia "commercial performance verification" project with deep saline reservoir storage planned to be operational in 2008 in West Virginia. The project is expected to be scaled up and installed with EOR on a 450 MW unit in Oklahoma by 2011. Oxy-coal with deep saline storage is also planned to be in service in 2012-13 timeframe.

A SERIOUS DISCUSSION

Coal is not the only source of greenhouse gas emissions, nor is it the only source for electricity in the nation. Any framework for mitigating greenhouse gas emissions must involve the full energy spectrum. With the projected growth in energy consumption, the country will need every ton of coal, cubic foot of natural gas, pellet of uranium, wind turbine, solar panel and Btu it can produce. Increased efficiency will also need to provide a significant and meaningful contribution.

A framework for mitigating greenhouse gas emissions has to seriously address the broad context of energy production and use. It is forecast that the nation will increase its energy consumption dramatically by 37 percent over the next 25 years. Renewable energy, along with end-use energy efficiency and demand side management, will continue to play an important and growing role in meeting this increased demand for power. Renewable energy sources such as wind, solar and biomass, however, simply cannot meet the projected electricity production or reliability the nation's economy requires. The bulk of the country's near-term electricity demand will continue to be met with coal-, nuclear- and natural gas-based generation. Coal will continue to supply about half the nation's electricity well into this century.

Solutions to meet the future energy needs of this nation must also recognize national security concerns. Coal is domestically available in large quantities, can be safely and securely transported around the country, is less subject to foreign market pressures in terms of cost or availability, and its use has become increasingly cleaner with innovation and technology development. Any serious discussion of coal's future role in a carbon-constrained world must include the fact that while its use has doubled over the past 35 years, emissions such as SO_2 and NO_X have markedly decreased. According to the U.S. EPA's Annual Trends

Report, this country's air is the cleanest it has been since the end of World War II.[5]

LOOKING TOWARD THE FUTURE

The framework for mitigating greenhouse gas emissions is simple conceptually – but difficult in terms of marshaling the requisite financial commitments, resolving legal and regulatory uncertainties, and instituting appropriate risk-sharing mechanisms. Necessary actions include:

» **Near Term:** Efficiency improvements at existing plants should be expedited. This can be achieved both technically and economically, but regulatory barriers must be addressed including modifying the NSR process. In such cases, NSR should not be triggered for plant efficiency improvements that reduce CO_2 emissions with no subsequent increase in SO_2 or NO_X emissions.

» **Mid Term:** Advanced clean coal technologies such as IGCC and ultra-supercritical combustion must be given public policy support in the form of cost and permitting incentives and financial support for initial demonstrations so they can succeed in the marketplace. Legal questions about liability for long term storage must be addressed. Sure-footed and steady progress on the FutureGen project is very important.

» **Long Term:** Technology for CCS, including storage sites and related infrastructure, must be developed and demonstrated over the next 10 years. Several major CCS projects must be started as soon as possible in order to achieve commercialization within the next 15 years. Oxygen firing technologies are designed specifically for carbon capture and will not develop independently of storage and infrastructure.

Ideally, all this is done in the context of public-private partnerships to more quickly bring these technologies to a state of commercial deployment.

Within the next 15 years, a suite of carbon capture technologies and storage facilities must become commercially available and affordable. When this happens, the coal-based electricity generation industry will be able to build these technologies into new plants and retrofit these technologies at existing plants where appropriate. In the long run, when these technologies become available in the marketplace, other nations using coal can also access them at more reasonable cost.

REPORT CONCLUSIONS

In support of the above framework for mitigating greenhouse gas emissions, the National Coal Council encapsulates the key conclusions from the report that follows:

Section 1 World Energy and Greenhouse Gas (GHG) Emissions Context

» The nation must pursue climate change policies that allow economic growth, support development and demonstration of technologies to improve efficiency, capture greenhouse gases, and transport and store carbon dioxide. The nation will benefit from technologies that can simultaneously address climate change, reduce emissions and improve energy security without damaging the domestic economy or the ability of U.S. business to compete in the global market.

[5] *U.S. Environmental Protection Agency Air Quality Trends Report, 1940-2005.*

» The coal and power industry will continue to develop CCS technologies for all generation types (advanced coal combustion and gasification technologies), but needs incentives to be able to do so within the timeframe the technologies are needed to address the climate change issue.

» The U.S. must develop strategies to help developing nations adopt CCS technologies as well. By ardently pursuing the required RD&D, these technologies will advance more quickly, thus becoming more cost effective and attractive to developing nations.

» When the costs of CCS technologies are driven down to economically feasible levels, they will be deployed.

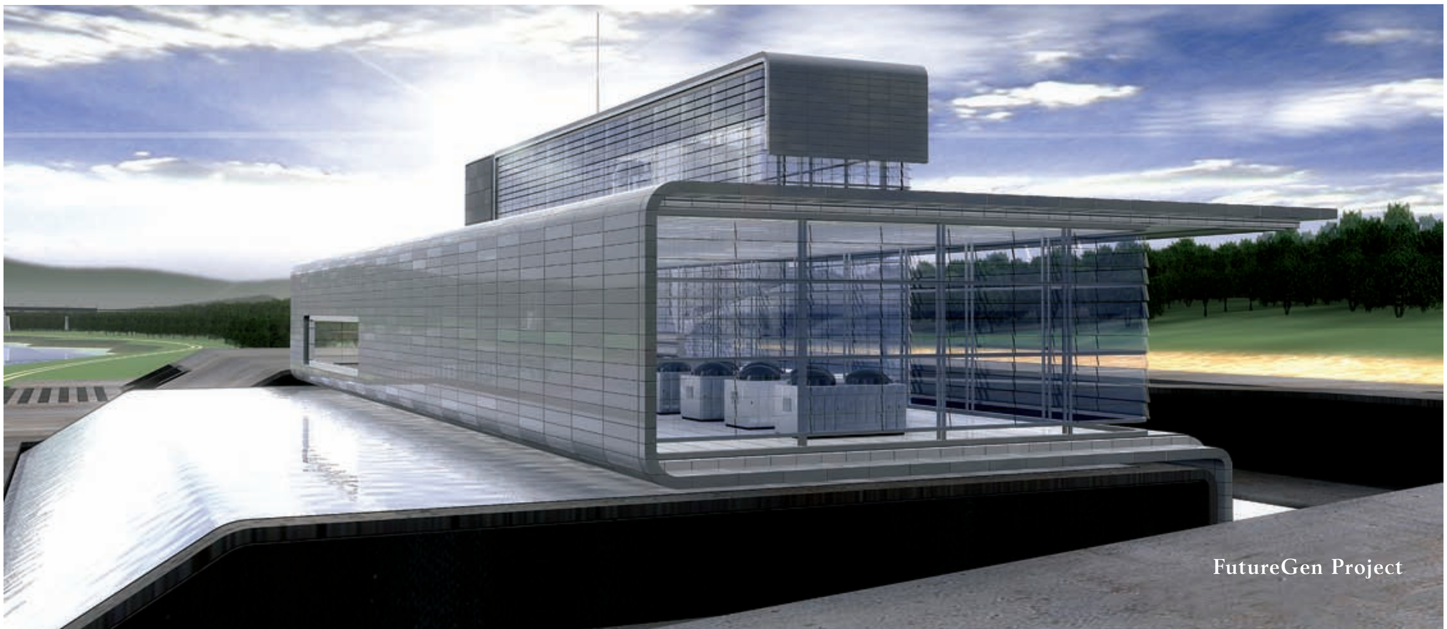
Section 2 Technologies to Reduce Carbon Dioxide

» New high-efficiency power plant designs using advanced pulverized coal combustion and gasification could reduce (compared to existing coal plants) more than 500 million metric tonnes (MMt) of CO_2 over the lifetime of those plants, even without installing a system to capture CO_2 from the exhaust gases.

» Currently available, commercially-proven technologies can significantly increase the efficiency of domestic electric power generation and thereby reduce the emission of CO_2 and regulated air pollutants such as SO_2, NO_X, mercury and particulates. Pulverized coal and gasification plants announced or beginning construction today have improved efficiencies -- about 25 percent better relative to the average of existing power plants, with correspondingly better environmental performance.

» For units already in operation, improvements in efficiency offer opportunities to reduce CO_2 emissions. Retrofits are normally undertaken to bring about efficiencies and reduce emissions, but in some cases, required upgrades to emissions equipment may use a significant amount of parasitic energy and thus offset any corresponding energy efficiency gains, possibly resulting in lower overall unit efficiencies.

» The use of coal cleaned to higher quality levels offers the potential to both reduce pollutants such as particulates, mercury, and SO_2, as well as increase efficiency.



FutureGen Project

- The U.S. generation industry will require a portfolio of highly efficient advanced clean coal technologies to provide competitive options for the range of domestic coals. Continued support of RD&D and deployment for the identified potential solutions for PC, circulating fluidized bed combustion (CFBC) and IGCC technologies to determine actual cost and reliable performance is critical to achieving low-cost, reliable and clean coal-based power.

- Continuing RD&D for advanced materials capable of handling the higher temperatures and pressures of ultra-supercritical plants is needed.

- Variances in plant designs and fuel characteristics prevent "one-size-fits all" solutions for all plants. A portfolio of clean coal technologies will be needed in the future. It is too early in the research stage to assume which technologies will be the most promising.

Section 3 Technologies for Capturing Carbon Dioxide

- Expedited demonstration of first-generation technologies for CO_2 capture is needed. Streamlining this process so the research proceeds from laboratory pilot to demonstration phase is necessary so these technologies will be available to meet future climate change regulations.

- Given the magnitude of the challenges associated with CO_2 reduction and capture, RD&D is needed on a wide range of new concepts and technologies that may provide economic solutions for carbon management.

- For advanced combustion, most opportunities for significant improvement are found in the capture process itself. For IGCC, the capture process is expected to be more efficient (compared to PC), but there are opportunities for improving the overall generation efficiency through enhanced integration between the gasification and power generation areas of the plant, better heat recovery, and through improvements in the production of oxygen in the air separation unit.

- More work should focus on demonstrating advanced technologies for CO_2 compression systems that lower the capital cost and energy requirements. Compression is expected to consume up to 8 percent of the electricity produced by a power plant and is common to nearly all CO_2 capture requirements. Improved compression systems would enhance the cost effectiveness of CO_2 capture for carbon capture systems currently being considered.

- Designers of CO_2 recovery systems should evaluate the use of waste heat recovery from the CO_2 compression systems to improve process efficiency. The effective use of the waste heat required from interstage cooling of the CO_2 during compression will improve the overall efficiency of both flue gas treatment systems for combustion-based systems and treatment of syngas for IGCC systems.

- FutureGen is a vital program and the industry looks forward to its continued development. It is such a strong model that a case can be made for a parallel program aimed at development of zero emission technologies for coal combustion plants that will also produce strong benefits domestically and internationally.

» Government has an important role in development and commercialization of energy technologies. Given the global interest in carbon capture technologies, it will be important for U.S. industries to be at the center of these important technological developments. Developing the technologies to improve efficiency and become the building blocks of tomorrow's energy systems will also enhance U.S. energy security.

Section 4 Carbon Management for Coal to Products

» Coal to products (CTP) technologies can produce a range of fuels and chemicals while generating significant amount of by-product electricity. CTP technologies can produce high quality liquid fuels, such as diesel, jet fuel, and gasoline with virtually no sulfur or particulates. Price volatility of oil and natural gas, however, is a key barrier to adoption of CTP technologies.

» Government support through Department of Defense for CTP deployment should be encouraged for the following reasons:

o To create a secure source of domestic fuel production in the event that foreign oil supply lines are disrupted, and,

o To advance the development of CTP gasification technologies which will have co-benefits in advancing essentially similar technologies for carbon capture applications at power plants.

» CTP can also produce pipeline quality natural gas that can be shipped through existing natural gas pipeline infrastructure. Producing gas from coal may avoid creating another dependency on foreign energy.

» Long-term government contracts for CTP fuels and other government-private partnerships can mitigate risk and reduce economic barriers significantly. This will help attract the capital resources needed to build and grow CTP industries.

» Co-processing biomass with coal, in combination with carbon capture and storage, may produce products that have significantly lower greenhouse gas profiles than conventional products, such as petroleum-based diesel or corn ethanol.

» The use of CCS technologies can minimize CO_2 emissions from CTP production plants and result in life-cycle greenhouse gas emissions comparable to, or lower than, conventional petroleum-derived transportation fuels.

Section 5 Carbon Dioxide Capture and Storage

Progress in geological storage of CO_2 can be accelerated through a focused program of research and development in the following areas:

» Multiple, large-scale demonstration sites for CO_2 storage in formations such as saline reservoirs are needed in the U.S. to provide sinks for initial carbon capture projects, test monitoring methods and equipment, and identify legal, regulatory and practical concerns.

» Further research is needed to gain greater insight and confidence in long-term storage mechanisms, such as solubility, capillary and mineral trapping, that increase storage security in the post-injection period; and methods must be identified for remediating storage projects that are not performing well in terms of injectivity, capacity and containment.

Key research areas include:

o Efficient methods for site characterization and selection – focusing on assessing injectivity, capacity and containment. This includes characterizing the seal, or caprock, of a storage formation over the large spatial scales needed for commercial-scale storage projects.

o Reliable methods for estimating the capacity and plume footprint (location of injected CO_2 projected on the land surface) for CO_2 stored in saline formations.

o Effective techniques for monitoring CO_2 plume migration and containment in the storage reservoir – and techniques to assess the rates and source of leakage should it occur.

o Reliable methods for assessing and mitigating the potential for abandoned wells to compromise storage integrity.

» Development of a strong base of CO_2 pipeline design standards, with consistent national approval and permitting processes to provide public confidence.

» Siting of power plants is a complex and lengthy process, integrating transmission access, ease of fuel transport, water and land use, by-product transport, etc. Successful implementation of carbon capture will add a significant additional level of complexity in siting due to the need to access acceptable storage or for pipeline to storage. It is critical that the addition of planning for CO_2 capture and sequestration does not add excessive time to the development of new generation capacity. Development of CO_2 pipelines and certification of storage sites needs to be a national priority, and should not be the sole responsibility of individual generation plant owners.

» CO_2-enhanced oil recovery, with its industry experience, and existing regulatory protocols, provide an important commercial path for CO_2 storage, and a bridge to utilizing formations, such as saline reservoirs, that hold the largest potential for CO_2 storage.

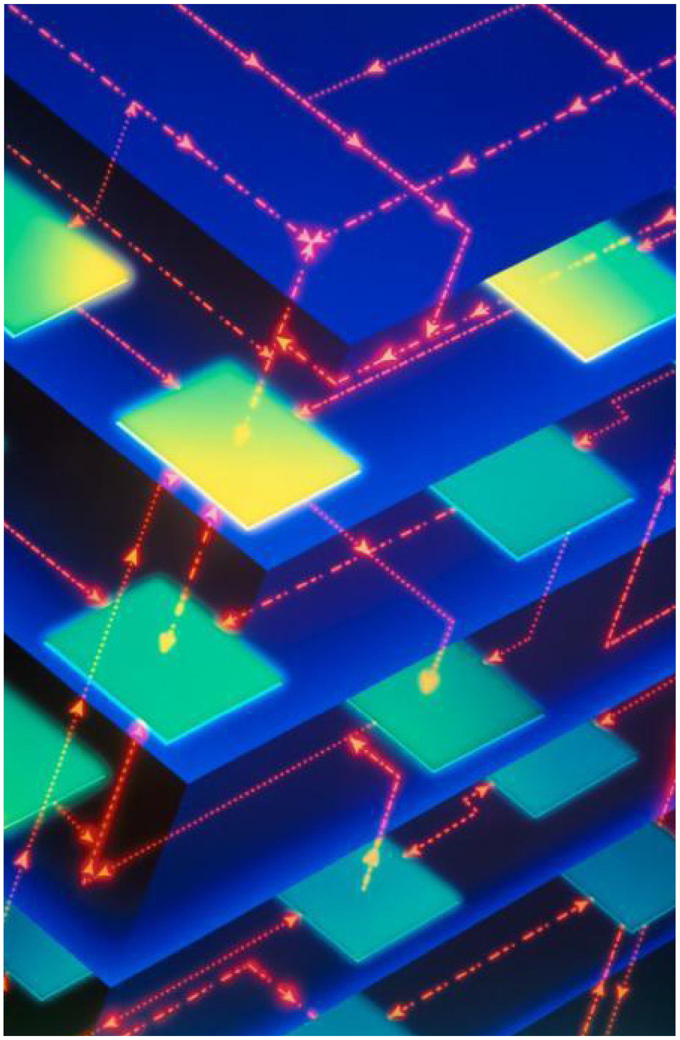
» Carbon capture and geologic sequestration will create potential long-term liabilities. Implementation of CCS would be in response to anticipated or existing government imposed limits on CO_2 emissions; therefore, these liabilities should not be imposed on the electric generators or coal producers. As such activities are done to serve the public good as determined by the government, the entities performing those activities should be provided a large measure of long-term risk reduction.

» Deployment of agricultural management, forestry practices and wetland restoration for terrestrial carbon sequestration to reduce the rate of accumulation of CO_2 in the atmosphere while restoring degraded soils, enhancing biomass production and generating environmental co-benefits (e.g., improved water quality, biodiversity protection, land conservation, erosion reduction, etc.).

» The nation should pursue all avenues of reducing CO_2, including further research into finding beneficial uses of carbon dioxide such as to spur algae growth and create biofuels.

Section 6 Technology Profiles and Trends

» Analysis of the current state of CCS technology provides optimism that necessary advances can be made to meet goals for CO_2 capture and sequestration, but also emphasizes that success will require a stronger and more concerted and collaborative effort than is currently under way.



» Achieving greenhouse gas emissions reduction goals will require a broad suite of advanced coal and CCS technologies that can be tailored to the conditions of each individual geographic location, electricity market structure, fuel source, etc.

» **IGCC.** RD&D plans for IGCC with CO_2 capture provide a pathway toward realization of a roughly 30 percent reduction in the capital cost over the next 20 years on a constant dollar basis, while increasing net efficiency by 9 percentage points.

o The CO_2 capture process for gasification is considered commercially mature since it uses technologies that chemical industries have already developed for acid gas cleanup in coal- and petroleum-based gasification systems and in natural gas processing. However, using those technologies at large scale in IGCC power plants still constitutes a first-generation application. The technology has not been completely and efficiently integrated into a large-scale power plant and CCS system. Furthermore, hydrogen turbines have not yet been demonstrated in commercial-scale IGCC applications.

o The base IGCC technology is commercially available, but will benefit significantly from an accelerated RD&D effort to achieve efficiency, reliability and availability improvements, which also are required to meet the CURC-EPRI[6] targets for pre-capture systems. Additional efforts will focus on adapting combustion turbines for use with hydrogen-rich fuels and on cost-effective integration.

» **Pulverized Coal.** Current RD&D plans for advanced PC generation with CO_2 capture provide a pathway toward realizing a 30 percent reduction in the capital cost over the next 20 years on a constant dollar basis, while increasing net efficiency by 12 percentage points.

o For PC and CFBC technology with CO_2 capture, significant cost and performance improvements will need to come from work to improve energy-consuming solvent processes that separate carbon from exhaust streams. Current processes have high capital costs and high auxiliary power or steam demand.

[6] Coal Utilization Research Council (CURC) and Electric Power Research Institute (EPRI).

o Significant CO_2 management gains and cost reductions can also be achieved by improving the efficiency of the generation system with ultra-supercritical pulverized coal combustion and supercritical circulating fluidized bed combustion technology.

» Regardless of the technology, experience teaches us that early in the development of new technologies, we often underestimate the costs and construction lead times for initial full-scale projects. Although engineering-economic studies of advanced coal and CCS technologies attempt to allow for this phenomenon, initial full-scale applications may prove to be more costly than expected. Eventually, accumulation of lessons-learned will bring substantial improvements in performance, reliability and cost.

» For many of these technologies, timely attainment of the desired developments will require significant public policy and funding support to enable collaborative initiatives involving power producers, equipment manufacturers, government agencies, academic research organizations and others. Key elements include:

o predictable policies,

o sharing of cost and schedule risks, and

o accelerated publication and incorporation of lessons learned.

Section 7 Groups Engaged in Technology Development

» While funding for CO_2 capture and storage research has accelerated in recent years, it is insufficient to advance the commercialization of the technology at an acceptable pace, particularly for large-scale stand-alone and integrated CCS demonstrations and for deployment of the technology.

» Public/private partnerships work – the U.S. needs to accelerate these efforts.

» The DOE National Energy Technology Laboratory (NETL) regional carbon sequestration partnerships are initiatives that are already in progress and advancing knowledge surrounding carbon sequestration technology.

Section 8 Energy Policy Act of 2005 – Key Coal Provisions

» Given the early stage of development of technologies for carbon capture, compression, delivery, storage and monitoring, as well as the known track record needed to bring such technologies to maturity in the market, the National Coal Council recommends that DOE continue to support the many programs outlined throughout this report. As technologies mature, it will be even more important for DOE to support deployment of new technologies using all the tools at its disposal, such as financial incentives and favorable tax policies.

» Also, because limited data exist for IGCC units operating on low rank coals, the Energy Policy Act of (EPACT) of 2005 encouraged increased investment in RD&D of IGCC plants using these coals to provide more accurate data on costs and performance. Given the growing importance of lower rank coals in U.S. electricity generation, this research should be continued for a range of gasification technologies, including slurry and dry feed gasifiers.

NCC RECOMMENDATIONS

The National Coal Council makes the following recommendations in the belief that the U.S. Congress will address carbon management in the near future. In that context, it is imperative that the nation immediately accelerate deployment of technologically and economically favorable high-efficiency advanced coal combustion, coal liquefaction and gasification technologies. In addition, it is critical to accelerate development, demonstration and deployment of CO_2 reduction and CCS technologies to control and sequester CO_2 emissions from these advanced coal-based technologies. These technologies will be implemented as they become available, affordable and deployable.

Therefore, the National Coal Council recommends that the Department of Energy, acting in coordination with other federal agencies and states, should:

» Work closely with other appropriate agencies within the federal government to streamline the long, costly and complicated permitting process for siting, building and operating power plants and associated CO_2 capture, transportation and storage facilities.

o The EPA's New Source Review (NSR) regulations can impede retrofit applications at existing facilities and thus may block efficiency improvements and corresponding CO_2 benefits. A cooperative approach between DOE and EPA to facilitate the implementation of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) regulations, for example, would be extremely helpful.

– Ideally, reconciliation of all these programs into one clear and workable set of regulations would be very positive.

– EPA rules for implementing CAIR and CAMR should align with NSR regulations so that as existing power plants come into compliance with these rules, they are given incentives to simultaneously make efficiency improvements in plant operations.

» Significantly ramp up RD&D funding across the full spectrum of CCS technologies (capture, compression, transportation, storage and monitoring) so as to ensure that the U.S. can meet industry, state and national expectations for capture and storage of CO_2.

» Continue to fund and support these activities within the regional carbon sequestration partnerships:

o Create a team led by a senior member of DOE management to lead an engineering program for testing multiple CCS technologies at power plant scale within the next five years.

o Determine the legal liabilities associated with CCS. This includes resolving ownership issues and responsibility for stored CO_2 in the event of leakage, and implementing long-term monitoring of storage facilities.

o Increase funding of regional partnerships to adequately finance large-scale CO_2 storage projects in a number of different geologic formations, such as deep saline reservoirs and enhanced coal bed methane recovery. Current projects are focused strongly on enhanced oil recovery applications which enable a lower total cost, but further work needs to be done to prove the viability of other kinds of projects so as to represent a spectrum of geology in areas where CO_2 is generated.

» Support RD&D projects that cover a wide variety of capture technologies, including those that capture less than 90 percent of the CO_2, because of the early stage in the technology maturation process. CO_2 capture rates will increase as the technology matures, and the nation should not abandon technologies today simply because they cannot immediately meet high CO_2 capture expectations early in the development cycle.

» Pursue a large scale demonstration project to spur development of advanced ultra-supercritical pulverized coal power generation. Extremely high temperatures and pressures (1,400°F, 5,000 psi) are required to achieve high plant efficiency, which require the development of new alloys and components. Because of the cost premium necessary to develop new materials, financial support will be needed initially to demonstrate that this kind of advanced design is viable.

» Promote significant additional research and demonstration projects related to the transportation and safe storage of CO_2 by coordinating with other federal agencies to:

o Develop accepted performance standards or prescriptive design standards for the permanent geological storage of CO_2.

o Foster the creation of uniform regulatory guidelines site selection, operations, monitoring and closure for storage facilities.

o Ensure creation of a federal entity to take title to and responsibility for long-term post-closure monitoring of underground storage, liability and remediation at all CO_2 storage sites.

o Facilitate development of an economic, efficient and adequate infrastructure for transportation and storage of captured CO_2.

o Create a legal framework to indemnify all entities that safely capture, transport and store CO_2, regardless of their size, and develop realistic initial expectations for CO_2 monitoring, measurement and verification.

o Create clear transportation and storage rules that provide incentives to business models that will encourage the development of independent collection pipelines and storage facilities. Such rules must expedite the growth of independent businesses with a singular focus on CO_2 transportation and storage, rather than power plant operations.

» Consider undertaking three to five projects (at both pulverized coal and IGCC plants) at a scale of about 1 million tonnes/year of CO_2 injection to understand the outstanding technical questions and to demonstrate to the public that long term storage of CO_2 can be achieved safely and effectively.

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- Large and small coal producers
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- Rail, waterways, and trucking industries, as well as port authorities
- Academia
- Research organizations
- Industrial equipment manufacturers
- State government, including governors, lieutenant governors, legislators, and public utility commissioners
- Consumer groups, including special women's organizations
- Consultants from scientific, technical, general business, and financial specialty areas
- Attorneys
- State and regional special interest groups
- Native American tribes

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“Energy and persistence conquer all things”
— Benjamin Franklin

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SECTION ONE

World Energy and Greenhouse Gas (GHG) Emissions Context

FINDINGS

- Energy consumption is driven by economic expansion and population growth. Both are projected to increase substantially by 2030 – especially in China and India, the world's two most populous countries.
- As all nations seek to improve the quality of life, by 2030 electricity consumption will increase over 100 percent at the global level and by more than 50 percent in the United States. In the latter, the North American Reliability Council (NERC) has identified the "addition of power generation facilities" as first on a list of 22 necessary actions to meet electricity reliability requirements.[1]
- Meeting the world's energy needs will require a portfolio of solutions, including energy efficiency gains, additional renewables, new nuclear power capacity and significant new coal-based generation.
- Coal will remain a low-cost option for generating electricity for years to come and should become increasingly viable as a substitute for liquid fuels and natural gas. Worldwide, coal is abundant, secure, versatile and increasingly clean.
- Accordingly, coal will be the continuing foundation of electricity supply – meeting 40 percent of global demand in 2030 and 58 percent in the U.S.
- If the projections of oil and natural gas production through 2030 fall short or are affected politically, demand for coal will increase even further.
- The U.S. is leading the developed industrialized world in reductions in carbon intensity. The U.S. electric utility industry has already made considerable progress in providing reliable and affordable electricity that involves increasingly lower carbon emissions per unit of production.
- Given the explosive growth in Asian energy demand and carbon emissions, the incremental effects of unilateral reductions in carbon emissions made by the U.S. and other nations may be overwhelmed several times over unless those nations also adopt carbon management strategies.

THE GLOBAL CONTEXT---The Rising Tide of Energy Demand

An adequate and affordable supply of energy is the foundation of both economic growth and a higher quality of life. In a world where over **1.6 billion people** do not have access to electricity, China, India and other developing nations recognize this reality – and are aggressively investing in energy supplies to sustain and extend their progress on economic development. Indeed, across the globe all societies – mature, transitional and emerging – are striving to meet the rising expectations of their populace for ever increasing amounts of electricity, liquid fuels and natural gas. In fact, the constant struggle to produce more and more energy eventually may be the defining economic backdrop of the first half of this century. Thus, there appears to be little doubt that the search for new energy sources will be more competitive, take us further afield and be more expensive than ever before.

Over the period 2003 – 2030, world population will grow from 6.3 billion to 8.2 billion – an increase of 30 percent. This addition of almost 2 billion people equals the **combined** current population of all of Africa, North America, South America and Europe. China and India alone will account for over one-fourth of global population growth. And the United States, a post industrial nation, will grow by almost 75 million people – 25 percent.

Even more dramatically, from 2003 to 2030, World Gross Domestic Product is expected to grow in real terms from $51 trillion to $140 trillion – an increase of 175 percent. China's economy will grow by 380 percent, India's by 311 percent and the U.S. by 129 percent.[2]

These surges in population and economic growth, coupled with the rising expectation of a better life, will stimulate an unprecedented increase in demand for energy. World energy consumption is projected to increase from 420 quadrillion Btu in 2003 to 722 quadrillion Btu in 2030 – an increase of 72 percent. This additional demand is equal to the **combined** current consumption of all of Africa, North America, South America and Europe, **plus** Japan and China.

This increase in energy demand will have at least two distinguishing characteristics: (1) three nations – China, India and the United States – will account for half (49 percent) of the world's incremental energy consumption. And (2), the three primary fossil fuels – oil, natural gas and coal – met 86 percent of consumption in 2003 and will continue to meet 87 percent in 2030.

Nation	Energy Consumption 2004 – 2030 (Quadrillion Btu)		
	2003	2030	% Increase
U.S.	98	134	37
India	14	33	136
China	46	139	202
Rest of World	263	416	58

Figure 1-1: Regional Energy Consumption, 2004-2030
Data Source: U.S. Energy Information Administration, International Energy Outlook

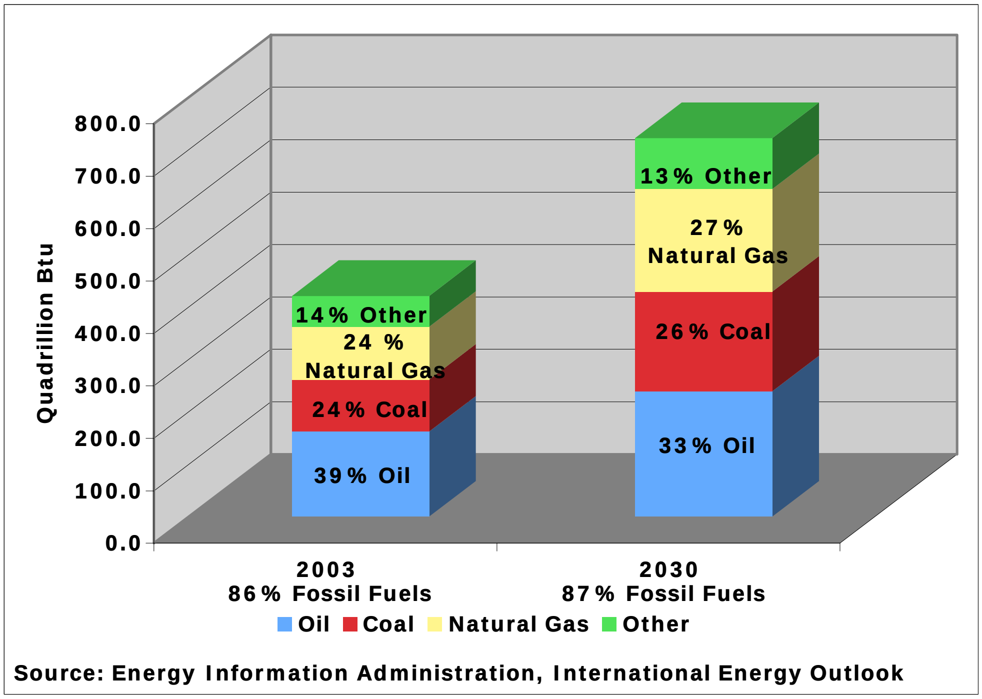


Figure 1-2: Fossil Fuels as the Continuing Core of Energy Supply

Electricity Consumption Will Double by 2030

Electricity is the lifeblood of modern society. As ever increasing billions of people strive to improve their quality of life, electricity consumption is projected to grow apace. World net electricity generation, for example, is projected to grow from 14,885 billion kWh in 2003 to 31,560 billion kWh in 2030 – an increase of 112 percent. While electric generation will grow across the world, absolute growth will be particularly concentrated in several of the largest consuming nations/regions. As Figure 1-3 shows, four areas will account for 55 percent of the global increase in electricity generation:

Nation/Region	(Billion kWh)	
	Increase (Billion kWh)	% of Global Incremental Generation
U.S.	1,777	11
China	4,654	28
Europe (OECD)	1,375	8
India	1,338	8

Figure 1-3: Increase in Net Electricity Generation, 2003 – 2030
Data Source: U.S. Energy Information Administration, International Energy Outlook

Coal as the Continuing Foundation of Electricity Supply

In 2003, coal generated 41 percent of the world's electricity. By 2030, coal will generate 40 percent. In terms of absolute numbers, coal generated 6,160 billion kWh in 2003 and by 2030 will generate 12,592 billion kWh.

Coal-based generation will be a major component of electricity supply in many countries, but three nations – China, the U.S. and India – will account for 90 percent of the global increase in coal-based generation:

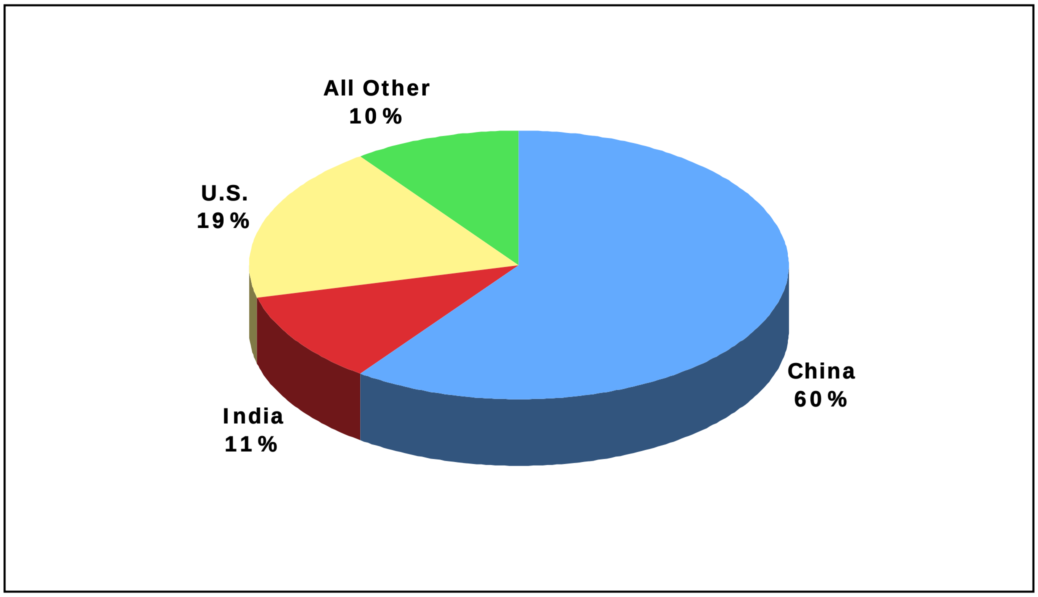


Figure 1-4: Incremental Increase in Global Coal-Based Generation[3]
Data Source: U.S. Energy Information Administration, International Energy Outlook

Given their respective energy reserves, it is certainly not surprising that these three nations will increasingly turn to coal as a reliable source of electricity.

Nation	Percent of Global Energy Reserves		
	Oil	Natural Gas	Coal
U.S.	2	3	28
India	< 1	< 1	10
China	1	1	13

Figure 1-5: Global Energy Reserves
Data Source: U.S. Energy Information Administration, International Energy Outlook

Increase

In 2003, the world used 5.4 billion tons of coal, but by 2030 usage will reach over 10.5 billion tons – an increase of 95 percent. China will account for 60 percent of the global increase in coal consumption through 2030.

Availability, reliability and affordability are important determinants in this broad reliance on coal-based electricity. Further, other nations are preparing to adopt clean coal technologies developed in the U.S.

In China, for example, a major analysis published by the Chinese Academy of Social Science in July 2006 concluded:

> *"Advanced combustion power generation technology, developed by the United States, would increase efficiency and lower the volume of sulfur dioxide and soot emission to one tenth of the standard."*
> Energy Development Report of China

This continuing reliance on coal to meet rising electricity demand will significantly increase coal consumption. In 2003, the world used 5.4 billion tons of coal, but by 2030 usage will reach over 10.5 billion tons – an increase of 95 percent. China will account for 60 percent of the global increase in coal consumption through 2030.

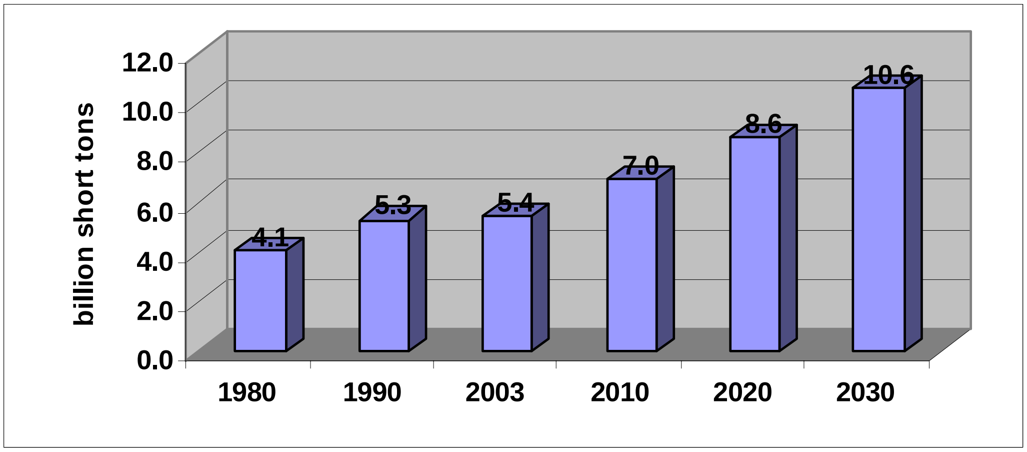


Figure 1-6: World Coal Consumption
Data Source: U.S. Energy Information Administration, International Energy Outlook

Coal's Crucial Role in U.S. Generation

In the United States, coal has been the workhorse of power generation for decades. Electricity consumption in the U.S. is projected to grow 53 percent through 2030 and coal-based generation will continue to be the cornerstone of U.S. supply:

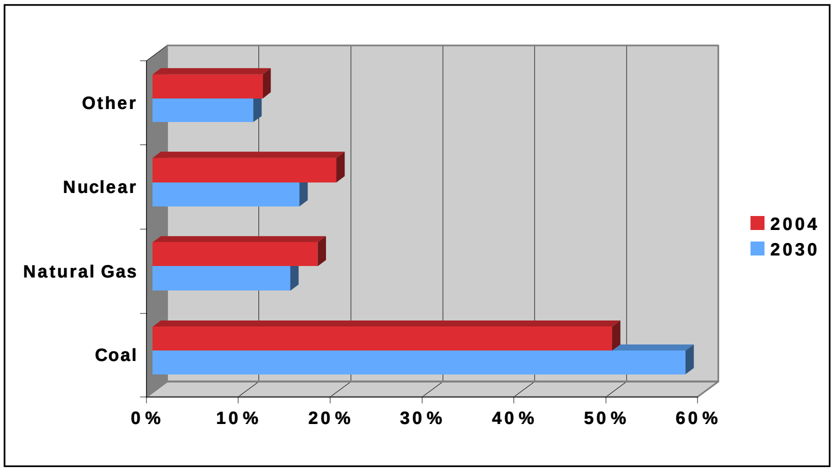


Figure 1-7: Coal as the Continuing Core of Electricity[4]

A new wave of coal-based power plants has been proposed:

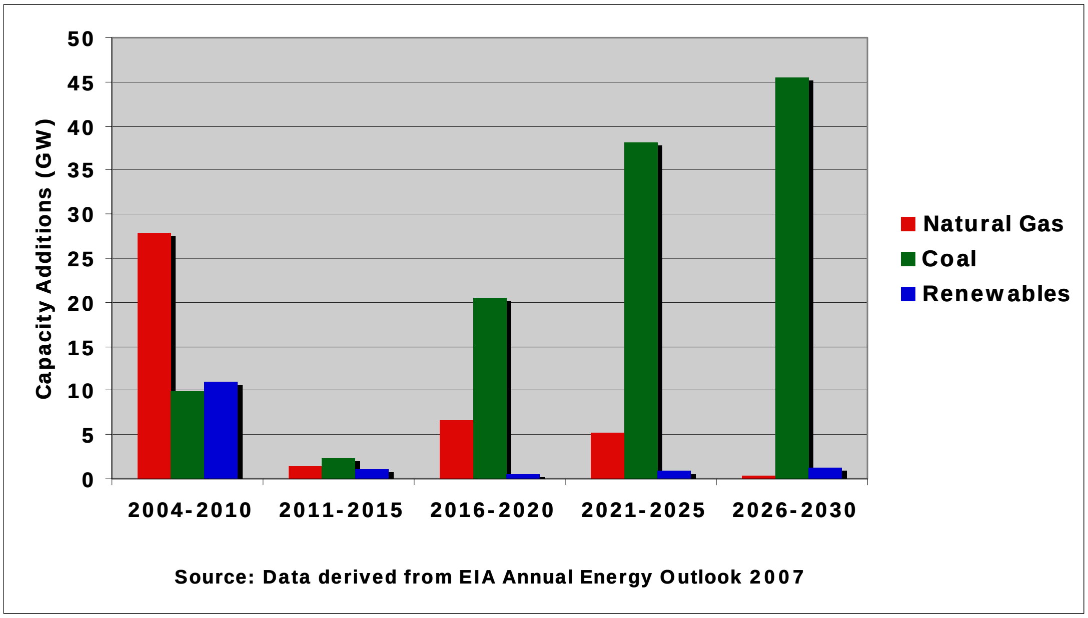


Figure 1-8: U.S. Forecasts Largest Coal Generation Capacity Growth in 40 Years

Implications for Coal Worldwide

As China and other developing nations (e.g., India) become major players on the world's energy stage, the impact on the U.S., Japan and Europe will be profound. And the consequences for coal could be far-reaching.

Most government-based forecasts in the energy importing nations paint a relatively optimistic view of global oil and natural gas production. If these projections are not met, however, coal will be required to pick up the slack through both liquefaction and gasification.

By 2030, the world will need an additional 300 quadrillion Btu of energy – three times current U.S. consumption. The U.S. Energy Information Administration (EIA) projects that oil will meet 26 percent of that new demand and natural gas 30 percent. In raw numbers, that would be increases of 38 mmb/d (million barrels per day) of oil and 87 tcf (trillion cubic feet) per year of natural gas. In regard to natural gas, for example, the world will have added over 1,000 gigawatts (GW) of natural gas generating capacity – a 100 percent increase in less than three decades.

Challenge

The world will need to increase oil production each year by more than 7 million barrels per day to merely offset depletion and eke out a 1 mmb/d net gain in production capacity – the equivalent of a new Iran plus Norway every year.

While a wide range of questions can be posed about these very optimistic projections, three issues immediately come to mind: Depletion rates, natural gas production and Europe's impact.

- Oil depletion rates. Oil wells, as they mature, decline in production and are eventually depleted. The loss of production must be replaced from other wells. For example, for the world to increase conventional oil production from current levels of roughly 80 mmb/d to the 106 mmb/d predicted by EIA for 2030, world petroleum companies actually must bring more than 6 mmb/d of new production on-line each year to offset depletion of roughly 5 mmb/d. The chart below illustrates the precarious treadmill of world oil production:

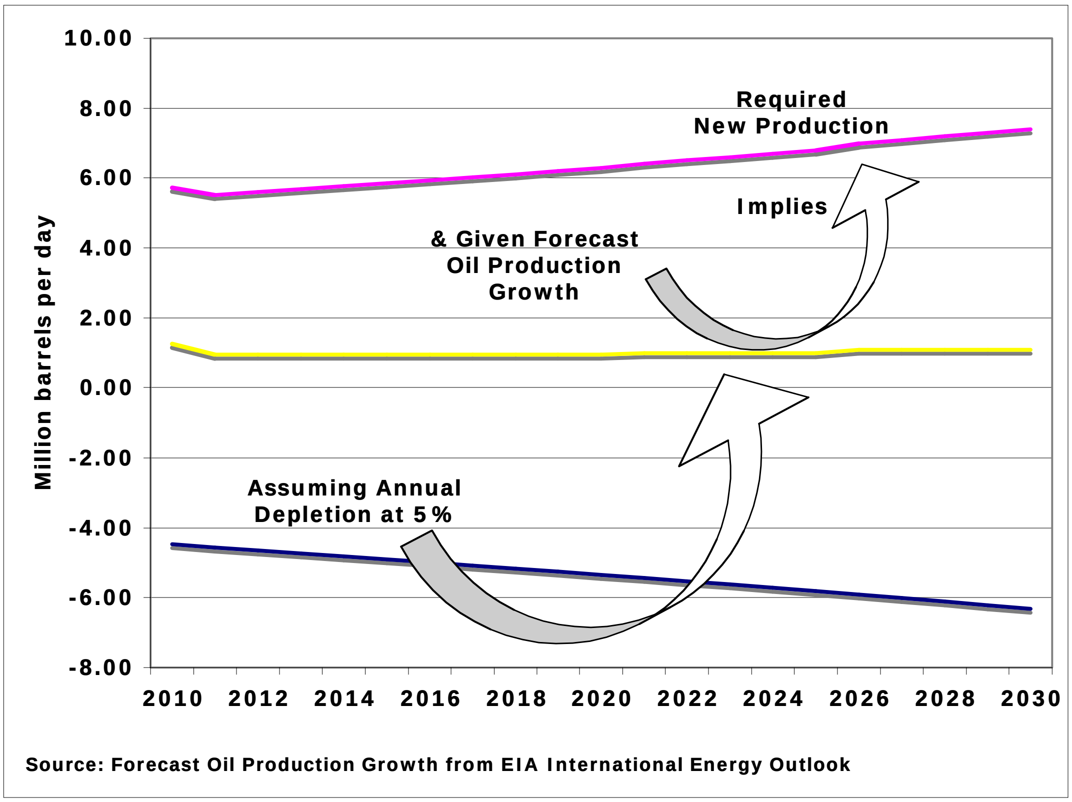


Figure 1-9: New Production to Offset Depletion
and Achieve EIA's Conventional Oil Production Forecast

Assuming current depletion rates increase from 5 percent today to 6 percent by 2030, the world will need to increase production each year by more than 7 million barrels per day to merely offset depletion and eke out a 1 mmb/d net gain in production capacity – the equivalent of a new Iran plus Norway every year. If this new production does not materialize, the widely feared peak in conventional oil production will become a reality. Indeed, the EIA long-term forecast predicts more than 11 mmb/d of unconventional oil production, including coal to liquids, heavy oil, tar sands, shale and other sources. Rising production of unconventional resources is an early indicator of a peak in low-cost conventional oil production.

- Natural gas production will have to increase 90 percent at the global level to meet projected demand. Can Russia increase gas production by 90 percent by 2030? India by 140 percent? The Middle East by 188 percent? Africa by 263 percent?

China by 266 percent? Given the gas-dependent infrastructure being built across the globe, the economic destiny of entire societies will be affected by the answers.

Any significant escalation in price will disproportionately affect the developing nations. The winter of 2006 demonstrated that countries such as Spain and France will bid up prices to attract incremental shipments of liquefied natural gas (LNG). In essence, China, India and other developing nations may be priced out of the global LNG market and forced to expand their use of coal even beyond current plans. In essence, the price for natural gas on the global LNG market may increase to a point where all countries will be forced to expand their use of coal beyond current projections. The consequences for coal would be substantial. For example, what if the increase in installed natural gas capacity (1,000 GW) is not built or cannot obtain fuel? Generators worldwide will surely turn to coal to meet the demand for power.

Further, the EIA also substantially increased its projection of coal consumption in just one year. In the International Energy Outlook (IEO-2005), the EIA projected global consumption would be 8,226 tons in 2025. In the IEO-2006, however, EIA projected coal consumption would reach 9,558 tons – an increase of 16 percent in only 12 months.

Will OECD[5] Europe Upset the Natural Gas/Liquefied Natural Gas (LNG) Balance?

Natural gas is rapidly becoming a global commodity. The increasing dependence of European countries, (especially those that form the Organisation for Economic Cooperation & Development) on gas pipeline and LNG imports will shape the market worldwide.

- Natural gas accounts for 23 percent of Europe's energy consumption, but by 2030 that dependence will grow to over 33 percent.
- Natural gas consumption is projected to grow from 18 tcf to 31 tcf by 2030 – a 72 percent increase.
- Europe is projected to add 160 GW of natural gas generating capacity by 2030
- Europe's production of gas is projected by EIA to decline from 10.7 tcf to 10.3 by 2030. Yet, North Sea gas for the U.K. reached a 14 percent decline year-over-year in 2006, making it very likely Europe will see a greater rate of decline.
- Even based on EIA's optimistic projections, Europe will need to import 20 tcf by 2030 – more than the total production of the United States.
- Europe will be increasingly dependent on Russia – a nation which announced in 2006 that it was planning to send at least 30 percent of its natural gas and oil to Asia within the next decade.

Trade-Off Between Gas and Coal

Figure 1-10 estimates the additional coal that may be required to substitute for lower than projected increases in natural gas power generation. The context of this graph is that by 2030 natural gas-based electric generation is projected to increase 242 percent. The following graph depicts the additional coal required to meet electricity demand if the EIA IEO projection that global natural gas-based generation will increase 242 percent by 2030 is not met.

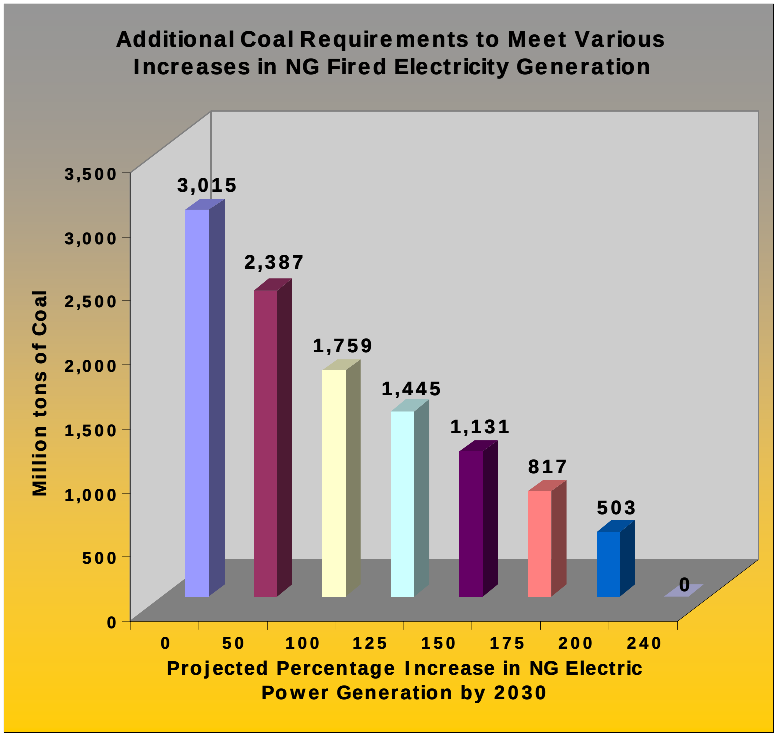


Figure 1-10: Potential World Need for Coal Based On Amount of Increase in Natural Gas Generation

Figure 1-10 demonstrates a shortfall in natural gas supply will have far reaching consequences for coal. In fact, the major energy agencies are steadily moving in this direction. In the 2006 World Energy Outlook (WEO), the IEA increased the projection of coal demand significantly:

> *"Coal use rises by 32 percent by 2015 and 59 percent by 2030 - a significantly faster rate of growth than in the WEO-2005 . . .gas grows less quickly than in the last Outlook."*

Carbon Dioxide and Greenhouse Gas Emissions

Economic growth requires the production and consumption of energy, which creates inevitable byproducts such as greenhouse gas (GHG) emissions, including carbon dioxide (CO_2). This section explores these issues by examining carbon emissions by region and sector. A comparative analysis of carbon intensity across various countries is also presented. U.S. progress on carbon management, which to date has generally been market based, will be compared with progress in countries committed to carbon reductions under the Kyoto Protocol. This comparison reveals that most of these countries have failed to meet their carbon emission reduction targets. And although the U.S. also has increased CO_2 emissions, the U.S. continues to make progress when CO_2 emissions are measured relative to its economic output, resulting in steadily declining carbon intensity.

Another important lesson and somewhat sobering reality is that attaining absolute reductions in carbon emissions while maintaining economic growth is extremely difficult. While societies around the world will continue to reduce carbon intensity, the rising tide of energy consumption caused by higher economic growth will continue to offset the emission reductions. The only way off this treadmill is technological innovation, which is why current policies that support a flexible, technology-based approach toward carbon management are most likely to achieve long-term results at the least cost to society. Technology transfer, for example, has great promise for reducing future increases in GHG emissions in developing countries – the projected source of most emission growth.

Technology-based Policies

Policies that support a flexible, technology-based approach toward carbon management are most likely to achieve long-term results at the least cost to society. Technology transfer, for example, has great promise for reducing future increases in GHG emissions in developing countries – the projected source of most emission growth.

Man-made Sources of World Greenhouse Gas Emissions

More than 35 percent of man-made emissions come from non-energy-related sources, such as deforestation, emissions from livestock and soils, and emissions from landfills and other waste repositories (See Figure 1-11).

Other

More than 35 percent of man-made emissions come from non-energy-related sources.

The remaining 65 percent of man-made emissions is from five major categories related to energy production and use: electricity and heat (24.6 percent), industry and industrial processes (13.8 percent), transportation (13.5 percent), other fuel combustion (9 percent) and fugitive emissions (3.9 percent). Carbon dioxide is emitted throughout the industrial supply chain from the combustion of fuels to generate heat and electric power, to metals and cement production, to food processing and many other diverse applications.

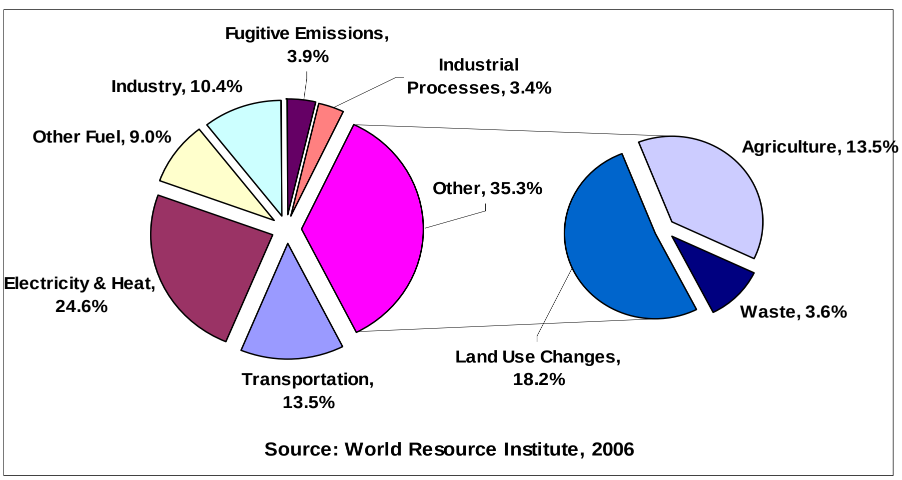


Figure 1-11: World Greenhouse Gas Man-made Emissions by Source, 2000

The EIA projects that world energy-related carbon dioxide emissions will grow at an average annual rate of 2.1 percent from 2003 to 2030. U.S. carbon emissions are expected to increase 1.3 percent per year while annual emissions from other Organisation for Economic Cooperation & Development (OECD) countries are predicted to rise on average 0.9 percent. In contrast, carbon emissions from non-OECD countries will grow more than twice as fast, averaging 3.0 percent annually. China's emissions of greenhouse gases are expected to ***triple*** over the same period, rising at more than 4.2 percent per year. The non-OECD Asia region, which includes China, India and other fast growing Asian economies, will soon have the largest GHG emissions in the world. According to the EIA forecast, by 2030 emissions from this region are expected to be more than 30 percent higher than greenhouse emissions in the U.S. More than 40 percent of global carbon emissions expected over the next 30 years will come from China (see Figure 1-13).

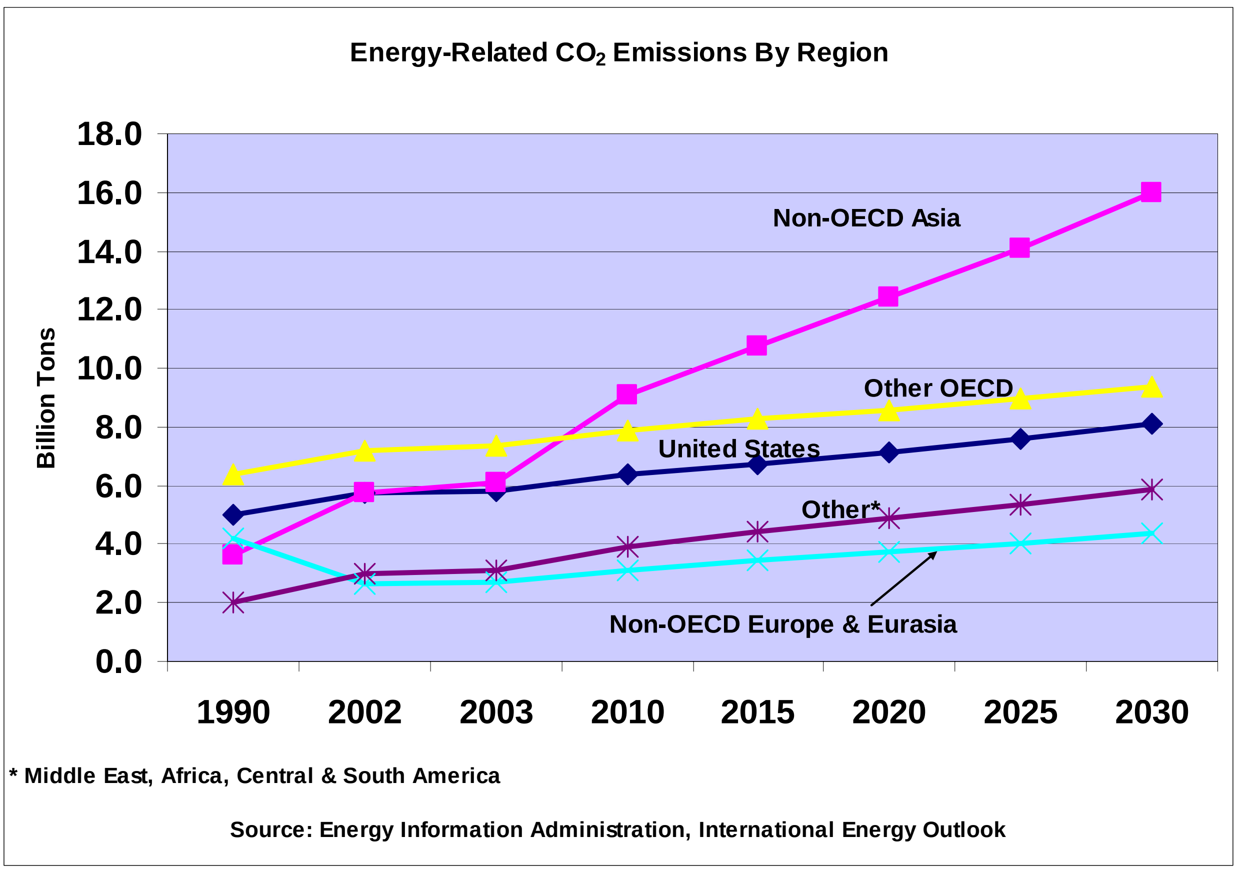


Figure 1-12: Energy-Related CO_2 Emissions by Region 1990-2030

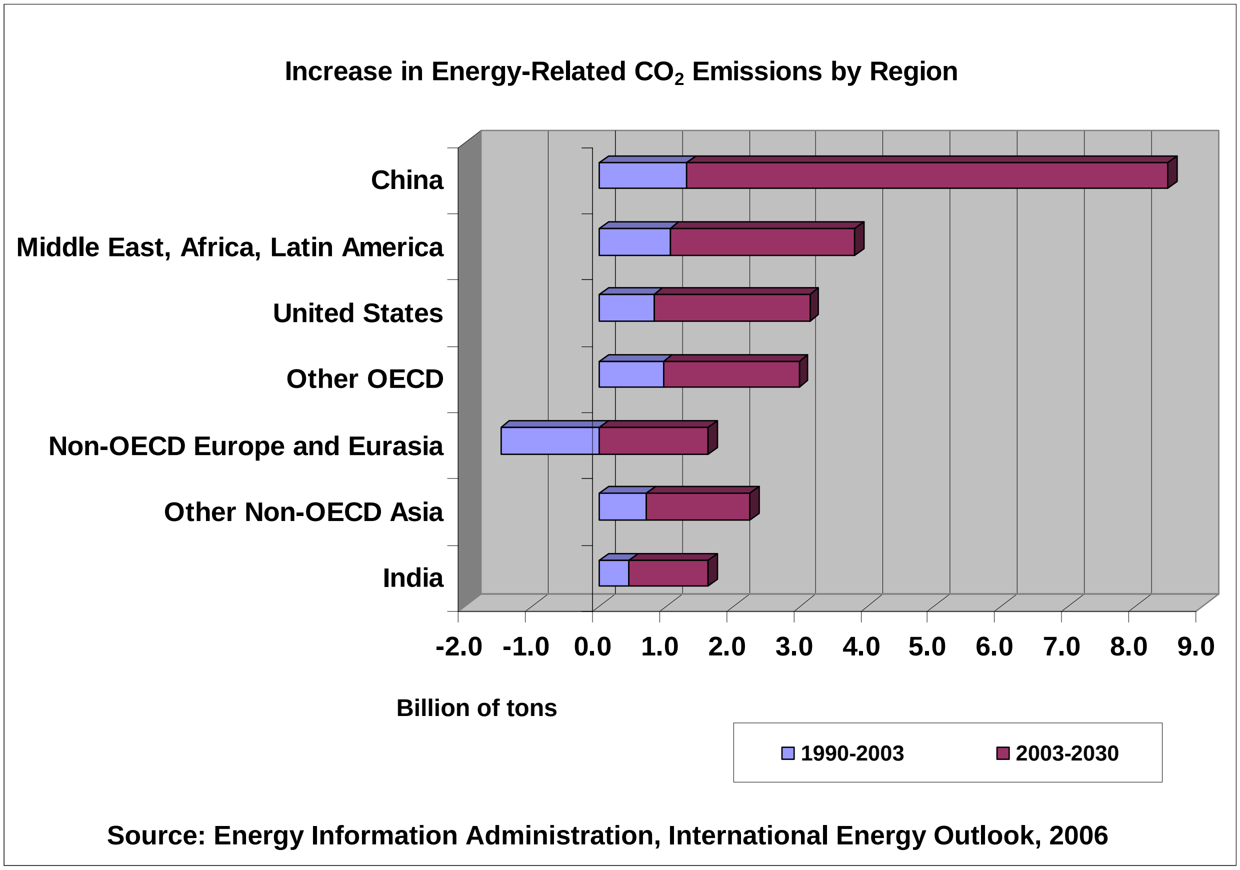


Figure 1-13: Increase in Energy-Related CO_2 Emissions by Region

Economic and Population Growth Drive Carbon Emissions

These large regional disparities in greenhouse gas emission trends exist because economic growth in non-OECD countries is projected to substantially exceed growth in the U.S. and other OECD economies. Figure 1-14 below compares gross domestic product in purchasing power parity and greenhouse gas emissions in the U.S. and China. The analysis illustrates the strong positive correlation between economic growth and greenhouse gas emissions. China's economy will become larger than the U.S. economy sometime between 2020 and 2025. China's greenhouse gas emissions will exceed U.S. levels even earlier because their economy is in the stage of development that entails construction of infrastructure requiring energy-intensive materials, such as steel and cement. In fact, the IEA recently indicated China would likely surpass the U.S. in CO_2 emissions by 2009 – about a decade ahead of earlier expectations. Further, such emissions would be even higher were it not for reductions in the amount of carbon emissions per unit of gross domestic product (GDP).

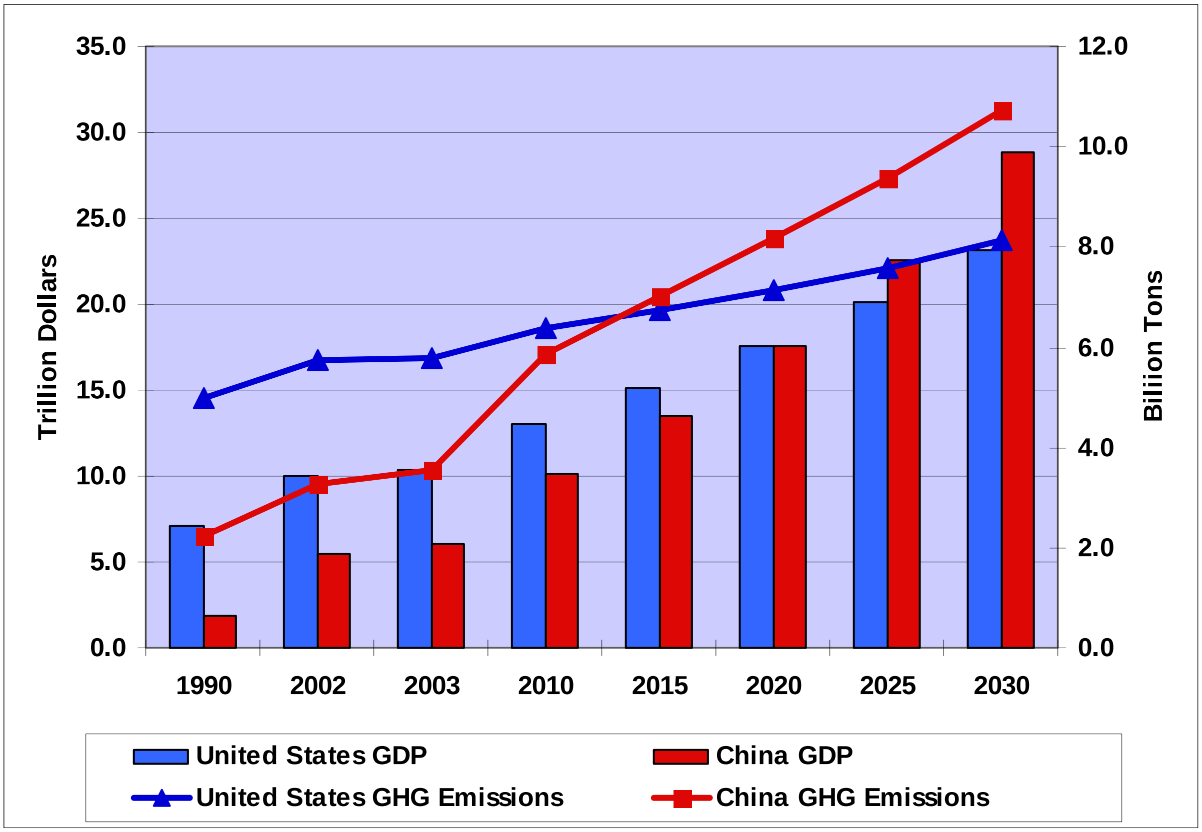


Figure 1-14: Gross Domestic Product and Greenhouse Gas Emissions in the United States and China, 1990-2030

Data Source: U.S. Energy Information Administration, International Energy Outlook

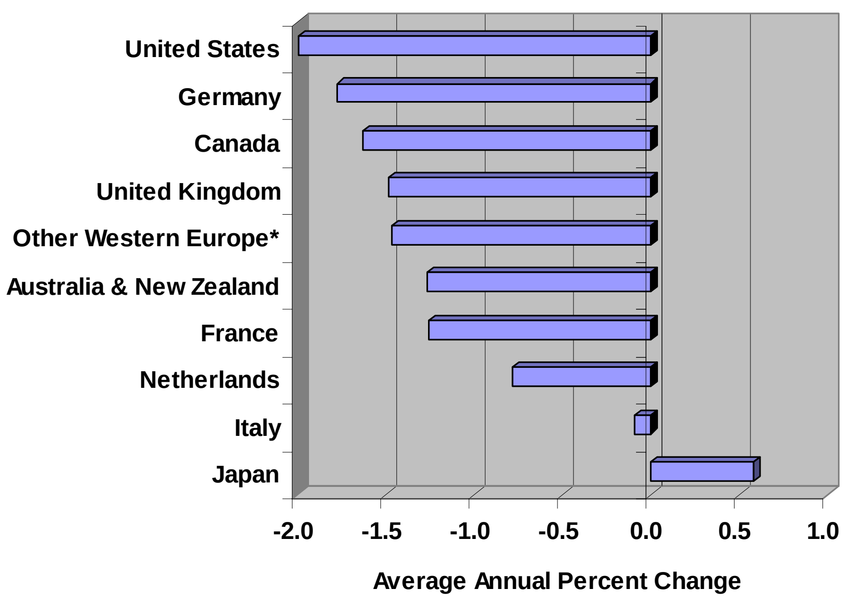
Carbon Intensity Worldwide

The U.S. electric utility industry has already made considerable progress in providing society with reliable and affordable electricity that involves increasingly lower carbon emissions per unit of production. This improvement in carbon intensity will continue and likely accelerate as new technologies are adopted. A strong argument can be made that a technology-based approach to carbon management and the accompanying technological innovations will continue to achieve significant results. For example, the power industry reported 282 million metric tonnes of carbon equivalent emission reductions, avoidances and sequestrations during 2004, representing 63 percent of all such emission reductions reported to the federal government.[6] Further, the Energy Policy Act of 2005 includes a range of technology-related provisions that, with robust budget support and implementation, could facilitate wider adoption of carbon management initiatives.

The United States continues to reduce carbon intensity while maintaining one of the fastest-growing, wealth-generating economies in the world. Mature market economies, however, cannot shoulder the burden of carbon management alone. As Raymond Kopp from Resources for the Future has pointed out:

"It matters little what the European Union, the United States, and the rest of the world do if we cannot entice the developing world – countries like China, India and Brazil – to reduce emissions as well." [7]

The U.S. has been making considerable progress on reducing its carbon intensity, or the amount of greenhouse gas emissions per unit of GDP. Among the most developed nations, the U.S. leads in carbon intensity improvements, reducing it on average 2 percent per year from 1994 to 2004 (see Figure 1-15). In contrast, the Japanese economy actually increased its carbon intensity over the same period. Lackluster improvements in carbon intensities have led in part to some countries' inability to achieve their targeted emissions levels under the Kyoto Protocol. In contrast to the 1.9 percent decline in annual carbon intensity from 1990 to 2003, EIA projects that worldwide carbon intensities will decline 1.7 percent per year from 2003 to 2030. More specifically, reductions in carbon intensity and in carbon emission levels in developed countries may be completely offset by a wave of much higher energy consumption and carbon emissions from China and other developing countries. In fact, the Congressional Budget Office has projected that over the next 20 years, developing countries will account for two-thirds of the growth in CO_2 emissions.



Source: International Energy Annual 2004

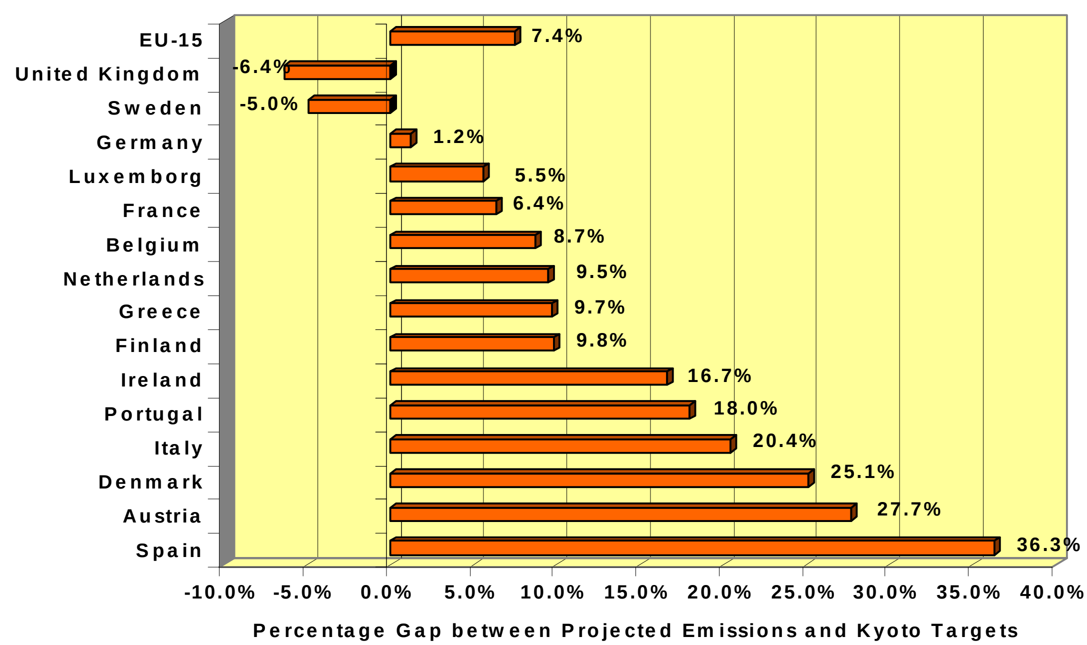
Figure 1-15 Changes in Carbon Intensity for Various Countries, 1994-2004

Even though the United States is making significant carbon dioxide reductions relative to economic growth, this does not reduce the need to pursue measures to reduce greenhouse gas emissions. Improving efficiency, for example, can make great strides as discussed in Section Two. Sections Three and Four discuss opportunities to capture carbon dioxide and Section Five discusses transportation and permanent storage.

Progress on Reducing Carbon Emissions in Other Countries

Despite progress on reducing carbon intensity, higher economic growth and its attendant increase in energy consumption can offset this improvement in environmental performance and lead to an increase in overall greenhouse gas emissions. Even a commitment to the Kyoto Protocol, which is often touted as the solution to global warming concerns, cannot escape this reality. The European Union (EU) experience is a good illustration of how emission reduction targets adopted with noble intentions may not be met. As Figure 1-16 illustrates below, the EU-15 [8] are projected to miss their Kyoto targets by more than 7 percent – by more than 30 percent in some cases – even though the EU adopted an emissions trading program

Record high natural gas prices in Europe have contributed to significantly higher electricity prices. This price escalation has stimulated interest in new coal-fired generation. Given this experience and the significant cost of many carbon reduction strategies, expectations are that the introduction of carbon caps and trading mechanisms would lead to higher electricity prices.



Source: European Environment Agency, Greenhouse Gas Emission Trends and Projections 2006

Figure 1-16: Percentage Gaps between Projected Greenhouse Gas Emissions in 2010 and Kyoto Targets for the EU-15 Countries

In fact, data from the European Environmental Agency[9] reveals that although overall GHG emissions from the EU-15 nations decreased over 1990-2004:

- GHG emissions have risen since 1999 and emissions in 2004 were the highest since 1996.

- In the past year, emission reductions projected for EU-15 by 2004 have become significantly smaller.
- Emissions for the transport sector threaten to offset gains made in the power industry. Transport-related emissions have increased by nearly 26 percent since 1990 and are projected to be 35 percent above 1990 levels by 2010.

Given this limited progress in Europe, other regions are examining more flexible alternatives to GHG emissions. The Asia Pacific Partnership on Development and Climate, for example, is an agreement signed in 2005 by Australia, China, India, Japan, South Korea and the U.S. These partners account for 45 percent of the world's population and 50 percent of man-made CO_2 emissions. The mutual goal is to use economic growth and technology transfer to develop the infrastructure to mitigate GHG emissions.[10]

CONCLUSIONS

- The nation must pursue climate change policies that allow economic growth, support development and demonstration of technologies to improve efficiency, capture greenhouse gases, and transport and store carbon dioxide. The nation will benefit from technologies that can simultaneously address climate change, reduce emissions and improve energy security without damaging the domestic economy or the ability of U.S. business to compete in the global market.
- The coal and power industry will continue to develop carbon capture and storage (CCS) technologies for all generation types (advanced coal combustion and gasification technologies), but needs incentives to be able to do so within the timeframe the technologies are needed to address the climate change issue.
- The U.S. must develop strategies to help developing nations adopt CCS technologies as well. By ardently pursuing the required research, development & demonstration, these technologies will advance more quickly, thus becoming more cost effective and attractive to developing nations.
- When the costs of CCS technologies are driven down to economically feasible levels, they will be deployed.

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[3] Energy Information Administration, International Energy Outlook.

[4] U.S. DOE, National Energy Technology Laboratory, June 21, 2006

[5] The Organisation for Economic Cooperation and Development is a forum where the governments of 30 market democracies address the economic, social and governance challenges of globalization.

[6] Fang ,William, " Key Developments on Climate" presentation on behalf of Edison Electric Institute at Troutman Sanders Coal Based Electric Generation Forum, Lansdowne, Virginia, June 22, 2006.

[7] Raymond Kopp, Resources for the Future, 2005

[8] The number of member countries in the European Union prior to May 1, 2004: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom.

[9] European Environmental Agency, "Greenhouse Gas Emission Trends and Projections in Europe 2006," Copenhagen, 2006.

[10] Montgomery, David and Tuladhar, S. D., "The Asia Pacific Partnership" CRA International, Washington D.C. 2006.

SECTION TWO

Technologies to Reduce Carbon Dioxide Emissions

FINDINGS

- The United States is committed to the use of coal as a primary domestic energy source, especially for generation of electricity. A number of emerging technologies have been identified that can dramatically lower emissions of carbon dioxide (CO_2) to enable continued and increased use of coal.
- Increasing plant efficiency reduces the total amount of CO_2 (and other emissions) produced, thus reducing the amount of CO_2 that must be captured and stored. Until the time that CO_2 capture and storage technologies have achieved broad commercial applicability, the most cost effective and the only practical way to reduce emissions today is to deploy plants with the highest efficiency commensurate with cost and availability.
- Efficiency is at the root of reduced emissions. With any coal combustion technologies – pulverized coal (PC), circulating fluidized bed (CFB) and integrated gasification combined cycle (IGCC) – improvements in efficiency are possible and ready for continued research, development and demonstration (RD&D). New technologies for converting the energy within the fuel to usable electric power can raise efficiencies from today's typical unit at 37 percent to 42 percent by presently available advanced technologies. Further advances to 48 percent, as measured by higher heating value (HHV), can become commercially available after 2015, with construction completed two to four years later. This translates to about a 25 percent reduction in CO_2 per kilowatt-hour (kWh) of electricity produced.
- The existing generation base can benefit from new technology to incrementally improve its efficiency and reduce emissions. The diverse range of coal types and qualities in the U.S. drive the need for a portfolio of technologies to be developed to address project circumstances. For example, biomass co-firing has niche application advantages.
- Continued support of RD&D for these technologies is critical to achieving low cost, reliable and clean coal-based power.

Introduction

Although carbon capture and storage (CCS) is often the focus of discussions regarding reduction of greenhouse gases from coal combustion, a number of methods are available for minimizing CO_2 emissions. This section will present a range of

Coal Combustion Terminology

PC *– Pulverized Coal combustion. The most prevalent form of generation today.*
IGCC *– Integrated Gasification Combined Cycle. Converts coal to syngas, then uses combined cycle technology to convert the gas to electricity.*
CFB *– Circulating Fluidized Bed combustion. Fires coal with limestone; designed for sulfur dioxide (SO_2) control and maximum fuel flexibility.*

technologies for reducing and avoiding CO_2 emissions, including:

- Efficiency improvements
- New capacity with lower carbon emissions
  - Supercritical (SC) steam PC/CFB combustion
  - Ultra-supercritical (USC) steam PC combustion
  - IGCC generation
- Improving the efficiency of existing capacity

Boiler efficiency improvements can reduce CO_2 emissions because the same power output is achieved using less fuel. As steam temperatures and pressures increase, unit efficiency also rises. Efficiency of a subcritical (SubC) steam plant can reach about 37 percent (HHV), SC 39.5 percent, and USC steam generators using today's technologies can offer efficiencies of 44 percent. It is anticipated that an advanced USC plant will be constructed during the next seven to 10 years, constituting a benchmark for a 48 percent efficiency coal-fired power plant. This efficiency improvement demonstrates a 25 percent reduction from a baseline subcritical plant in CO_2 and all other emissions. It is estimated that 45 gigawatts (GW) of coal-based generating capacity will be built in the U.S. before 2020.[11] If more efficient USC technology is used instead of subcritical steam, more than 500 million metric tonnes (MMt) of CO_2 could be avoided over the lifetime of those plants, even without installing systems to capture CO_2.

Technology Terminology

Subcritical *– common pressure and temperatures for most existing power plants – operating with steam pressures around 2400 psi at 1000ºF.*

Supercritical *– Emerging application for higher pressure and temperatures (above 3208 psi and 706ºF) power plants where higher efficiencies can be achieved. Requires some use of new materials that can reliably operate at those conditions.*

Ultra-supercritical *– Even higher pressures and temperatures (above 4350 psi and 1112 F); require the application of improved materials*

Advanced ultra-supercritical – *Future capability based on RD&D with advanced materials and operating targets of 1400F and 5500 psi and efficiencies of 48 percent HHV or higher.*

Improvements in efficiency within the existing base of generating units offer opportunities for reduced CO_2 emissions. While not nearly as dramatic in scale as building state-of-the-art high efficiency power plants, small gains can be made to existing units through equipment upgrades, as well as operations and maintenance activities.

In this section, special attention is paid to the timeline of the various technologies for development, demonstration and commercial availability for deployment. In the near and medium term, several options are available for the deployment of high-efficiency generating technologies with reduced emissions of both criteria pollutants and CO_2. The most important include pulverized coal in supercritical and ultra-supercritical steam cycles and circulating fluidized bed in supercritical steam cycle.

Building High Efficiency New Capacity with Lower Carbon Emissions

Importance of Plant Efficiency

> **Efficiency**
> *Efficiency improvement of power generation is by far the most predictable and reliable method to reduce all emissions including CO_2. Fuel and transportation cost savings help pay the cost.*

The economic benefits from improved power plant efficiency and reliability are generally well understood. Less often appreciated is the fact that increased plant efficiency lowers all plant emissions without installation of additional environmental equipment. Generating efficiency improvement translates directly into lower pollutant and CO_2 emissions per kWh of electricity generated. As CO_2 emission control gains significance, efficiency improvement technologies become the key tool for reducing CO_2 emissions in the near term both for new plants and upgrades of existing plants.

Efficiency is also important to the longer term solutions of reducing CO_2 emissions with CCS technologies. Power plants must be highly efficient to mitigate the energy penalty of CCS technology application. Power generating options, including PC and CFB combustion-fired steam plants with advanced steam parameters and IGCC, are discussed and compared for their efficiency and operational availability. Clearly, improved plant efficiency carrries strong benefits: less overburden to remove during mining, less coal to mine, less coal to ship, fewer emissions of all kinds and less waste disposal.

Pulverized Coal Applications

PC combustion has been the prevailing mode of coal use in power generation worldwide since the 1920s. Efficiency improvements are achieved by operation at higher temperature and pressure steam conditions.

Today, typical subcritical steam operating parameters are 2400 psig/1000ºF (163 bar/538ºC) with single reheat. Efficiency of a subcritical steam plant with such steam parameters can reach about 37 percent, as calculated by higher heating value (HHV) methodology.

Pulverized Coal Supercritical Steam

SC is a thermodynamic term for super heated steam that is at a pressure high enough to escape the energy penalty (latent heat) typically associated with a phase change from liquid to vapor. The objective of operating under supercritical conditions is simply to improve thermodynamic efficiency and, therefore, plant efficiency. As steam pressure and superheat temperature are increased above 3208 psi (225 atm) and 706 °F (375°C), respectively, the steam becomes supercritical; it does not produce a two-phase mixture of water and steam, and does not have a range of heat content in which the boiling steam can be heated without increasing its temperature (latent heat). Instead, it undergoes gradual transition from water to vapor in the heat content range of 850-1050 Btu/lb with corresponding changes in physical properties such as density and viscosity.

Supercritical steam plants have been in use since the 1950s, primarily in Europe, and sporadically also in the U.S. since the 1960s, but improvements in materials and plant reliability and increasing demand for higher efficiency are making this system the common choice of new coal-fired utility plants worldwide. A schematic of advanced pulverized coal-fired power plant with forced circulation boiler equipped with scrubbers for flue gas desulphurization (FGD) and selective catalytic reactor (SCR) for deep reduction of nitrogen oxides (NO_X) is shown in Figure 2-1.

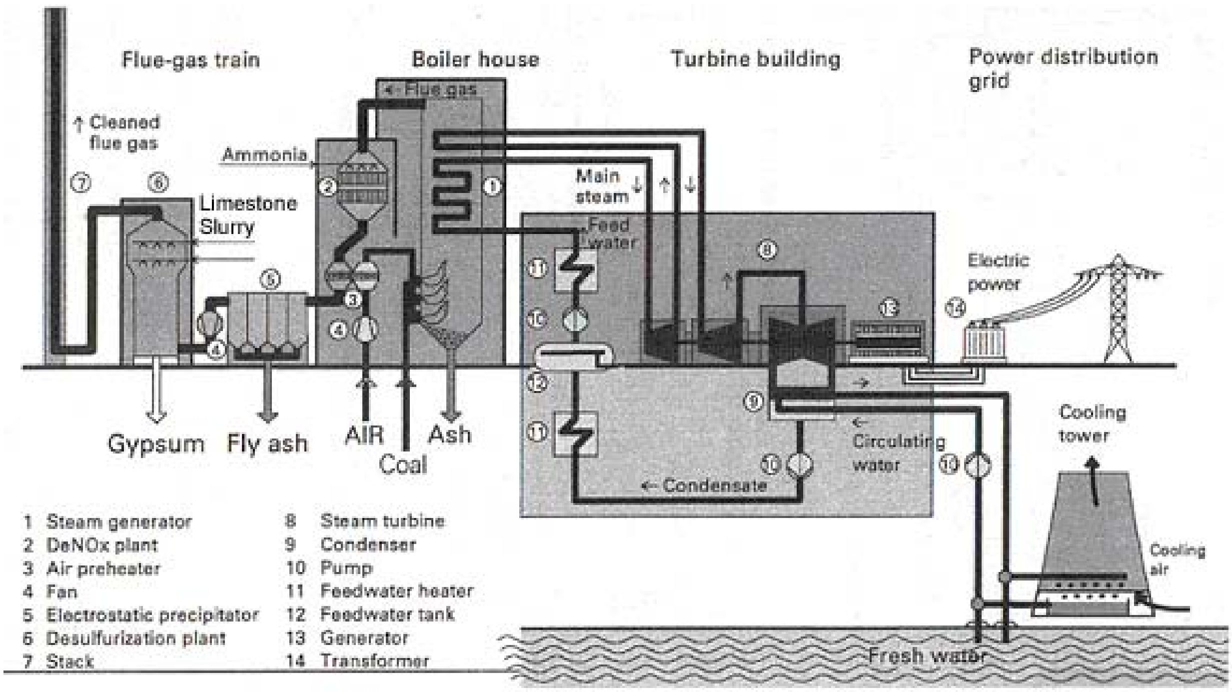
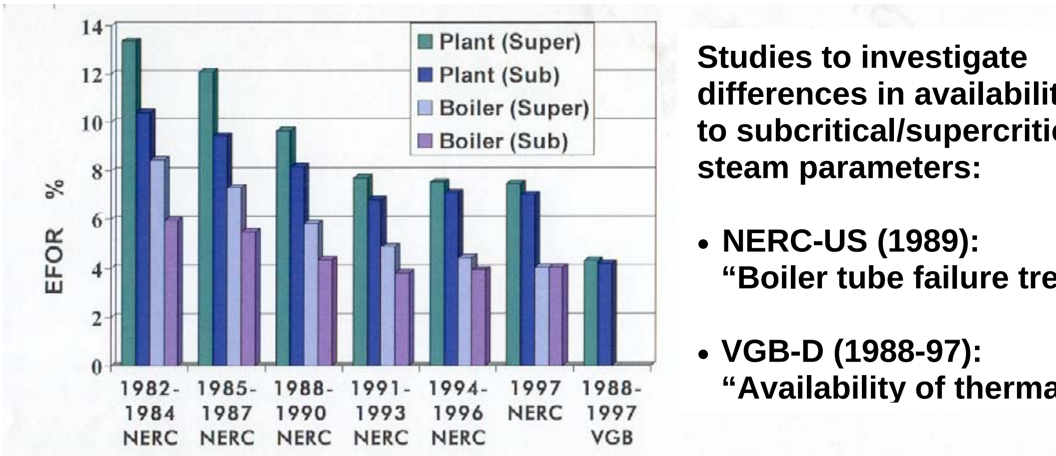


Figure 2-1: Schematic of Advanced PC Power Plant[12]
Source: Termuehlen and Empsperger

The Electric Power Research Institute (EPRI, Armor, et al.[13]), reviewed the performance and history of PC/SC units in the U.S. and in Europe where most SC steam plants have been operating since the 1950s. The first units operating at supercritical pressures were introduced, initially in the United States and Germany in the late 1950s. American Electric Power put the Philo supercritical unit in service in 1957 and Philadelphia Electric soon followed with Eddystone 1, a unit still in service. Today, worldwide, more than 500 supercritical units are operating with ratings from 200 MW to 1300 MW. For newly ordered plants, steam parameters are in the range of 1000-1100° F and 240-260 bar. The increased pressures and temperatures provide significant efficiency improvements over subcritical units, and therefore require less fuel and produce fewer environmental emissions of sulfur dioxide (SO_2), NO_X, CO_2 and particulates.

About 160 PC/SC plants are operating in the U.S., most constructed in the 1970s. These plants show efficiency advantages of about 2.9 points (36.6 percent vs. 39.5 percent [HHV]), amounting to a relative 7.9 percent advantage over subcritical steam units with comparable availability, as shown in Figure 2-2.



EFOR= planned + forced outages, percent of expected mission hours

Figure 2-2: Comparison of Availability of Subcritical and Supercritical PC Plant

There is renewed interest in SC steam plants today, mainly because their higher efficiency and reduced emissions. Supercritical steam parameters of 3625 psi (250 bar) and 1000°F (540°C) single or double reheat with efficiencies of 39.5 percent (HHV) represent a mature technology that has achieved commercial operation in U.S. boiler plants.

The efficiency of PC/SC power plants can be further increased in steps to 43 percent (HHV) and beyond, as illustrated in Figure 2-3. Adjusting the air ratio, lowering the stack temperature, increasing pressure, adding additional reheat stages and lowering condenser pressure are steps that can improve the thermal efficiency of the steam cycle.

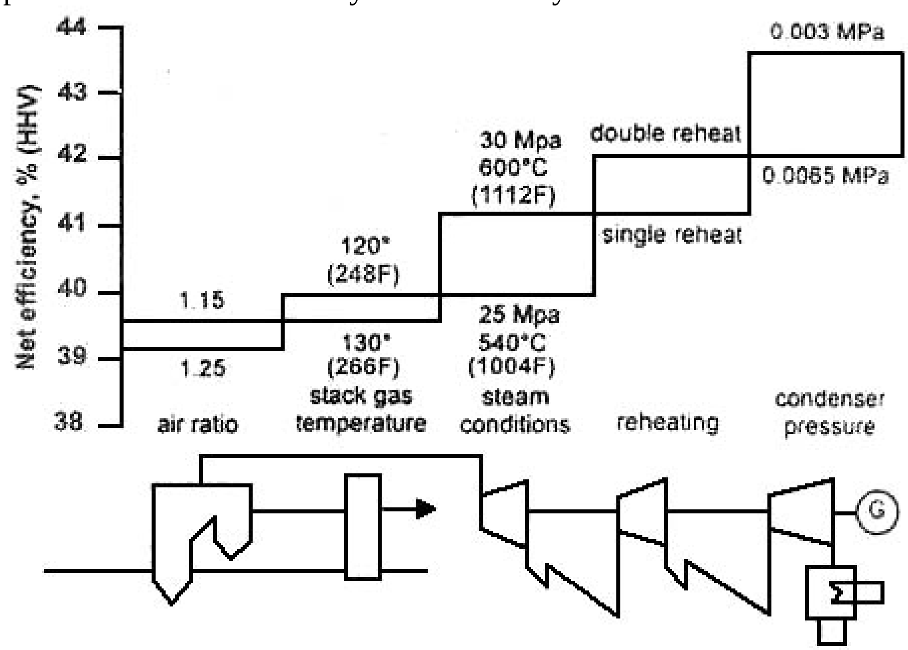


Figure 2-3: Efficiency Improvement Measures for PC/SC plants
(after Schilling ,VGB 1993)

Ultra-Supercritical Steam PC

Ultra-supercritical steam (USC) parameters of 4350 psi and 1112°F (300 bar and 600°C) can be realized today, resulting in efficiencies of 42 percent (HHV) (and as high as 44 percent with additional reheat and very cold condenser temperatures that may not be readily available in the U.S.) for pulverized coal-fired power plants. There are several years of experience with these 1112°F (600°C) plants in service, with excellent availability. USC steam plants in service or under construction in Europe and Japan during the last decade are listed in Figure 2-4.

> **Temperature**
> *Plant efficiency increases by about 1 percentage point when both superheat and reheat temperatures can be increased by 20°C.*

Operating Experience with Supercritical Combustion Plants

Power Station	Cap. MW	Steam parameters	Fuel	Year Com m	Boiler/steam line materials	Turbine materials
Matsuura 2	1000	255bar/598°C/596°C	PC	1997	Super304H/P91	TMK1
Skærbæk 3	400	290bar/580°C/580°C/580°C	NG	1997	TP347FG/P91	COST 501 F
Haramachi 2	1000	259bar/604°C/602°C	PC	1998	Super304H/P91	HR1100
Nordjyiland 3	400	290bar/580°C/580°C/580°C	PC	1998	TP347FG/P91	COST 501 F
Nanaoota 2	700	255bar/597°C/595°C	PC	1998	TP347FG/P91	Toshiba 12Cr
Misumi 1	1000	259bar/604°C/602°C	PC	1998	Super304H/HR3C/P91	TMK2/TMK1
Lippendorf	934	267bar/554°C/583°C	Lignite	1999	1.4910/p91	COST 501 E
Boxberg	915	267bar/555°C/578°C	Lignite	2000	1.4910/p91	COST 501 E
Tsuruga 2	700	255bar/597°C/595°C	PC	2000	Super304H/HR3C/P122	Toshiba 12Cr
Tachibanawan 2	1050	264bar/605°C/613°C	PC	2001	Super304H/P122/P92	TMK2/TMK1
Avedore 2	400	300bar/580°C/600°C	NG	2001	TP347FG/P92	COST 501 E
Niederaussen	975	265bar/565°C/600°C	Lignite	2002	TP347FG/E911	COST 501 E
Isogo 1	600	280bar/605°C/613°C	PC	2002	Super304H/P122	COST 501 E
Materials guide:						
Superheaters: TP347FG: Fine Grain 18Cr10NiMoNb, Super304H: 18Cr9Ni3Cu, HR3C: 25Cr20Ni , 1,4910: 18Cr12Ni2½Mo						
Steam lines & headers: P91: 9CrMoVNb , P92: 9Cr½Mo2WVNb , E911: 9CrMoWVNb , P122: 11Cr½Mo2WCuVNb						
Turbine rotors: COST 501 F: 12CrMoVNbN101 , COST 501 E: 12CrMoWVNbN1011 , HR1100: 111Cr1.2Mo0.4WVNbN						
Turbine materials: TMK1 10Cr1.5Mo0.2VNbN , TMK2: 10Cr0.3Mo2W0.2VNbN , Toshiba: 11Cr1Mo1WVNbN						

Figure 2-4: USC Steam Plants in Service or Under Construction in Europe and in Japan [14]

Further improvement in efficiency by higher ultra-supercritical steam parameters depends on the availability of new high-temperature alloys for boiler membrane wall, superheater and reheater tubes, thick-walled headers and steam turbines. Two major development programs in progress, the Thermie Project of the European Commission and the Ultra-Supercritical Materials Consortium in the U.S., aim at 5439 psi, 1292 °F/1328 °F (375 bar, 700 °C/720 °C), and 5500 psi, 1346 °F/1400°F (379 bar, 730 °C/760 °C), respectively. The timeline of materials development and its relationship with advanced steam parameters is shown in Figure 2-5 and the reduction of CO_2 emission as a function of plant efficiency is illustrated by Figure 2-6; the plant efficiency increases by about 1 percentage point for every 20°C rise in superheat and reheat temperature.

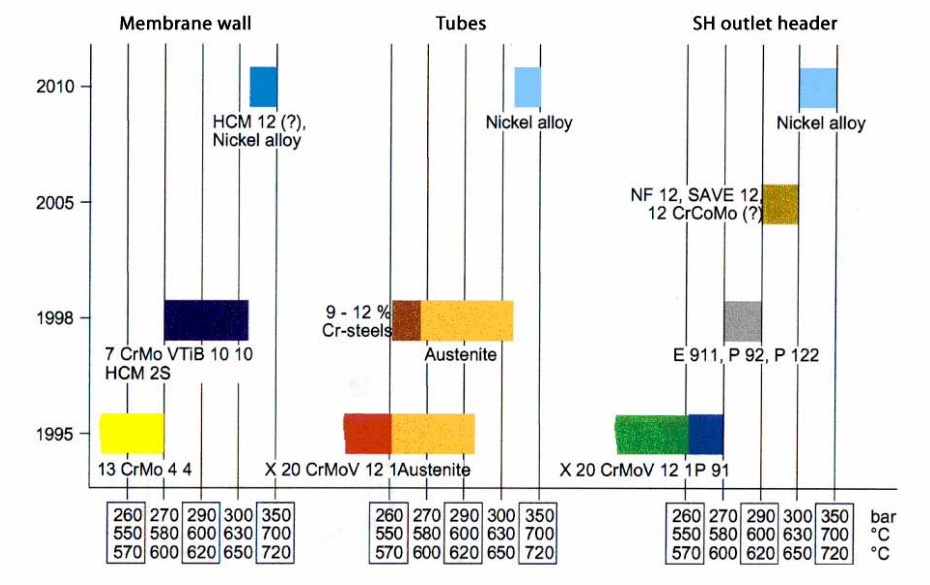


Figure 2-5: Stages in Materials Development and Related Advanced Steam Parameters[15]

Source: Henry, et al.

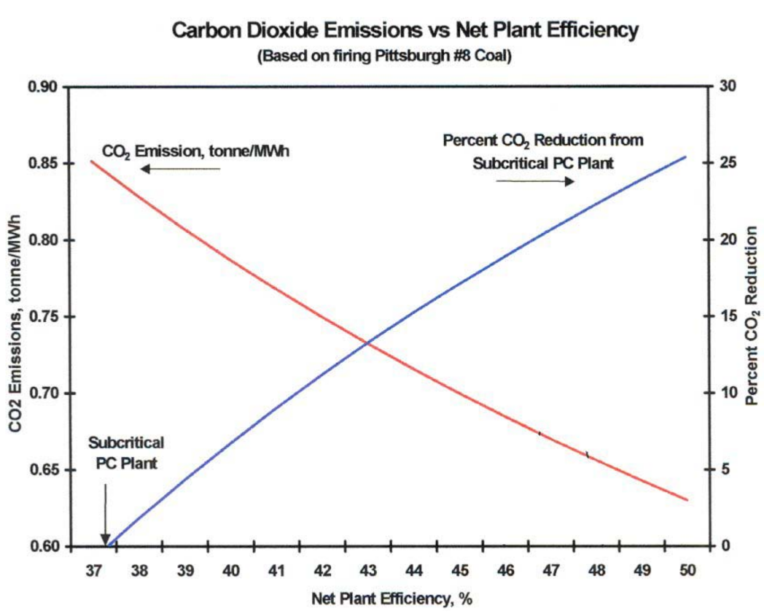


Figure 2-6: CO_2 Emission vs. Plant Efficiency (HHV) [16]

Source: Booras and Holt

As advanced materials are proven and brought into the marketplace, an advanced ultra-supercritical plant operating at 1293°F (700 ºC) is expected to be built during the next seven to 10 years, constituting a benchmark for a 47 percent efficiency (HHV) coal-fired power plant that would result in more than 25 percent reduction in CO_2 and all other emissions.

Normalized information from several sources in the technical literature on efficiency, coal consumption and CO_2 emissions comparisons for 500 MW output PC/SubC, PC/SC and PC/USC plants are presented in Figure 2-7. Because these data are normalized, they may differ from single source data quoted earlier in the discussion.

Impact

By comparison to existing plants, if more efficient USC technology is used CO_2 emissions will be reduced more than 500 million metric tonnes over the life of those plants, even without installing a system to capture CO_2.

An advanced USC plant with an efficiency of 46-48 percent (HHV) would emit approximately 25 percent less CO_2 per MWh generated than an equivalent-sized subcritical PC unit. Of course, this reduction would also apply to emissions such as SO_2 and NO_X, since the more efficient plant would use less coal to produce the same energy. It is estimated that by 2020, about 45 GW of new coal-based capacity will be built in the U.S. prior to widespread adoption of CCS technologies. By comparison to existing plants, if more efficient USC technology is used, CO_2 emissions will be about 500 MMt less over the life of those plants, even without installing a system to capture CO_2 from the exhaust gases.

	New Subcritical	PC/SC	PC/USC
Heat Rate Btu/kWe-h	9950	8870	7880
Gen. Efficiency (HHV)	34.3%	38.5%	43.3%
Coal use (10^6t/y)	1.549	1.378	1.221
CO_2 emitted (10^6t/y)	3.47	3.09	2.74
CO_2 emitted (g/kWe-h)	931	830	738
Assumptions: 500 MW net plant output ; Illinois #6 coal ; 85% Capacity Factor			

Figure 2-7: Comparative Coal Consumptions and Emissions of Available Coal Combustion Technologies[17]

Source: MIT Coal Study 2007

Pursuing Even Higher Efficiency with Ultra-supercritical Combustion and Advanced Materials

Based on a review of worldwide materials development activities, the U.S. advanced ultra-supercritical program has defined the RD&D necessary to build upon these capabilities. The U.S. program includes work to identify, fabricate and test advanced materials and coatings with mechanical properties, oxidation resistance and fireside corrosion resistance suitable for cost-competitive boiler operation at steam temperatures of up to 1400°F (760°C) at 5500 psi (38.5 MPa). In addition, the materials issues that affect boiler design and operation at temperatures as high as 1600°F (870°C) are being explored.

Steam turbine materials are being evaluated in a separate project. Principal activities at present include identification of materials suitable for both welded and non-welded rotor configurations, blading and castings and development of coatings resistant to oxidation and solid particle erosion.

View of the Future:
Economics of Advanced Ultra-supercritical Steam Designs

Initial economic analyses have focused on a boiler design with a steam cycle operating at about 1350°F-1400°F (730°C-760°C) at 5500 psi (38.5 MPa). Unit efficiency is estimated to be about 45 percent (HHV) for a single reheat cycle and 47 percent (HHV) for a double reheat cycle. Based on these efficiency advantages, breakeven cost analyses were performed to assess critical cost considerations for advanced ultra-supercritical designs in light of cost projections developed for subcritical, supercritical and IGCC units. The analyses employed a 20-year breakeven consideration, assumed capacity factor of 80 percent, and coal cost of $1.50 per MMBtu. Among the key results from breakeven analyses:

- *An advanced ultra-supercritical plant can be cost-competitive even if it costs 12 to 15 percent more than a comparable-scale facility built using conventional boiler and cycle designs.*
- *Boiler and steam turbine capital costs can be higher by 40 to 50 percent.*
- *Balance of plant costs are expected to be 13 to 16 percent lower than those for existing boiler and steam cycle designs because of reduced requirements for coal handling, emissions control and other auxiliary components.*

Source: EPRI

Circulating Fluidized Bed Combustion Applications

In fluidized combustion, coal is combusted in a hot bed of sorbent particles suspended in motion (fluidized) by combustion air that is blown in from below through a series of nozzles. Circulating fluidized bed combustion (CFBC) is the most common fluidized combustion design today. CFBC operates at gas velocities high enough to entrain a large portion of the solids (at approx.12-30 ft/s, 4-10 m/s), which then is separated from the flue gas and recycled (recirculated) to the lower furnace to achieve good carbon burnout and SO_2 sorbent utilization. Typically, an external hot cyclone is used at the furnace exit as a separation device. CFBC has high fuel flexibility; it can accept diverse and low quality fuels.

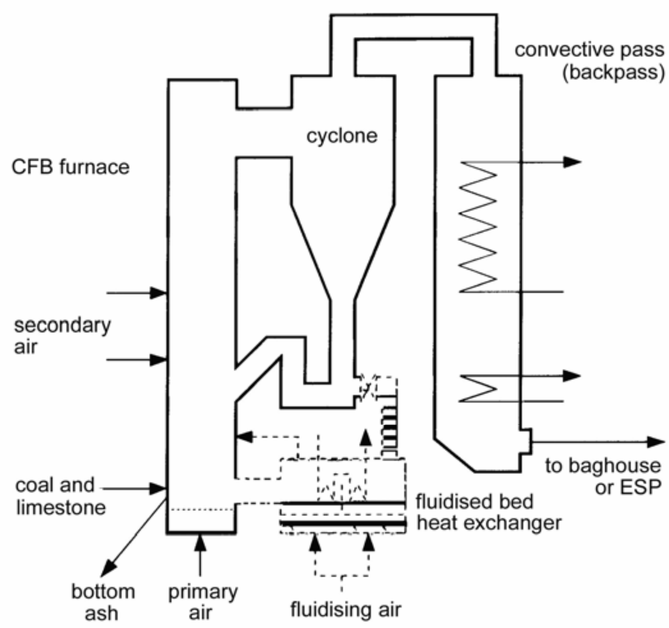


Figure 2-8. Circulating Fluidized Bed Schematic[18]
Source: VGB Kraftwerktechnik

For SO_2 capture and fuel flexibility, limestone is fed into the fluidized bed in addition to crushed coal. The limestone is converted to free lime, a portion of which reacts with the SO_2 to form calcium sulfate. During the conversion process, CO_2 is released. For high-sulfur coals (> 2 percent S), Calcium-to-Sulfur (Ca/S) molar ratios of 2-2.5 are required to achieve 90 percent sulfur removal. For low-sulfur coals (< 1 percent), Ca/S molar ratios as high as 3-6 are required to achieve the same 90 percent sulfur removal. Due to the high molar ratios of limestone required to capture and remove the SO_2, reagent and disposal costs are 50-100 percent higher than for PC plants with FGD systems using typical bituminous coals. For the same reason, this technology emits higher quantities of CO_2 than conventional SO_2 scrubber technologies and offers no strategic benefit with respect to reducing CO_2 emissions. However, niche applications where the combustor is operated with biomass fuel make this configuration ideal due to its robust fuel flexibility.

Application

CFBC does not have a strategic advantage for CO_2 removal for most fuels because the limestone increases CO_2 production. However, the design is very flexible in regard to fuel and presents itself as a likely candidate for use with biomass.

Integrated Gasification Combined Cycle (IGCC)

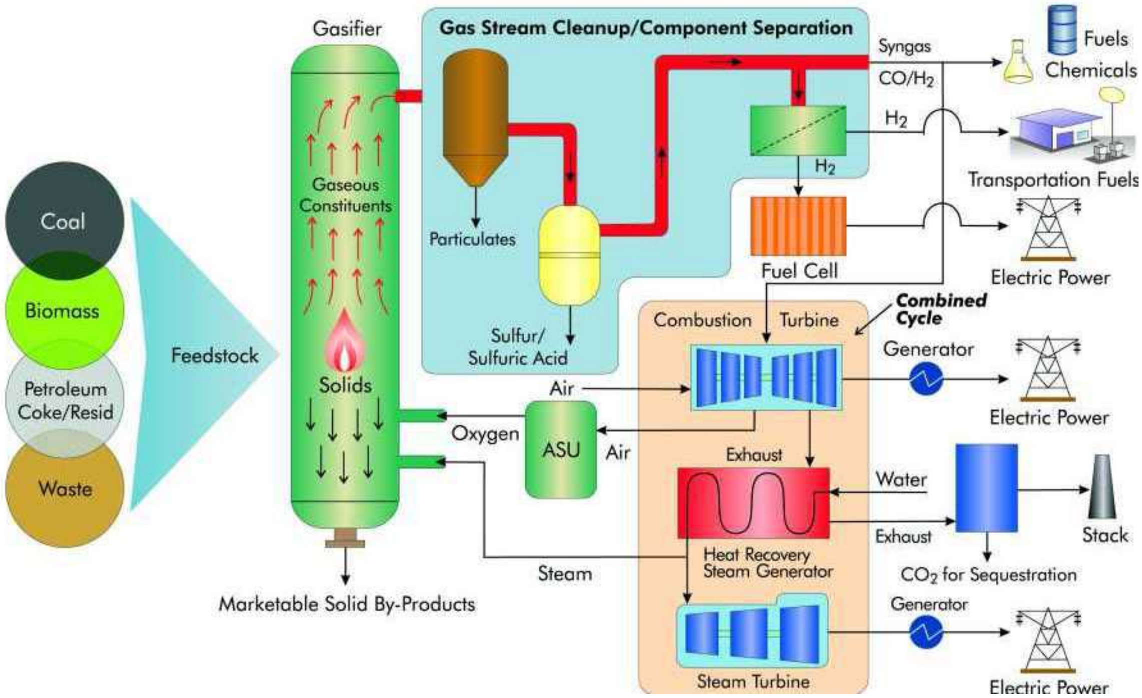


Figure 2-9: Gasification-Based System Concepts
Source: DOE

Gasification-based technologies use a partial combustion of coal with air or oxygen to produce a synthesis fuel gas (syngas). This gas is then cleaned to remove contaminants before it is used as fuel in a combustion turbine or further processed into a feedstock for industrial production. As with combustion technologies, higher efficiency results in lower emissions per MWh. IGCC has begun to be commercially offered following a couple of power demonstration units in the U.S. and Europe (the majority of gasifiers are operating in refineries producing chemical feedstock).

While the IGCC concept has been demonstrated on a very limited basis, utility power generation demands introduce new challenges that will require significant RD&D to successfully overcome. The gasification process, as with most industrial chemical processes, operates best under steady-state conditions. The load change conditions associated with utility electricity generation will burden the technology. A commercial power plant has to make changes in output to match electricity demand on the grid. The many chemical processes will have to respond to these changes on a real-time basis, a complexity not currently proven for IGCC. In addition, the gasifier and associated gas cleanup systems will be exposed to a much larger range of fuel quality than experience has demonstrated. Again, this variation introduces conditions that require more RD&D to commercialize.

EPRI Coal Fleet for Tomorrow IGCC Augmentation Plan

ERPI, as part of its industry-led "CoalFleet for Tomorrow" initiative, created an RD&D augmentation plan for IGCC technology. The purpose is to identify RD&D needs, over and above those already under way or planned, to foster the early deployment of IGCC technology.

EPRI has established process technology premises representing state-of-the-art for IGCC. These designs are the baseline from which the technology will advance through RD&D efforts. They were chosen because they were proven at commercial-scale operation at the end of 2004, and they do not necessarily represent what IGCC suppliers offer today. Current RD&D efforts analyzed later in this paper will identify the impact of the design improvements being offered for new IGCCs.

IGCC Baseline Design: In Commercial-scale Operation at End of 2004

The baseline IGCC plant is built around two General Electric 7FA combustion turbines, each capable of producing 197 MW of power when fired on synthesis gas (syngas), a mixture of CO and H_2. The net plant power is approximately 520 MW. IGCCs with oxygen-blown gasifiers have a two-train air separation unit (ASU) with 25 to 50 percent of the air for the ASU being supplied by extraction from the 7FA compressors. The designs do not include a spare gasifier. The gas clean-up includes a carbonyl sulfide (COS) hydrolysis catalyst, an activated carbon bed for mercury capture, and a low-temperature acid gas removal (AGR) process such as methyl di-ethanol amine (MDEA) or Selexol®. The captured hydrogen sulfide (H_2S) is converted to yellow cake sulfur in a Claus plant, and the Claus tail gas is recycled to upstream of the AGR system. The sulfur level in the syngas after the AGR is 30 ppmv regardless of the sulfur content of the feed coal. NO_X control is accomplished by diluting the syngas with the excess nitrogen produced by the ASU and, if necessary, saturation of the syngas by contact with hot water. A selective catalytic reactor is not included. Steam conditions in the heat recovery steam generator (HRSG) are 1800 psia/1000ºF/1000ºF (124 bara/538ºC/538ºC).

IGCC Historical Availability

The availability (percent of time available to generate electricity) for IGCC plants are of particular concern because of the relative newness of the technology and the tremendous cost to plant owners when the plant is unavailable for operation. Furthermore, the IGCC availability factors are for coal-based operation only and do not take into account backup operation of the plant on other fuel. Figure 2-10 shows the availability history of six coal-based IGCC units. While only one of the coal-based IGCCs has reached the expected availability level shown in Figure 2-10 for only one year, EPRI believes proven modifications that are included in future IGCCs will yield availability improvements.

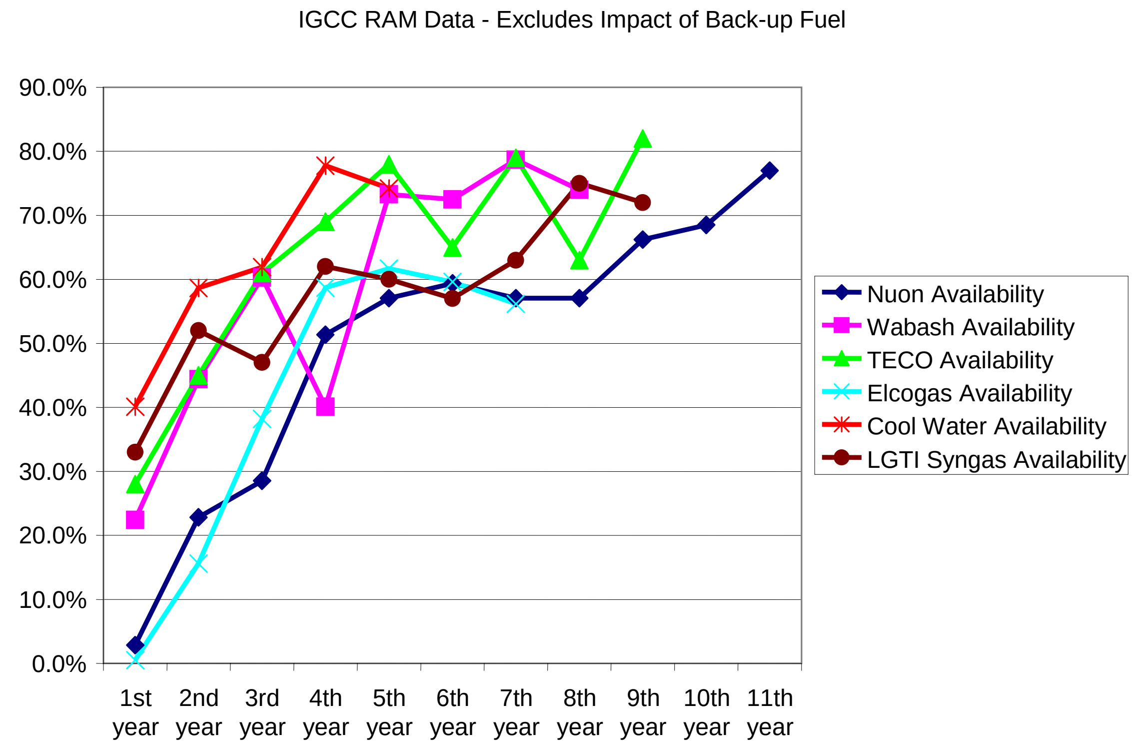


Fig 2-10: History of IGCC Availability (Excluding Operation on Backup Fuel) EPRI 2005 (from Phillips (EPRI) CCEP research symposium Stanford University 2005)

Availability, Thermal Efficiency and Capital Cost for Future Plants

The expected availability, thermal efficiency and capital cost for the baseline designs are presented in Figure 2-11. In the case of the IGCC baselines, EPRI used cost and performance results from various studies conducted in the 2002-2004 timeframe. The ranges included in the IGCC values reflect the impact of using different gasification technologies (e.g., dry feed versus slurry feed). All capital cost data have been adjusted to second quarter 2005 dollars. Also presented in the tables are the goals for coal power plants for the year 2020 contained in the joint Coal Utilization Research Council (CURC) - EPRI Roadmap first published in 2002.[19] A detailed discussion about plant and CCS costs can be found in Section Six.

Technology	Coal Type	Predicted Availability	Efficiency, HHV basis	Capital Cost, $/kW 2Q 2005 USD
SCPC 2005	E. Bit. or PRB	86%	38 – 39%	1400 – 1600
IGCC 2005	E. Bit. or PRB	80-85%	38 – 40%	1500 – 1900
CURC 2020 Roadmap	E. Bit. or PRB	90%	42 – 46%	1220 – 1350 Target

Figure 2-11: Availability, Thermal Efficiency and Relative Capital Cost Expected from Baseline Designs of Advanced Coal Power Generation Technologies **Compared to CURC Targets for Coal Power Plants in 2020**

Improving Efficiency of IGCC – 2010

The CoalFleet IGCC RD&D augmentation plan identified a number of RD&D areas which could lead to improved IGCC efficiency. These are highlighted in bold in Figure 2-12 below. For plants in operation by circa 2010, the use of advanced F class combustion turbines (e.g., the GE 7FB or Siemens 5000F) would improve efficiency from 38.9 percent to 39.5 percent for a slurry fed gasifier without CO_2 capture with high sulfur bituminous coal (i.e., Pittsburgh #8), resulting in a lowering of CO_2 emissions per kWh of 1.5 percent. For a dry feed gasifier with Powder River Basin (PRB) sub-bituminous coal, the efficiency would improve from 39.2 percent to 39.8 percent, reducing CO_2 by 1.5 percent per kWh.

Improving Efficiency of IGCC – 2015

For the mid-term (2015), three so-called “G-class” combustion turbines (CTs) are on the market: Mitsubishi Heavy Industries’ (MHI’s) 501G (60 Hz) and 701G (50 Hz) and Siemens’ SGT6-6000G. All G-class turbines have some steam-cooled stationary components (e.g., transition pieces) and operate at a higher firing temperature than F-class CTs. This yields an improvement in heat rate of 1 to 2 percent. With RD&D leading to the use of syngas-fired G class combustion turbines and to recover ASU compressor intercooler heat, efficiency could be improved to 40.9 percent, or a 5.1 percent reduction in CO_2 per kWh by 2015 for a slurry fed gasifier and improved by 0.7 percent for a dry feed gasifier for a 1.5 percent reduction in CO_2 per kWh.

Improving Efficiency of IGCC - 2020 and beyond

With adequate RD&D, over the longer term the following areas could lead to efficiency improvements:

- Ion transfer membrane (ITM) technology for the production of high purity oxygen
- Replacing “G class” with “H class” combustion turbines
- Supercritical heat recovery steam generator and steam turbines
- Dry feed pump for pressurizing coal to the gasifier
- Warm gas cleanup
- Replacing an H Class combined cycle with a hybrid fuel cell – combustion turbine (FC-CT) power block

If successful, these could improve efficiencies without CO_2 capture to around 50 percent with CO_2 emissions reduced by around 25-30 percent per kWh.

See Figure 2-12 on following page for IGCC Improvement Roadmap.

IGCC Long-Term Improvement Roadmap
High Sulfur Bituminous Coal (i.e., Pitts #8)

Estimates from EPRI's CoalFleet for Tomorrow

Slurry Fed Gasifier Without CO_2 Capture — 2nd Q 2005 USD

	Total $/kW	CC $/kW	Gfr $/kW	ASU $/kW	Gen $/kW	HHV Heat Rate	HHV Effcy	Avail-ability	Net MW
2005									
Baseline technology	1734	580	707	211	236	8782	38.9%	83.0%	550
2010									
Advanced F class CT	1677	580	671	200	227	8633	39.5%	83.0%	630
Add SCR	1692	587	678	201	227	8650	39.4%	83.0%	629
Improved Refractory	1518	587	504	201	227	8650	39.4%	90.0%	629
2015									
F class to G class CTs	1432	576	462	184	210	8515	40.1%	90.0%	810
Recover Intercooler Heat	1418	576	453	184	206	8348	40.9%	90.0%	826
Improved Hg detection	1418	576	453	184	206	8348	40.9%	90.0%	826
2020									
ITM Oxygen	1323	561	441	119	201	8047	42.4%	90.0%	857
G class to H class CTs	1297	550	430	116	200	7834	43.6%	90.0%	877
Ultralow DLN Combustors	1289	544	429	116	199	7818	43.6%	90.0%	879
2025									
Supercritical HRSG	1273	544	420	114	195	7646	44.6%	90.0%	898
Dry Feed Pump	1261	543	417	105	195	7340	46.5%	90.0%	900
Warm Gas Cleanup	1199	543	357	104	195	7194	47.4%	90.0%	900
H class to FC hybrid	1174	543	337	98	195	6637	51.4%	90.0%	900

Sub-bituminous coal (PRB)

Dry Feed Gasifier Without CO_2 Capture — 2nd Q 2005 USD

	Total $/kW	CC $/kW	Gfr $/kW	ASU $/kW	Gen $/kW	HHV Heat Rate	HHV Effcy	Avail - ability	Net MW
2005									
Baseline technology	1772	571	810	180	211	8712	39.2%	85.0%	528
2010									
Advanced F class CT	1713	571	769	171	203	8566	39.8%	85.0%	605
Add SCR	1727	578	776	171	203	8584	39.8%	85.0%	604
Lower SGC steam P	1632	578	681	171	203	8875	38.4%	90.0%	584
2015									
F class to G class CTs	1536	567	624	157	188	8736	39.1%	90.0%	752
Recover Intercooler Heat	1520	567	612	157	184	8565	39.8%	90.0%	767
Improved Hg detection	1520	567	612	157	184	8565	39.8%	90.0%	767
2020									
ITM Oxygen	1431	552	596	102	180	8257	41.3%	90.0%	793
Dry Feed Pump	1360	552	526	102	180	8236	41.4%	90.0%	795
G class to H class CTs	1332	541	513	99	178	8018	42.6%	90.0%	813
Ultralow DLN Combustors	1324	535	512	99	178	8002	42.6%	90.0%	815
2025									
Supercritical HRSG	1309	535	501	97	177	7825	43.6%	90.0%	833
Warm Gas Cleanup	1245	535	439	95	177	7661	44.5%	90.0%	833
H class to FC hybrid	1216	535	415	90	177	7069	48.3%	90.0%	833

Figure 2-12: IGCC Improvement Roadmap [20]

Improving the Efficiency of Existing Generating Capacity

While building new high efficiency capacity offers lower CO_2 emissions rates per kWh of electricity produced, a wholesale replacement of existing generating units cannot be accomplished in the near future. Besides daunting economic considerations, the existing subcritical units play a key role in reliable power generation. These units have a more robust capability for load following and significant load turn-down during non-peak times, which is essential in meeting the peaks and valleys associated with load demand on the grid. Simply put, small subcritical units, with their high responsiveness to power demand fluctuations, contribute significantly to a robust portfolio of generation technologies.

While not nearly as dramatic in scale as building state-of-the-art high efficiency power plants, small gains can be made to existing units through equipment upgrades as well as operations and maintenance activities. These improvements will be very specific to a given unit, but in general can lead to efficiency improvements and result in reduced CO_2 emission rates. A sample of potential improvements is briefly presented below.

Equipment Upgrades

Turbine blading and steam path upgrades, including turbine control valve upgrades, can result in more efficient use of the energy from steam produced in the boiler. Upgrades to the cooling tower heat transfer media may be applicable on certain units, which would yield lower circulating water temperatures. Dropping condenser temperature reduces back pressure, which increases turbine efficiency. Variable speed drive technology can be applied to pump and fan motors. By only running large pumps and fans at speeds necessary to support a given load, auxiliary power consumption is reduced. Air preheater upgrades can be applied to many older units. Modern heat transfer media and seal upgrades increase heat recovery and reduce leakage, resulting in less wasted heat and energy.

While not exhaustive, the items listed above are a sampling of options that can offer very measurable increases in unit output and/or reductions in CO_2 emissions. In a recent study by American Electric Power (AEP), presented to the Asia Pacific Partnership in September 2006, AEP estimates these types of equipment upgrades would yield reductions of more than 3.5 million tons of CO_2 per year across its generation fleet. Efficiency upgrades also can be implemented in conjunction with retrofits of other air pollution control equipment, such as selective catalytic reduction and/or flue gas desulphurization, to offset associated parasitic losses.

Maintenance Practices

While plant maintenance has historically been considered necessary for retaining good unit reliability and availability, strategic maintenance planning also may result in higher unit efficiency. Older equipment is often found degraded from its design performance levels. Pumps, fans, heat exchangers and similar equipment may continue to operate reliably even when efficiency is reduced. Good maintenance practices should include measures to restore design performance. By anticipating equipment wear, it can be repaired or replaced before it becomes a performance liability. Best practices can be applied in this area to optimize maintenance associated with equipment performance. An effective approach to maintenance should include a proactive assessment of critical equipment condition, economic justification and comprehensive outage planning.

Coal Quality Impacts on Boiler Efficiency

An improved understanding of the interplay between coal quality and the performance of a specific boiler can lead to significant increases in boiler efficiency at little or no cost to the utility because the cheapest coal does not necessarily produce the cheapest electricity or produce the lowest CO_2 emissions. The potential for improved boiler efficiency by selection of the optimal fuel quality is especially high in cases in which a boiler is fed a fuel that is below design specifications. Other benefits of burning higher quality coal can include increased capacity, reduced maintenance, increased availability, reduced emissions and reduced tonnage of ash for disposal.

> **Efficiency Upgrade Candidates**
>
> - *Turbine blades*
> - *Turbine valves*
> - *Cooling towers*
> - *Pump and fan motors*
> - *Air preheaters*
> - *Heat exchangers*
> - *Maintenance practices*

Coal quality impacts boiler efficiency primarily by impacting parasitic power. For example, increasing the heating value of coal by cleaning to remove ash-forming minerals reduces the tons of coal that must be pulverized for a given thermal output as well as the tons of ash that must be heated, collected and removed from the boiler. Because cleaning removes ash-forming minerals at different rates, cleaning can change the composition of the ash. Changes in ash composition can have positive or negative impacts on boiler performance and this can also impact efficiency.

For scrubbed power stations, reducing the sulfur content of coal by cleaning has minimal impact on the power demands of the scrubber and therefore minimal impact on plant efficiency. However, there is a secondary CO_2 reduction benefit gained by cleaning to remove sulfur because the production of one ton of lime produces 0.95 to 1.2 tons of CO_2.[21] Therefore, coal cleaning reduces the amount of lime required by a scrubber thus reduces the CO_2 emissions produced by the plant.

Coal Quality and Power Production Costs

Because the cost of coal typically represents well over half of the cost of operating a coal-fired power station, buying less costly coal can appear to be a way to reduce the operating costs of the station. Unfortunately, less costly coal is generally of lower quality, which can have a negative impact on boiler efficiency as well as boiler maintenance costs and boiler availability. In some cases, unplanned outages are caused by coal quality issues related to materials handling problems or excessive boiler tube wear.

Because of the financial importance of balancing the issues of coal cost, coal quality and the cost of power generation, some utilities have studied these relationships in depth. The coal quality properties that most affect boiler operation are ash content, ash composition, sulfur content and moisture content. The general trend of the relationship between coal quality and coal quality related costs is essentially linear until coal quality becomes worse than the design specification for the boiler. As coal quality drops below design specifications, costs rise exponentially until, at some point, the boiler cannot be operated. [22]

Coal Quality and Boiler Efficiency

In a study sponsored by the Tennessee Valley Authority (TVA) and the U.S. Department of Energy (DOE)[23], over 20 years of coal data were statistically analyzed for effects on boiler availability, boiler efficiency and maintenance costs. The average boiler efficiency relationship for all TVA boilers was described as:

> Boiler Efficiency = Ke – 0.022 (Ash %) – 0.010 (Moisture %) – 0.039 (Age of the Boiler) where Ke varies between 89.51 and 91.43 depending on the type of boiler.

The impact of boiler age was believed to be related in part to air in-leakage in older boilers, which can be mitigated by proper maintenance.

Using the average efficiency relationship and assuming Ke = 90 and a boiler age of 20 years, boiler efficiency is calculated as 88.8 percent when fed a coal with an ash content of 17 percent and a moisture content of 5 percent. If the coal is cleaned to 10 percent ash and the moisture held constant, the boiler efficiency increases to 89 percent, an increase of two-tenths of a percentage point.

The impact of improved coal quality can be greater for specific boilers. For example, the relationship for TVA's Johnsonville Units 1 – 6 from the same study was described as:

> Boiler Efficiency = 90.558 – 0.156 (Ash %) – 0.041 (Moisture %) – 0.026 (Age).

Assuming a boiler age of 20 years, the Johnsonville Units 1-6 have a calculated efficiency of 87.2 percent when fed a coal with an ash content of 17 percent and a moisture content of 5 percent. If the coal is cleaned to 10 percent ash and the moisture held constant, the boiler efficiency increases to 88.3 percent, an increase of just over 1 percentage point.

In a study by EPRI[24], pilot-scale combustion tests were performed on Texas lignite as-mined and the same lignite after cleaning. The ash content of the as-mined lignite was 17.2 percent and the ash content of the cleaned lignite was 9.7 percent. Moisture content was unchanged by cleaning. In this study, cleaning was found to increase boiler efficiency from 81.7 percent to 82.6 percent, an increase of just under a percentage point. In addition to increased boiler efficiency, the study estimated that cleaning would reduce maintenance costs by $2 million dollars per year and ash disposal costs by $1.2 million per year.

CONCLUSIONS

- New high-efficiency power plant designs using advanced pulverized coal combustion and gasification could reduce (compared to existing coal plants) more than 500 million metric tonnes (MMt) of CO_2 over the lifetime of those plants, even without installing a system to capture CO_2 from the exhaust gases.
- Currently available, commercially-proven technologies can significantly increase the efficiency of domestic electric power generation and thereby reduce the emission of CO_2 and regulated air pollutants such as SO_2, NO_X, mercury and particulates. Pulverized coal and gasification plants announced or beginning construction today have improved efficiencies – about 25 percent better relative to the average of existing power plants, with correspondingly better environmental performance.
- For units already in operation, improvements in efficiency offer opportunities to reduce CO_2 emissions. Retrofits are normally undertaken to bring about efficiencies and reduce emissions, but in some cases, required upgrades to emissions equipment may use a significant amount of parasitic energy and thus offset any corresponding energy efficiency gains, possibly resulting in lower overall unit efficiencies.
- The use of coal cleaned to higher quality levels offers the potential to both reduce pollutants such as particulates, mercury and SO_2, as well as increase efficiency.
- The U.S. generation industry will require a portfolio of highly efficient advanced clean coal technologies to provide competitive options for the range of domestic coals. Continued support of RD&D and deployment for the identified potential solutions for PC, circulating fluidized bed combustion (CFBC) and IGCC technologies to determine actual cost and reliable performance is critical to achieving low-cost, reliable and clean coal-based power.
- Continuing RD&D for advanced materials capable of handling the higher temperatures and pressures of ultra-supercritical plants is needed.
- Variances in plant designs and fuel characteristics prevent "one-size-fits all" solutions for all plants. A portfolio of clean coal technologies will be needed in the future. It is too early in the research stage to assume which technologies will be the most promising.

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SECTION THREE

Technologies for Capturing Carbon Dioxide

FINDINGS

- Recovery of carbon dioxide (CO_2) from power plants with current technologies reduces the electrical output and adds significant cost to the net cost of power. Thus, to partially compensate for the higher operating costs, carbon capture technologies presently lend themselves to more efficient power plant designs, such as those described in Section Two rather than the designs found in most existing power plants.
- New technologies are being developed on national and international fronts to address these high costs. Some of these technologies will be tested at a pilot scale in the next few years. Other advanced technologies are only in laboratory stages of development. Efforts need to continue to support the testing and demonstration of these technologies to accelerate their readiness for deployment.
- Development of a portfolio of capture technologies will be necessary in order to make substantial reductions in CO_2 emissions from coal combustion.
- Carbon capture can be accomplished (at some cost); the real difficulty is developing the technologies sufficiently so they will work reliably and economically and be available to the industry before stringent limitations on CO_2 emissions are mandated.
- Technologies today are being tested in the lab and in a limited number of small demonstrations. It will be many years before a portfolio of "winning" technologies is determined and sufficiently tested for broad commercial applications.
- The application of carbon capture technologies will be more cost effective (for pulverized coal [PC] or integrated gasification combined cycle [IGCC] plants) if applied as original equipment rather than retrofitted to existing plants. These new facilities can be properly integrated to account for internal energy savings and to optimize all the power plant's systems to minimize the inefficiency associated with a retrofit design. At this early stage of the technology, some planning for future carbon capture technology can take place today to provide space and other considerations so as to make plants built today adaptable to future requirements.

Introduction

Reducing carbon dioxide emissions into the atmosphere will require technologies that remove CO_2 from the combustion gas stream of a PC boiler or from the hydrogen stream of an IGCC reactor before combustion. Only one commercially proven technology – amine scrubbing – is currently available for coal combustion and one – Selexol® absorption – for gasification. Application of these technologies requires extensive energy to recover the CO_2 and imposes significant energy and cost penalties on the operation of the power plant. Because of the limitations of existing technologies to meet carbon capture goals, extensive research to develop and demonstrate alternative technologies is needed. Significant efforts to find new options have been initiated on a broad front. This report describes the array of technologies being developed to improve the economics of CO_2 capture.

Conventional Pulverized Coal Plants

Capturing CO_2 poses large challenges in the areas of cost and energy consumption, and is a major economic impediment to the large-scale adoption of sequestration technology. For conventional combustion-based plants, the partial pressure of CO_2 in the flue gas is very small, only 2-3 psia. Of the five major types of processes being studied, the most developed is chemical absorption, which is used in the chemical and natural gas processing industries, although at a smaller scale than required for power plants. A few power plant demonstrations using amine-based CO_2 removal systems are under way worldwide on relatively small generating units.

The chief drawbacks are the need for large and expensive gas contacting and pumping equipment as well as the large amount of energy required to release captured CO_2 and regenerate the sorbent for reuse. The total impact on a new supercritical unit would raise the cost of electricity (COE) by greater than 60 percent and reduce net electrical output by about 30 percent. The cost impact of a retrofit application for an existing subcritical unit would be even greater. Nonetheless, gaining experience operating pilot and full-scale systems at power plants is crucial to overall commercialization efforts, and these processes offer a solid basis for such testing as well as opportunities for cost and performance improvement.

Although monoethanol amine (MEA)-based amine-based systems show great promise for removing CO_2 from flue gas, they faced a significant challenge in dealing with oxygen in flue gas. Oxygen contributes to degradation of amines by participation in the formation of heat-stable salts. The presence of heat-stable salts induces corrosion in the metal components of the amine system. Heat stable salts require reclamation or replacement of the solvent, as well as incurring costs for disposal of the byproducts of the reclamation process. Developers of new amine processes are hoping to develop new formulations that are not affected by the presence of oxygen. These new amine formulations are also tailored to reduce the thermal requirements for regeneration and improve the overall process economics.

Gasification Plants

A broad range of process options is available for removal of concentrated CO_2 from IGCC streams, which are usually at pressures from 300-1000 psi. Further, since synthesis gas (syngas) contains no oxygen, the formation of heat-stable salts is significantly mitigated for amine-based processes. As a consequence, the cost per ton of CO_2 removed from IGCC power plants is lower than for PC plants, primarily because of the higher CO_2 concentration in IGCC stream than in PC plant flue gas. Cost reductions and performance improvements for “high pressure” CO_2 removal systems are still necessary to approach the goals of the U.S. Department of Energy’s (DOE’s) Vision 21 (DOE's program to develop advanced concepts for a new fleet of emission-free coal-based energy facilities that would co-produce electricity and clean fuels). The demonstration of these concepts is central to the FutureGen program discussed in Section Seven.

Of the five major types of processes being explored, the most developed is physical absorption. According to a recent DOE-Electric Power Research Institute (EPRI) study, an IGCC unit with CO_2 capture could reduce CO_2 by 90 percent and have a COE 25 percent lower than that of a PC unit using MEA, assuming IGCC power block cost reduction goals are met. In absolute terms, however, the extra capital cost and energy penalties for IGCC CO_2 removal are high, and also warrant further research, development and demonstration (RD&D).

Overview of CO_2 Removal Technologies

Applicability

In general, CO_2 removal processes are equally applicable for either PC or IGCC processes. The major difference in applying these technologies lies in the gas stream's overall pressure and the partial pressure of CO_2 within the stream. Typically, PC combustion sources generate low overall pressure and low partial pressure streams. IGCC processes typically generate high pressure streams with high CO_2 partial pressures.

Technologies used to capture CO_2 and other gases that are used in other industries may be applicable to coal-based power plants. Much work remains to determine how to integrate these technologies into combustion-based and IGCC plants. Even with sufficient RD&D to make these technologies commercially available, capital and operating and maintenance (O&M) costs will be significant and reductions in power plant efficiency considerable.

Removal Technologies

Conventional processes for CO_2 separation/removal from multi-component gaseous streams include:

- chemical absorption
- physical absorption
- adsorption
- gas permeation (i.e., selective membranes)
- cryogenic cooling or cryogenic-supported absorption

Sorbents

Research is focusing on development of improved sorbents that have higher capacity for CO_2 and require less energy for regeneration.

Chemical absorption is the most common of these, most frequently using organic chemical absorbents such as MEA, di-ethanol amine (DEA), methyl di-ethanol amine (MDEA), tert-ethanol amine (TEA), and 2-amino-2-methyl-1-propanol (AMP). Alkaline compounds such as sodium hydroxide, potassium carbonate and sodium carbonate also are used. The absorbed CO_2 then is removed from the solvent by either raising the temperature and/or lowering the pressure of the amine solution to desorb CO_2.

For flue gas-based processes, the liberated CO_2 stream may contain small amounts of sulfur dioxide (SO_2), sulfur trioxide (SO_3) and other acidic gases, and may require further cleanup before compression and transportation to an end user or sequestration site. These acid gases also contribute to forming heat-stable salts that deactivate the sorbent. The chief drawbacks of amine-based processes are their limited absorption and the significant amount of energy necessary to release the captured CO_2. Typically, one pound of low-pressure steam is required to liberate one pound of absorbed CO_2. Thus, the absorber and stripper towers are large and require very intense heat to regenerate the amines for reuse. Amine-based systems also require large pumps to circulate liquid absorbents and heat exchangers to manage the heat released in the process, as well as large compressors that raise the flue gas pressure to compensate for the pressure drop in the absorber tower.

These drawbacks are not as significant for IGCC facilities. Because much of the CO_2 can be liberated by the significant pressure drop that occurs between the absorber and the regenerator, less steam is required for sorbent regeneration. This results in a smaller energy penalty. Also, the solvent has a tendency to form fewer heat-stable salts because of fewer acid gases and the lack of oxygen in the syngas.

The standard amine-based CO_2 absorption unit design consists of two stages. The flue gas first is passed through an absorption column where the solvent removes most of the CO_2 by chemical absorption. The second is a stripping column where heat is applied to release the CO_2 and regenerate the solvent. The flow sheet is similar to a standard generic gas treatment process. See Figure 3-1. The flue gas and aqueous solvent solution are contacted counter currently in an absorption column, the flue gas entering at the bottom of the column and the CO_2-lean solvent at the top. To minimize solvent degradation, the inlet flue gas temperature should not exceed 150°F (65°C).

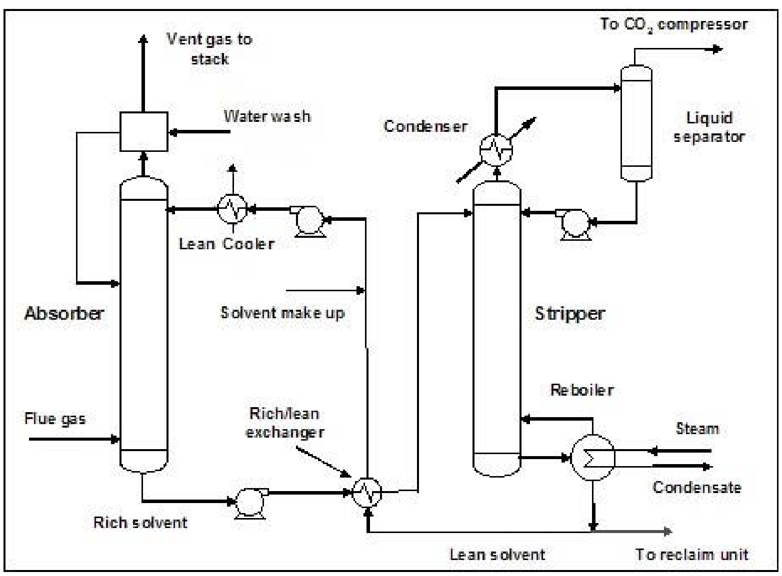

Figure 3-1: Generic Gas Treatment Process

Typically, the lean-solvent enters the absorber at 110°F (43°C) and, as the CO_2 absorption reaction is exothermic, the CO_2-rich solvent leaves the bottom of the absorber at typically 140°F (60°C). The rich solvent passes to a rich-lean solvent heat exchanger where it is heated by the hot-lean solvent leaving the reboiler. The hot-rich solvent then enters at the top of the stripper, with additional heat provided by a steam-heated reboiler that raises the solvent temperature to around 250°F (120°C). To enhance desorption of the CO_2 and reduce the heat required, the stripper operates close to atmospheric pressure. The hot-lean solvent is withdrawn from the reboiler inlet and passed to the rich-lean solvent heat exchanger, and then to an additional cooler where the temperature is reduced ahead of re-entering the absorber.

Any solvent carried over from the absorber by the CO_2-depleted flue gas is recovered by a water-wash system and returned to the center of the absorber. The water added also helps dilute the solvent to the required level. Solvent carried over from the stripper by CO_2 is recovered in a condenser and returned to the top of the stripper. A small portion of the lean solvent is extracted from the reboiler and fed to a reclaim unit where any degradation products are precipitated out after reaction with caustic soda. This small amount of material can be kept suspended and injected into the boiler for disposal by incineration.[25]

Research is focusing on development of improved absorbents that have higher capacity for CO_2, have a lower propensity for degradation (formation of heat-stable salts), and require less energy for regeneration.

Physical absorbents, such as methanol (Rectisol®), dimethyl ether of polyethylene glycol (Selexol®) and other organic sorbents, dissolve CO_2 without chemical reaction. CO_2 liberation and solvent regeneration are accomplished by pressure swings and/or temperature swings. These fluids are most often used in IGCC plants where CO_2 pressure is high, and much of the regeneration is accomplished by reducing pressure. Several of these technologies are also candidates for treating flue gases from coal combustion sources.

Higher cost and the lack of pressure as a driving force is the primary drawback of physical absorbent technologies for PC units. Research for PC and IGCC applications is focusing on development of improved sorbents that have higher capacity for CO_2 and require less energy for regeneration.

Adsorption-based CO_2 removal processes are based on the significant intermolecular force between gases and the surface of certain solid materials, such as activated carbon. The adsorbents are usually arranged as packed beds of spherical particles. Either pressure or temperature swings are employed to capture and release CO_2 in a cyclic adsorption/desorption sequence. Adsorption processes are used commercially for CO_2 removal from industrial steam-based natural gas reformers. While they are relatively simple, the CO_2 loading and selectivity of available adsorbents are low. Since flue gas is at atmospheric pressure, some compression is necessary, particularly with pressure swing desorption. Very high CO_2 purity can be obtained, but overall costs are high. Further, the separated CO_2 is produced at a low pressure. Activated carbon or carbon molecular sieves would be the likely adsorbents used for CO_2 removal from PC units. The development of these technologies would eliminate the need to pump solutions and would be much simpler to operate.

Research is focusing on development of an improved array of new molecular adsorbent materials that have high capacity for handling CO_2.

Gas separation membranes operate on the principle of diffusion. The components that diffuse more rapidly end up in the permeate. Porous structures in the membrane material permit the preferential permeation of certain gas stream components from one side of the membrane to the other. The primary design and operational parameters for membranes are selectivity and permeability. Permeability and design operating pressure are the major limiting factors for membranes used to remove CO_2 from flue gas, which means very large surface areas are necessary and thus, costs are high. In order to provide an adequate driving force, the flue gas must be compressed to at least 50 psi. A two-stage separation system may be required to effectively remove CO_2 from flue gas, at about twice the cost of amine-based systems. A two-stage system would also require further compression. The limitation of pressure is not as significant a concern for IGCC systems, and membrane technology can provide a pathway to significant cost savings compared to amine-based systems.

> **Terminology**
> ***Permeation,*** *in physics, is the penetration of a substance (permeate) through a solid.*

A new class of high-temperature, high-pressure "ion transport membranes" is being developed, which may enhance the performance of membrane processes. Most of this research, at present, is focused on O_2 separation from air, but it may also be a promising research field for CO_2 separation.

Gas absorption membranes consist of microporous solid membranes in contact with an aqueous absorbent. In a common arrangement, called membrane-assisted absorption, CO_2 diffuses through the membrane and is then absorbed by MEA. The equipment for this process tends to be more compact than that for conventional membrane systems. Since the captured CO_2 is in the liquid phase, it can be cost-effectively pumped at high pressure for discharge from the plant or to a sequestration site. Membrane-assisted absorption costs are comparable to those for conventional MEA absorption.

RD&D is focused on identifying a more optimal membrane/absorber coupling, improving the economics.

Cryogenic separation of flue gas constituents involves compressing and cooling the flue gas in stages to induce phase changes in CO_2 and other gases. Although cryogenic processes can lead to high levels of CO_2 recovery, the processes are very energy intensive. The cost of cryogenic CO_2 removal may not be significantly higher than for amine absorption processes.

Research is focused on coupling cryogenic separation with adsorbent liquids to improve both processes in a synergistic approach.

CO_2 hydrate separation processes are designed to produce CO_2 clathrates in high-pressure, multi-component gaseous streams to selectively remove CO_2 and hydrogen sulfide (H_2S). In the SIMTECHE process, syngas (generated by a gasifier operating in a shift mode) is cooled to about 35°F and contacted with a nucleated water stream to form a CO_2/H_2S hydrate slurry. The remaining gas, containing primarily hydrogen (and also nitrogen if using an air-blown gasifier), is separated from the hydrate slurry in a gas/liquid separator. The CO_2 /H_2S hydrate slurry can be decomposed in a "flash reactor." Performance and economic analyses suggest this process may be substantially less energy intensive and less costly than established processes for extracting CO_2 from shifted synthesis gas and compressing it for transportation.

New organic salt "promoters" have been identified, which could enable very high CO_2 separation rates. These compounds are highly soluble in water and could permit CO_2 hydrate formation at temperatures as high as 75-85°F and with low CO_2 partial pressures. Operation under these conditions should reduce both parasitic power losses and cost.

Advanced Technology Development

A wide array of technologies are currently being investigated as shown in Figure 3-2.

CO_2 Removal Technology	Development Stage	Process Type
Ammonia-Based Process For Multicomponent Removal From Flue Gas	Pilot in Engineering	Chemical Absorption
Liquid Absorbent For CO_2 Capture	Lab	Chemical Absorption
Oxygen Membrane For Oxy fuel Combustion	Lab	Cryogenic Separation
Advanced Oxy fuel Boilers	System studies	Cryogenic Separation
Oxygen-Based PC Boiler	Theoretical Development	Cryogenic Separation
Oxygen Firing In Circulating Fluidized Bed Boilers	Theoretical Development	Cryogenic Separation
Carbon Dioxide Separation With Microporous Metal Organic Frameworks	Theoretical Development	Adsorption based
Solid Sorbents For CO_2 Capture From Postcombustion Gas Streams	Lab	Adsorption based
CO_2 Adsorption On Solid Amine Sorbent	Theoretical Development	Adsorption based
Carbon Dioxide Capture From Flue Gas Using Dry Regenerable Sorbents	Pilot Scale Testing	Adsorption based
Absorption With Potassium Carbonate	Pilot Scale Testing	Adsorption based
Dry Regenerable Sorbent	Lab	Adsorption based
Metal Monoliths For CO_2 Capture	Lab	Adsorption based
Microporous Metal Organic Frameworks For Removal Of CO_2 From Flue Gas	Lab	Adsorption based
Microporous Inorganic Siliceous Matrix With Amine Groups Physically Bonded On The Membrane	Lab	Membrane
Enzyme Based Membrane	Lab	Membrane
Membrane Separation Process	Lab	Membrane
Ionic Liquids As Novel Absorbents		Membrane
Hydrogen Selective Silica Membranes	Lab	Membrane
Ionic Liquids Based Membranes	Lab	Membrane
Molecular Design Of High Capacity CO_2 Adsorbents	Lab	Adsorption based
Carbon Dioxide Separation With Microporous Metal Organic Frameworks	Theoretical Development	Adsorption based
Solvents For CO_2 Capture	Lab	Chemical Adsorption
Solid Sorbents For CO_2 Capture From Precombustion Gas Streams	Lab	Adsorption based
CO_2 Hydrate Process For Gas Separation From A Shifted Synthesis Gas	Bench Scale	Adsorption based
Membrane For Pre-Combustion Separation Of CO_2	Lab	Membrane

Figure 3-2: Technologies Currently in RD&D for CO_2 Capture

Technologies Readying for Pilot Scale Testing

A number of technologies have progressed from the laboratory to pilot and process development scale. These will likely be ready for demonstration in the next several years and to be ready for deployment as alternatives to MEA type systems in the next 10 years. Deployment will require successful pilot scale testing and operation at a demonstration scale of 50 to 100 MW before companies will have confidence in their cost and performance for large scale systems.

Ammonia Scrubbing for CO_2 Capture – Powerspan – Pilot Testing in 2007

Powerspan's ECO_2™ is a scrubbing process that uses an ammonia-based solution (not an amine) to capture CO_2 from flue gas. The CO_2 capture takes place after the nitrogen oxides (NO_X) and SO_2 capture in Powerspan's ECO® multi-pollutant control technology. Once the CO_2 is captured, the ammonium bicarbonate solution is regenerated to release CO_2 and ammonia (NH_3). The NH_3 is recovered and sent back to the scrubbing process, and the CO_2 is ready for sequestration. Ammonia is not consumed in the scrubbing process and no separate by-product is created.

Both Powerspan and the DOE have conducted laboratory testing of the CO_2 capture process, and Powerspan is preparing for pilot testing, scheduled to begin by the end of 2007. Powerspan laboratory testing of the CO_2 absorption process has demonstrated 90 percent CO_2 removal under conditions comparable to a commercial-scale absorber, confirming test results previously obtained by the DOE under similar conditions.

In September 2005, Powerspan and FirstEnergy announced plans to pilot test the ECO_2™ technology at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio. In May 2006, FirstEnergy announced that its Burger Plant was selected as a carbon sequestration test site by the Midwest Regional Carbon Sequestration Partnership, one of seven regional partnerships set up by the DOE to research carbon sequestration projects throughout the country. These combined projects provide a first opportunity to demonstrate both CO_2 capture and sequestration at a conventional pulverized coal-fired power plant.

The ECO_2™ pilot unit will process a 1-MW slipstream (20 ton CO_2 /day) from the 50-MW Burger Plant ECO® unit, which has proven effective in reducing sulfur dioxide, nitrogen oxides, mercury and fine particulate matter. The pilot program will demonstrate the ability of the CO_2 capture process to be integrated with the ECO® multi-pollutant control process and will confirm process design and cost estimates.

The pilot design parameters, developed by Powerspan, will be specified to enable the ECO_2™ technology potentially to move directly from pilot scale to commercial-scale deployment, with guaranteed costs and performance. Upon successful completion of the pilot scale testing in 2007-08, Powerspan would expect commercial-scale ECO_2™ systems to be available to produce CO_2 for enhanced oil recovery (500-5,000 tons per day CO_2 capture, or 25-250 MW equivalent).

Enhanced Adsorption Solvent for CO_2 Removal – Cansolv – Pilot Test 2007

Cansolv Technologies Inc. (CTI) has been developing amine-based post-combustion CO_2 capture process technology for several years, building on its regenerable SO_2 capture process from oxygen-containing flue gas streams. This experience has enabled Cansolv to define a stabilized CO_2 capture solvent which has demonstrated greatly reduced solvent degradation compared to MEA. Pilot testing with lignite-fired flue gas demonstrated reduced energy consumption compared to MEA using a simple process flow scheme. Adding process enhancements such as split flow, multiple effect regeneration and absorber intercooling can substantially reduce energy consumption, but increase capital cost and process complexity.

A two-month 24/7 pilot test of CO_2 capture was conducted at a Canadian lignite-fired generating station in July/August 2006. The pilot unit treated a flue gas slipstream of 65 cfm, with a CO_2 concentration of 15 percent vol. (dry gas basis, 12 percent wet basis). Performance was measured at an absorber temperature of 50°C and 90 percent CO_2 capture. Because of the errors inherent in the process parameters at this small scale, performance of CTI solvents was evaluated relative to the conventional MEA process. The results for solvent DC-101™ were:

- Regeneration steam: 80 percent of MEA, using simple process flow diagram
- Regeneration steam: 73 percent of MEA, using absorber intercooling
- Solvent loss: <10 percent per year; an order of magnitude less than MEA
- Mass transfer: slower than MEA
- SO_2 impact: no effect; reacts irreversibly with MEA
- CO_2 capacity: solvent circulation equal to MEA

The performance of solvent DC-102™ was even better, again at 90 percent CO_2 capture and relative to conventional MEA.

Cansolv Test Results for Flue Gas Treatment		
Flue Gas Source	PC Flue Gas	NGCC Flue Gas
Gas Composition	15% CO_2 (dry, 5% O_2)	4% CO_2 (dry, 15% O_2)
Regeneration Steam	65% of MEA	75% of MEA
Solvent loss, %/year	12%	12%
Mass transfer rate	Comparable to MEA	Comparable to MEA
SO_2 Impact	Degrades solvent	Degrades solvent
Liquid/Gas Ratio	50% of MEA	50% of MEA

Figure 3-3: Performance of Cansolv D102 Solvent

The data at 4 percent CO_2 and high oxygen level indicate this solvent is a commercially viable candidate for CO_2 capture from combustion turbine exhaust.

The latest development, DC-103™ solvent, shows promising performance in laboratory scale testing. While retaining the high mass transfer rate and low circulation rate of DC-102, it promises greater chemical and thermal stability and lower corrosiveness. Pilot scale testing of this product is being scheduled for this year.

Chilled Ammonia Scrubbing for CO_2 Capture – Alstom/EPRI – Pilot Testing in 2007

Alstom and EPRI will conduct a 5 MW pilot scale test of a chilled ammonia process for recovery of CO_2. The process has been tested in a laboratory and shows promise in reducing the capital and operating costs associated with MEA-based CO_2 capture systems. The pilot plant is to be constructed at We Energies' Pleasant Prairie Power Station. Currently, 24 power generating companies support the pilot test.

The chilled ammonia process is a solvent-based process for post-combustion CO_2 control. It is expected to consume much less energy than amine-based technology, the most widely studied process to date, having been applied commercially to other sources. Initial estimates indicate that steam and power consumption are only about 15 percent and 55 percent, respectively, of the requirements for a commercially available MEA-based amine system. Largely because of these reduced energy penalties, the cost of capturing and regenerating CO_2 from a coal-fired power plant using the chilled ammonia process is estimated at less than $20 per ton CO_2, with the potential of being even lower.

The main advantages of the chilled ammonia system over amine processes are:

1. Heat of reaction with CO_2 is only about 25-30 percent that of the amine reaction, reducing energy consumption of the process
2. High CO_2 loading per unit of recycled liquid, reducing the size of vessels, pumps and other related equipment
3. Low temperature regeneration that enables the use of low-grade heat
4. Regeneration possible at higher pressure, reducing CO_2 compression costs

The main concern with using ammonia for CO_2 capture is its relatively high vapor pressure, which, under conventional flue gas conditions, results in unacceptable ammonia emission. The use of a chilled ammonia process overcomes this problem.

Oxy Fuel Combustion Process

Oxy fuel combustion is gaining more support as a viable CO_2 capture alternative for reducing CO_2 emissions. This process is suitable for PC and circulating fluid bed (CFB) boilers. Figure 3-4 shows a schematic diagram of the Oxy-coal-fired PC boiler process that is suitable for retrofitting existing boilers as well as for new boilers. This process involves recycling a portion of flue gas so as to mimic the performance of the air-fired boiler. Oxygen is mixed with the recycled flue gas to produce the oxidant stream. The flue gas is scrubbed to remove sulfur oxides (SO_X). However, the removal of nitrogen from the process increases constituent levels in the recycle loop by a factor of about 3.5 times compared to air firing. Before deciding whether to scrub before or after the point of recycle, the impact of this concentrating effect on equipment design and corrosion potential must be carefully considered. After most water is condensed out, the flue gas stream is rich in CO_2. This stream contains impurities mainly comprising atmospheric gases (oxygen, nitrogen and argon) and small amounts of SO_2 and NO_X. The flue gas is compressed and purified to prepare the CO_2 stream for sequestration.

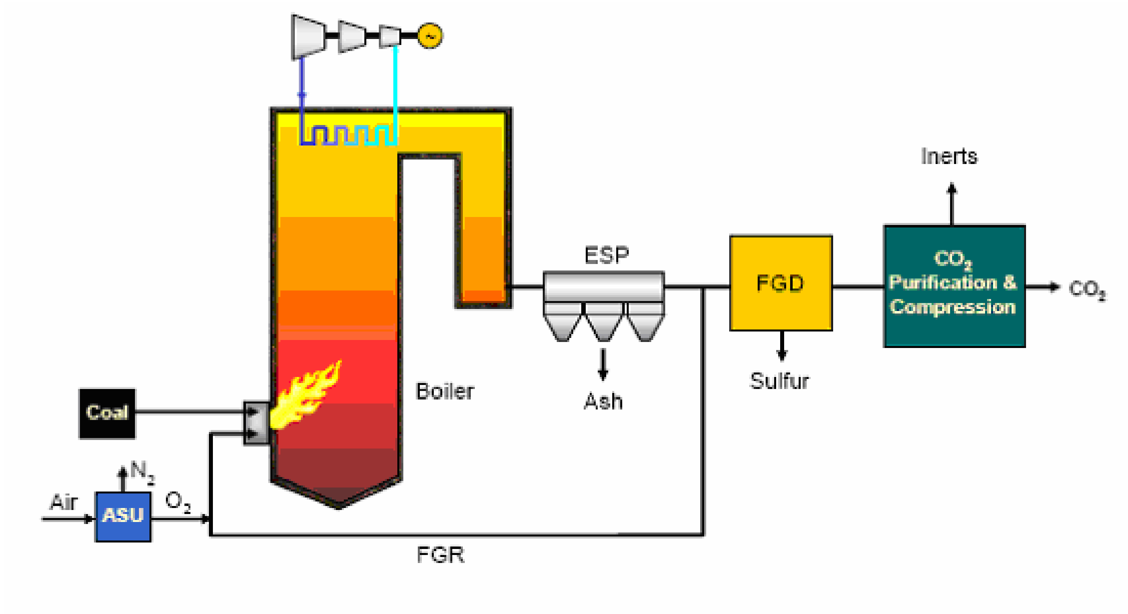

Figure 3-4: Oxy Coal-Fired PC Boiler CO_2 Capture[26]
Source: Praxair

The Oxy coal-fired boiler has been studied in laboratory and small pilot units of up to 3 MW_{th}. Before this technology can be implemented at commercial scale, further scaleup through larger pilot and intermediate-scale demonstrations will be required. Although in theory the coal-fired boiler can be operated to mimic the air-coal-fired boiler; many issues need further investigation. Some issues that must be addressed are the performance of Oxy fuel burners, Oxy fuel flame properties, heat transfer characteristics and materials compatibility due to different chemical environments within the boiler.

Larger pilot-scale demonstrations of the entire systems at ~10 and ~30 MW_e, respectively, have been announced by Babcock & Wilcox (B&W) and Vattenfall, by an Australian-Japanese project team. These larger tests will allow verification of mathematical models and provide engineering data useful for designing larger systems. The flue gas from the boiler will contain up to 75-85 percent by volume CO_2 (on dry basis). The purity required for sequestration is generally > 95 percent. To achieve this purity, one-stage or two-stage partial condensation can be used. If CO_2 is to be used for enhanced oil recovery (EOR), then oxygen content in CO_2 must be reduced to meet oil producer specification. Current requirement for EOR in the U.S. calls for < 10 ppm O_2 in CO_2. To achieve more stringent specification for the EOR application, distillation will be necessary. The recovery of CO_2 generally will range from 85 to 95 percent depending on the CO_2 concentration in the feed and final CO_2 purity required.

SaskPower Project

During the next 20 to 30 years, SaskPower will be making major decisions concerning refurbishing or replacing virtually its entire fleet. Saskatchewan's 300-year supply of mineable lignite coal remains the most cost-efficient and stable-priced fuel for baseload generation, but there are environmental concerns.

For several years, SaskPower has been evaluating technologies for carbon dioxide management in coal-fired power plants. Recently, it announced a $1.5 billion (Canadian) clean coal project to capture over 90 percent of the CO_2 produced from coal combustion. This project will result in a power plant that not only produces 300 net MW of electricity, but will capture about 8,000 tonnes of CO_2 a day to be used to extract millions of barrels of oil from Saskatchewan oilfields through EOR. Additional emissions-control technologies also will be incorporated, bringing the clean coal project to near zero emission status.

After evaluating the technology options, SaskPower, B&W Canada and Air Liquide agreed in late 2006 to jointly develop Oxy fuel technology as the core process for the unit to be located at their Shand facility near Estevan. Marubeni Canada and Hitachi will supply the turbine generator set. The Oxy fuel technology nearly eliminates emissions of combustion by-products, including greenhouse gas emissions and may be the worlds first near-zero emissions pulverized coal unit.

In deciding on Oxy fuel, SaskPower thoroughly examined and researched both Oxy fuel and the post-combustion clean-up processes. Based on the current state of both technologies, and project-specific parameters, it selected Oxy fuel and expects it to provide the best environmental performance and lowest cost.

If successful, this power plant will be the first of its kind in a utility scale application. A decision on whether to proceed will be made in mid-2007, with an in-service date of 2011. In support of this effort, B&W also has announced it is converting its existing 30 MW_{th} Clean Environment Development Facility in Alliance, Ohio, for Oxy fuel testing in early summer 2007.

Other Technologies

Mineral Carbonation

The process of capturing a high concentration of CO_2 in a stable form of metal oxide-bearing materials fixes the CO_2 as carbonates with naturally occurring silicates. Mineral carbonation is based on the reaction of CO_2 with metal oxide-bearing materials to form insoluble carbonates, with calcium and magnesium being the most attractive metals.[27] Once the carbon has been stored through mineral carbonation, virtually no emissions of CO_2 occur because of leakage.

While theoretically attractive, kinetic modeling indicates little driving force for the desired reactions. In addition, a large scale mining operation would be required to supply materials for this process – about 1.6 to 3.7 metric tonnes of silicate and 2.6 to 4.7 metric tonnes of disposable materials per metric tonne of CO_2 fixed in carbonates. One metric tonne of carbon dioxide corresponds to 0.27 metric tonnes of carbon only in theory; in practice the overburden makes it correspond to about 2 metric tonnes of raw mineral. It follows that mineral carbonation to store the CO_2 produced by burning coal would require installing a mining industry on a scale comparable to the coal industry itself.

Chemical and Thermal Looping

In chemical looping,[28] [29] [30] [31] an oxygen donor, usually a solid oxide such as calcium sulfate ($CaSO_4$) is stripped of the oxygen by coal in a high temperature endothermic reducer reactor to form calcium sulfide (CaS), and the oxygen reacts with the coal to form CO, CO_2 and H_2. The CaS is then transported to an exothermic oxidizer reactor, in which it is oxidized by air to form $CaSO_4$. The calcium is cycled between the two reactors forming a chemical loop, resulting in a coal gasification process without the need of an oxygen plant (Figure 3-5).

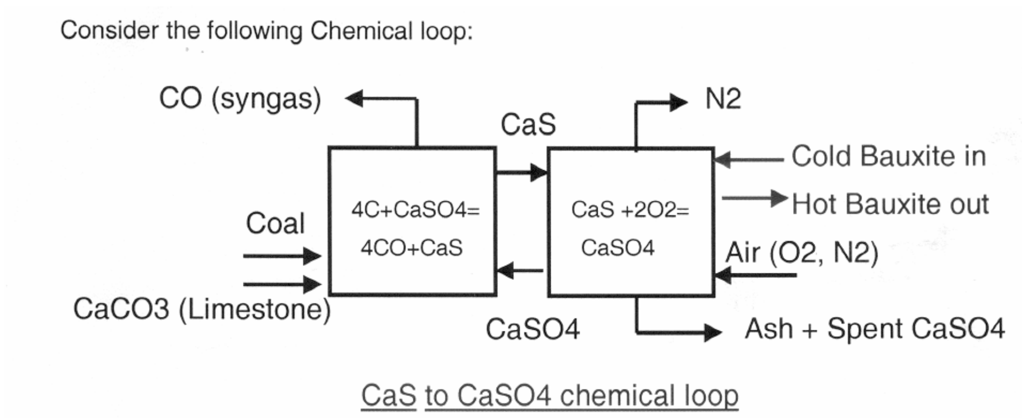

Figure 3-5: Gasification of Coal with $CaSO_4$ as Oxygen Donor and Oxidation of CaS with Air to Form $CaSO_4$
Source: Alstom

In order to speed up gasification reactions between two solids, the oxygen donor and the coal, a fraction of the product gas is recirculated, and a small amount of steam is injected into the reducer reactor. Additional chemical looping is used to calcine limestone, $CaCO_3$, decomposing it to calcium oxide (CaO) and CO_2 in one reactor, and transport CaO to another, where it captures CO_2 after the stream is steam shifted. (Figure 3-6).

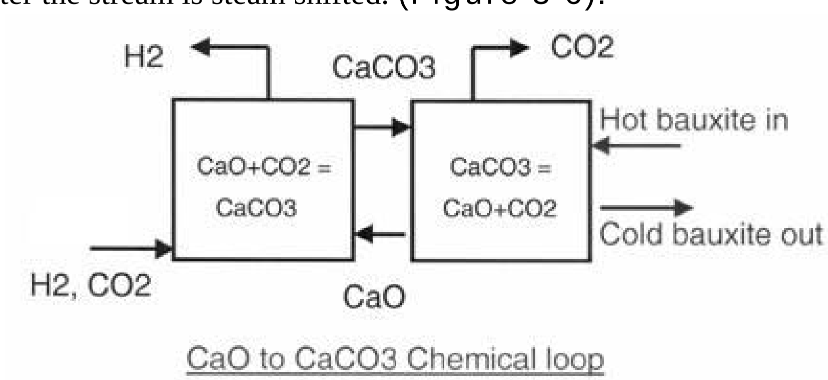

Figure 3-6: CO_2 Capture by CaO from Syngas and $CaCO_3$ Calcination[32]
Source: Alstom

To maintain the required temperature (2000ºF) for the gasification reactions and for the calcination of the limestone, thermal looping is used. This is a regenerative heat exchange process with pebbles of some mineral, such as bauxite. The pebbles are pneumatically transported and cycled between a high temperature exothermic oxidizer-, and an endothermic reducer-reactor. The reactors are fluidized beds in which the oxygen donor minerals are carried over and separated from the gas stream by cyclone precipitators, while the larger heat exchanger pebbles are drained from the bottom of the bed.

Chemical looping is an advanced technology in early development. Results of laboratory and pilot scale experimental studies on chemical looping gasification carried out under DOE sponsorship by Alstom and reported by Bozzuto, et al, and Marion, et al[33], show promise of successful development leading to demonstration stage within the next 10 to 15 years. It is estimated that successful development to commercial stage of chemical looping gasification promises IGCC plant efficiency improvement by about 2.5 percentage points, reductions in total project cost by about $130 million, and in cost of electricity by $3/MWh.[34]

Advanced CO_2 Compression

> **Compression**
> *The power necessary to compress CO_2 coming from a pulverized coal power plant would require approximately 8 percent of the plant output.*

CO_2 compression represents a large fraction of the cost penalty for any carbon capture and storage (CCS) system because compressors require significant capital and enormous amounts of power that significantly increase power plant operating costs. The CO_2 compressor power required for a pulverized coal power plant is approximately 8 percent of the plant rating. A 1000-MW PC plant would consume 80 MW of the plant output, and cost around $110 million for the compressor equipment alone. The CO_2 compressor power required for an IGCC power plant is approximately 5 percent of the plant rating. A 600-MW PC plant would require 30 MW, or 40,000 hp, at an estimated $40 million for the compressor equipment alone. Both of these values are based on current estimates of the state-of-the-art integrally-geared turbo compressor at nominal discharge pressure of 1200 psia, and do not include installation costs at an estimated 35 percent increment. The costs also represent a claimed 60 percent savings over two-casing, inline centrifugal compressors.

The consensus is that compressors will be used to compress the gas mixture to a level at which all its constituents are fully supercritical and then to apply pumps to raise the mixture to the pipeline levels of 2200 psia. CO_2, itself, is supercritical at 1070 psia, but the impact of impurities can raise this value to 1500-1600 psia (100-110 bar).

These machines are so expensive, in part, because the overall pressure ratio is 100:1, and, in part, because CO_2 requires stainless steel construction due to the presence of water vapor. But by far the most significant impact on cost is an aerodynamic design that limits the design pressure ratio per stage on heavier gases such as CO_2.

Standard turbo machinery design practice is to limit the inlet flow Mach number (#) to less than 0.90 at the inducer blade tip, in effect limiting the tip speed of the stage. The Mach # itself is a function of molecular weight, and therefore the effect is more pronounced on the heavier-than-air

CO_2. This varies somewhat between open and shrouded impeller designs, but the effect is that the tip speed limitation causes a pressure ratio per stage limitation of approximately 1.8 to 2.0:1 on CO_2. At these stage pressure ratios, eight stages of compression are typically required to reach an overall pressure ratio of 100:1.

This issue is further complicated by the need to intercool the CO_2 between each compression stage. The heat of compression associated with these stage pressure ratios is approximately 200°F, which, as an inlet to the next stage, is too hot to achieve good efficiency, but lacks the thermal driving force for cost-effective heat exchanger selection. It is also of insufficient quality to be of practical use elsewhere in the process. The only option is to reject virtually all the compressor electrical input power through cooling towers or heat exchangers, themselves a significant capital and installation expense.

Further, the intercooler selection is made more difficult by the need for low pressure drop designs and the need to use low-effectiveness 304 stainless steel construction for corrosion resistance. Air cooled heat exchangers, often required in arid climates, exacerbate the problem with generally lower approach temperatures and require substantial fan horsepower, often overlooked in the compressor power evaluation.

Advanced compressors under development are:

- Multi-stage Integrally-Geared Compressor Designs – This class of design features individual compressor stages driven by a common bullgear. The stages are typically mounted on either end of individual pinions, which allows for improved specific speed machining. One particular design, a MAN Turbo 20,000 hp, eight-stage, four-pinion, seven-intercooler, state-of-the art integrally-geared CO_2 compressor, is capable of a pressure ratio of 143:1.
- Two-Casing Multistage Inline Designs – This class of design features individual compressor stages mounted on a common shaft, driven through an external gearbox. The stage pressure ratio would be lower at approximately 1.6:1 per stage, requiring nine or 10 stages configured in two casings to achieve the 100:1 pressure ratio. Intercooling is used, but normally after every third or fourth stage. This is effective, but less efficient than cooling after each stage as in the integrally-geared approach.
- Southwest Research Institute (SwRI)/Dresser-Rand – DOE/National Energy Technology Laboratory (NETL) – SwRI will evaluate a variety of approaches to reduce compression power requirements by 20-40 percent using a variety of approaches to include isothermal compression and partial or complete CO_2 liquefaction as part of the FutureGen development program. The isothermal approach is considered conservative and has been applied on other gas compression services, but it has not yet been optimized for an IGCC environment. The liquefaction approaches attempt to replace some or all the compression approaches with liquid pumps, at a substantial reduction in power requirements, but they do require integration with the air separation unit.
- University of California (UC) Irvine – DOE/NETL – In another development effort in support of FutureGen, UC Irvine is under contract to perform full system studies to evaluate the impact of CO_2 capture on advanced coal based power systems. The major thrust of this effort is to evaluate concepts for improving turbine performance that will lead to overall improvement in plant performance. In addition,

various concepts for CO_2 compression for a fully integrated power plant will be assessed. The performance of various advanced CO_2 compression technologies will be compared to a baseline CO_2 compression case using the baseline CCS system.

- Ramgen Power Systems – DOE/NETL – In a third FutureGen-related development program, Ramgen is developing a CO_2 compressor technology that has the potential to achieve a 10:1 pressure per stage, resulting in a two-stage, integrally-geared 100:1 design. The approach uses a well known supersonic aircraft inlet system technology that can achieve very high stage efficiency and very high pressure ratio, simultaneously. Ramgen has suggested a 65 percent reduction in capital cost at 1/20th the physical size.

  The input electrical energy is approximately the same as the conventional turbo designs, but with stage discharge temperatures at this compression ratio of 450-500°F, 80 percent of the input energy can be recovered as useable heat. If recovered as electrical energy, this can reduce the power consumption by 25-30 percent. Of particular importance is that the inlet flow Mach # limitation is not applicable to shock wave compression. This decoupling releases Ramgen from this restriction and could provide a major cost reduction.

CONCLUSIONS

- Expedited demonstration of first-generation technologies for CO_2 capture is needed. Streamlining this process so the research proceeds from laboratory pilot to demonstration phase is necessary so these technologies will be available to meet future climate change regulations.
- Given the magnitude of the challenges associated with CO_2 reduction and capture, RD&D is needed on a wide range of new concepts and technologies that may provide economic solutions for carbon management.
- For advanced combustion, most opportunities for significant improvement are found in the capture process itself. For IGCC, the capture process is expected to be more efficient (compared to PC), but there are opportunities for improving the overall generation efficiency through enhanced integration between the gasification and power generation areas of the plant, better heat recovery, and through improvements in the production of oxygen in the air separation unit.
- More work should focus on demonstrating advanced technologies for CO_2 compression systems that lower the capital cost and energy requirements. Compression is expected to consume up to 8 percent of the electricity produced by a power plant and is common to nearly all CO_2 capture requirements. Improved compression systems would enhance the cost effectiveness of CO_2 capture for carbon capture systems currently being considered.
- Designers of CO_2 recovery systems should evaluate the use of waste heat recovery from the CO_2 compression systems to improve process efficiency. The effective use of the waste heat required from interstage cooling of the CO_2 during compression will improve the overall efficiency of both flue gas treatment systems for combustion-based systems and treatment of syngas for IGCC systems.

- FutureGen is a vital program and the industry looks forward to its continued development. It is such a strong model that a case can be made for a parallel program aimed at development of zero emission technologies for coal combustion plants that will also produce strong benefits domestically and internationally.
- Government has an important role in development and commercialization of energy technologies. Given the global interest in carbon capture technologies, it will be important for U.S. industries to be at the center of these important technological developments. Developing the technologies to improve efficiency and become the building blocks of tomorrow's energy systems will also enhance U.S. energy security.

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SECTION FOUR

Carbon Management for Coal to Products

FINDINGS

- Development of a coal conversion industry in the U.S. that makes use of the nation's vast and abundant domestic coal resources would enhance national energy and economic security objectives, providing a hedge against foreign oil dependency, global competition for energy reserves and associated security risks.
- Alternative liquid fuels derived from coal can be used in existing vehicle and air transport fleets with little or no modification, and delivered to end users via existing distribution infrastructure.
- Poly-generational coal conversion plants can produce multiple products to meet growing U.S. demand for electricity and transportation fuels, as well as demand for chemicals and fertilizers.
- Coal to liquids (CTL) fuels are ultra clean – low in sulfur, nitrogen, particulates and aromatics – and can outperform petroleum-derived fuels in cold weather.
- The use of carbon capture and storage (CCS) technologies can minimize emissions from CTL plants and result in life-cycle greenhouse gas emissions comparable to or lower than conventional petroleum-derived transportation fuels.
- Alternative liquid fuels can be produced from coal alone or coal mixed with other carbon bearing feedstocks, such as biomass.
- Historical efforts to develop a U.S. CTL industry have been constrained by low oil prices. CTL is cost competitive with $45 per barrel oil, including the cost of CCS.

Introduction

Coal conversion is a clean coal technology. It uses mature, commercially demonstrated and proven processes to gasify or liquefy coal to produce a variety of energy products. Poly-generational coal conversion plants can produce pipeline quality natural gas, liquefied petroleum gas (LPG), hydrogen, transportation fuels – including gasoline, diesel fuel and a range of chemical products such as ammonia, methanol, acetic acid and olefins (which are building blocks for plastic material production), as well as electricity. Figure 4-1 illustrates the many products that can be produced from the coal conversion process. Any product made from oil can be made from coal.

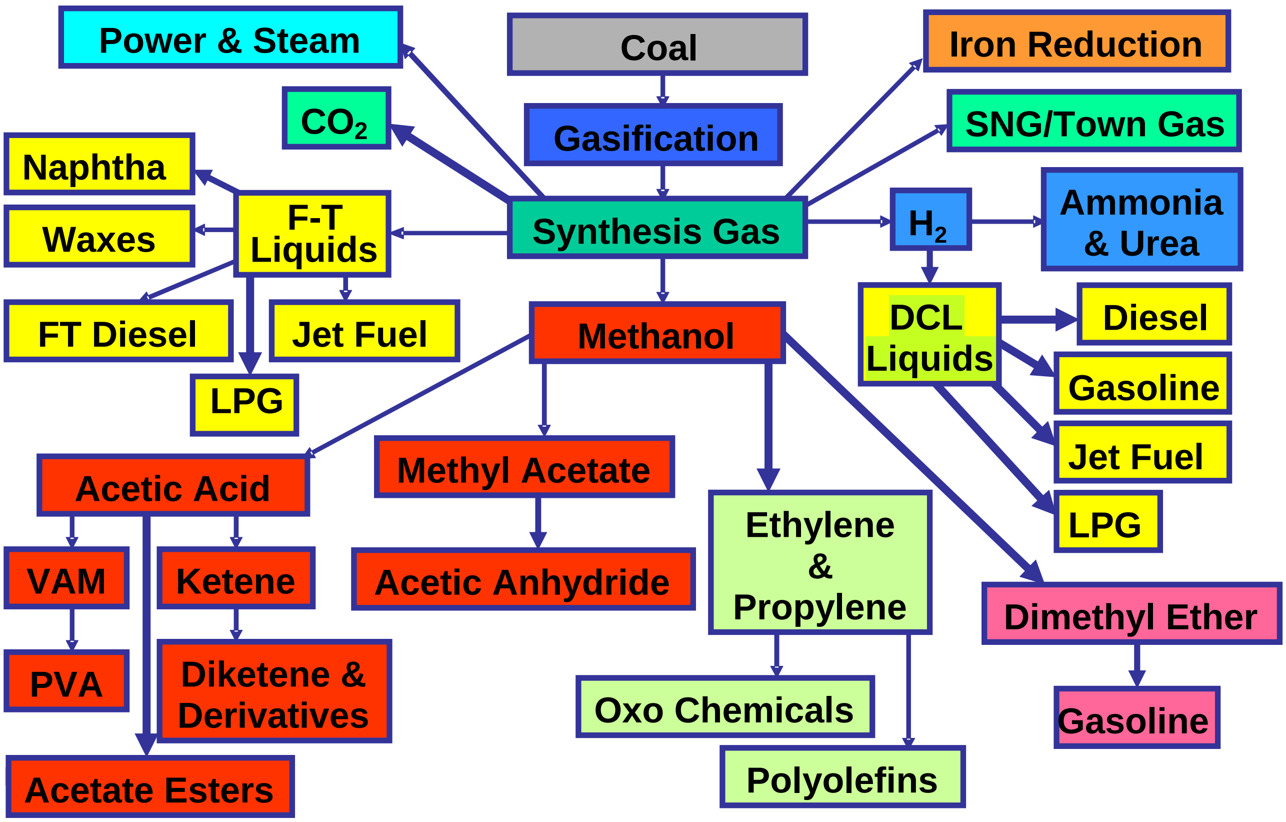

Figure 4-1: Coal Conversion to Multiple Products [35]
Source: Eastman Chemical, modified

Between 1850 and 1950, before development of the modern petrochemical industry in the mid-20th century, coal was the main feedstock for chemical production worldwide. During World War II, coal-derived fuels were used in Germany for aviation and transportation fuel needs. South Africa has been meeting much of its liquid fuels and petrochemical requirements through coal liquefaction since 1955. Today, the high cost of crude oil and technological advances in coal gasification and liquefaction are encouraging a global renaissance of coal-based chemical and fuels production. CTL projects are proposed or under way in most major coal-producing countries, including China, India, Mongolia, the Philippines, Indonesia, Australia, Germany and South Africa.

In years past, the U.S. has constructed a number of CTL plants. These facilities, since shut down in response to declining oil prices, have demonstrated the technical and performance viability of liquid fuels. With nearly 500 billion tons of demonstrated reserves[36], the U.S. has an equivalent of 992 billion barrels of CTL potential[37], based on production of two barrels of CTL fuel per ton of coal. By comparison, crude oil reserves in the Middle East are estimated at 739 billion barrels[38], including production from Saudi Arabia, Iraq, United Arab Emirates, Kuwait and Iran.

Global demand for petroleum products is expected to increase 40 percent by 2025, driven largely by the high-growth economies in China and India. China is pursuing strategic interests with oil-producing nations worldwide. Competition for global energy resources will intensify in the coming years.

In 2005 and 2006, the U.S. imported 60 percent of its petroleum products[39]. U.S. petroleum imports totaled $5.35 billion for the two years[40]. This transference of wealth, combined with the additional financial and human resources needed to support defense efforts, detracts from U.S. economic growth prospects.

A recent report by the World Coal Institute[41] noted that "converting coal to liquid fuels provides ultra-clean, sulphur-free products, low in aromatic hydrocarbons (such as benzene), and offering significant reductions in vehicle emissions such as oxides of nitrogen, particulate matter, volatile organic compounds and carbon monoxide. They are readily bio-degradable and non-toxic. Fuel consumption is lowered, reducing emissions of end-use carbon dioxide." The coal liquefaction process is inherently carbon capture ready; the end products produced from CTL are environmentally superior to petroleum-derived fuels.

Refined CTL fuels have been used successfully as transportation fuels in Germany and South Africa without requiring any major modification to engines. More recently, gas-to-liquid (GTL) fuels (similar to CTL fuels) have been used successfully in cars, buses, trucks and jet airplanes in normal and cold winter climates.

The time is right to spend U.S. dollars at home to develop American jobs using American resources for an environmentally responsible fuel that works in today's vehicles.

Coal Conversion Technology

Coal and petroleum both contain carbon and hydrogen. Coal is rich in carbon, but deficient in hydrogen. The hydrogen/carbon (H/C) atomic ratio of coal is around 0.3 to 0.9 depending on the type of coal. Liquid fuels (gasoline and diesel) have a higher H/C ratio in the range of 1.4 to 2.0. Therefore, the conversion of coal to liquid fuels requires a significant increase in the H/C ratio. This change can be accomplished through hydrogen addition or carbon removal.

Direct Coal Liquefaction (DCL)

Direct coal liquefaction (DCL) is a hydrogen addition process in which the coal structure is broken down into smaller molecules through thermal cracking in the presence of a catalyst and hydrogen. This process is very similar to the process used for hydrocracking of petroleum residual practiced in the refining industry. Sulfur, nitrogen and ash are removed in direct coal liquefaction and can be recovered as by-products.

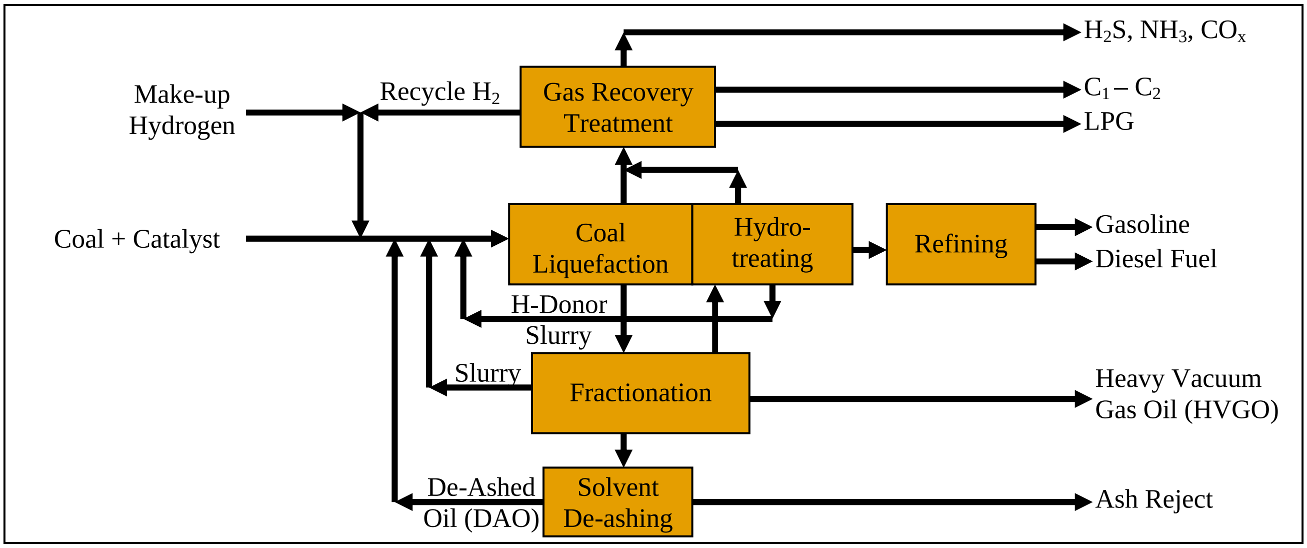

Figure 4-2: Simplified Block Flow Diagram of Direct Coal Liquefaction
Source: Headwaters, Inc.

Indirect Coal Liquefaction (ICL)

Indirect coal liquefaction (ICL) is a carbon rejection process in which the H/C atomic ratio is increased to around two. This increase is accomplished in two steps – 1) gasification of the coal to produce syngas (a mixture of hydrogen and carbon monoxide) followed by 2) Fischer-Tropsch (FT) synthesis reaction to produce straight-chain hydrocarbons (paraffins). Depending on the type of catalyst and process conditions used, the proportion of intermediate products (fuel gas, LPG, naphtha, middle distillates and paraffin wax) varies.

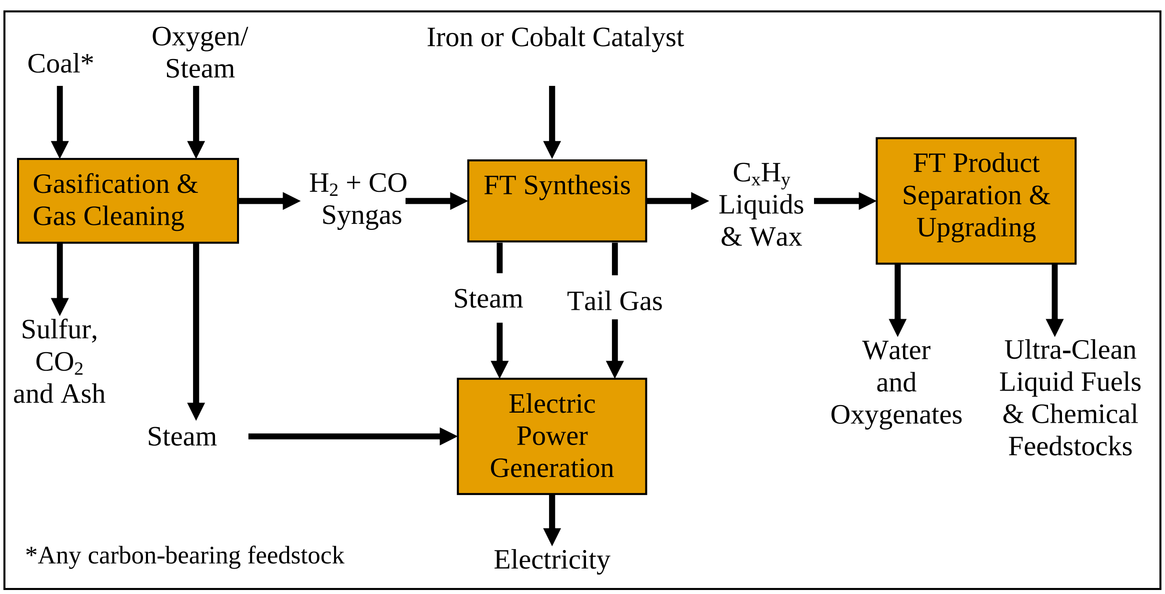

Figure 4-3: Simplified Block Flow Diagram of Indirect Coal Liquefaction
Source: Headwaters, Inc

Hybrid Coal Liquefaction (DCL/ICL)

The Hybrid CTL process configuration is a plant design in which DCL and ICL technologies are integrated to take advantage of feedstock flexibility, product blending and energy optimization. Syngas produced from the gasifier is fed to the FT synthesis reactor to produce straight-chain hydrocarbon products. The hydrogen in the FT tail gas then is recovered to meet the needs of the DCL and downstream product upgrading units. The remaining FT tail gas is sent to the power block along with steam generated in the ICL unit to meet the power requirement of the entire facility.

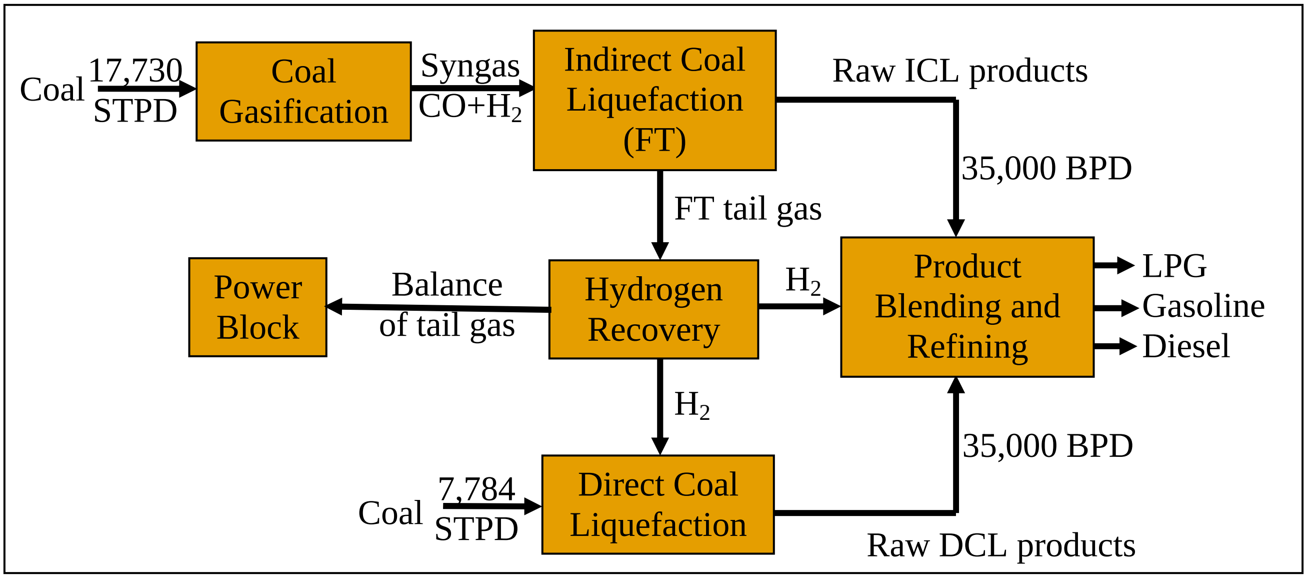

Figure 4-4: Simplified Block Flow Diagram of Hybrid Coal Liquefaction
Source: Headwaters, Inc

Comparison of CTL Technologies

Figure 4-5 compares the key operating parameters for direct, indirect and Hybrid CTL technologies. In each case, the data was calculated for a 70,000 barrel per day (bpd) CTL plant processing Illinois No. 6 bituminous coal (12,862 Btu/lb on a dry basis). The coal is gasified by slurry-fed, entrained-flow, water-quenched gasifiers. The DCL technology consists of two-stage ebullated-bed reactors using an iron catalyst. The ICL technology consists of slurry-phase reactors with an iron catalyst. In the "ICL Recycle" option, 80 percent of the FT tail gas is recycled back to FT synthesis and 20 percent is combusted in a gas turbine. In the "ICL Once-Through" option, 100 percent of the tail gas from FT synthesis is combusted in a gas turbine. The Hybrid plant integrates equally sized DCL and ICL Once-Through plants. Total energy input is calculated based on higher heating value of coal feedstock plus 8.987 MMBtu per MWh of imported electricity. Total energy output is calculated based on the higher heating values of liquid fuel products plus 3.412 MMBtu per MWh of exported electricity.

Plant Type	DCL	ICL Recycle	ICL Once-Through	Hybrid
Coal Consumption (STPD dry basis)				
Coal Feed Rate to DCL	15,568	0	0	7,784
Coal Feed Rate to Gasifier	7,476	32,305	37,974	17,730
Total Coal Feed Rate	23,044	32,305	37,974	25,514
Liquid Product Capacity (BPD)				
Diesel	45,812	47,687	47,687	46,750
Naphtha	18,863	22,313	22,313	20,591
LPG	5,325	0	0	2,660
Total	70,000	70,000	70,000	70,000
Electric Power Capacity (MW)				
Gross	0	1,419	2,214	725
Parasitic	282	1,018	1,077	680
Net Export	0	399	1,139	45
Net Import	282	0	0	0
Energy Balance				
Total Energy Input (MM BTU/D)	653,057	831,012	976,855	656,323
Total Energy Output (MM BTU/D)	392,776	402,001	462,559	385,490
Overall Thermal Efficiency (%)	60.14	48.37	47.35	58.73
Coal Input (MM BTU/BBL product)	8.47	11.87	13.96	9.38
Product Yield (BBL of product /ST dry coal)	3.04	2.17	1.84	2.74
Carbon Balance				
Carbon in Product (% of input C)	53	34	29	45
Carbon in Slag/Ash (% of input C)	1	1	1	1
Carbon in CO_2 (% of input C)	46	65	70	54
Plant CO_2 Generation (lbs/bbl product)	783	1,557	1,972	1,010
Economics				
Relative Capital Cost	1.00	1.10	1.25	1.03

Figure 4-5: Comparison of CTL Technologies
Source: Headwaters, Inc

Coal Consumption

The DCL plant has the lowest coal consumption, followed by Hybrid, ICL Recycle and ICL Once-Through plants. Approximately 32 percent of the coal used in the DCL plant can be lower-grade coal; the other 68 percent should be low-ash bituminous or sub-bituminous coal. The Hybrid plant can be designed to handle up to 70 percent lower-grade coal and the ICL plants can be designed to handle up to 100 percent lower-grade coals.

Product Mix

All four CTL technologies can produce a product mix of approximately two-thirds diesel and one-third naphtha. The DCL and Hybrid technologies produce a small amount of LPG. The ICL plants theoretically can be designed to produce a product mix in the range of 65 to 80 percent diesel and 20 to 35 percent naphtha. Some LPG also could be recovered, however, in the above ICL plants the LPG is left in the FT tail gas and delivered to the power block because of its high olefin content. Although not indicated in the table, all the CTL plants could be designed to shift about 30 percent of their product mix into production of jet fuel.

Electric Power Generation

The DCL plant is a net importer of electric power. A power block could be added to make the plant self sufficient if the coal gasifier were expanded to provide additional syngas. The ICL plants generate significant excess electricity because of the large amounts of steam and FT tail gas generated. The Hybrid plant is self sufficient in electric power with a small amount of export power available.

Thermal Efficiency

At 60 percent overall thermal efficiency, the DCL plant is approximately 24 to 27 percent more efficient than the ICL plants. The Hybrid plant, at 59 percent, is very close to the same efficiency as the DCL plant. The specific coal consumption (million Btu per barrel of product) and product yield (barrels of product per short ton of dry coal) also indicate the thermal efficiency advantage of the DCL and Hybrid plants over the ICL plants.

Carbon Balance

Carbon utilization is highest in the DCL plant, with 53 percent of the input carbon ending up in the liquid fuel products. The Hybrid plant is second with 45 percent, and the ICL plants are 34 and 29 percent. Only about 1 percent of the input carbon ends up in the slag and char of the gasifiers. The remainder ends up as carbon dioxide (CO_2). The ICL plants generate 2.0 to 2.5 times more CO_2 than the DCL plant and 1.5 to 2.0 times more than the Hybrid plant. Approximately 80 percent of the CO_2 generated in the ICL and Hybrid plants and up to 100 percent of the CO_2 in the DCL plant can be easily recovered in concentrated form using acid gas removal systems as discussed in the following section. In a carbon constrained world, this can be significant.

Comparison of CTL End Product Characteristics

Figure 4-6 summarizes some of the typical end product characteristics of diesel fuel and naphtha that could be produced in DCL, ICL and Hybrid plants. The Hybrid plant ends up being an average of the DCL and ICL products. This is an advantage because the Hybrid plant can produce high-quality gasoline and diesel fuel with minimal refining. The DCL stand-alone plant produces high-octane gasoline but marginal-cetane diesel, and the ICL stand-alone plant produces high-cetane diesel and low-octane naphtha, which would require significant refining to make gasoline.

	DCL	ICL	Hybrid	Spec/Typical
Diesel				**Conventional ULS Diesel**
Specific gravity	0.865	0.780	0.821	0.82-0.85
Cetane	42-47	70-75	56-61	>40
Sulfur (ppm)	<5	<1	<3	<15
Aromatics (%)	4.8	<4	<4.4	<35
Higher heating value (BTU/Gal)	138,100	129,800	133,950	138,700
Naphtha				**Conventional Gasoline**
Specific gravity	0.764	0.673	0.717	0.72-0.78
Octane (RON)	>100	45-75	75-95	85-95
Sulfur (ppm)	<0.5	Nil	<0.25	<30
Aromatics (%)	5	2	3.5	<27
Higher heating value (BTU/Gal)	133,000	116,690	124,845	124,800

Figure 4-6: Comparison of CTL End Products

DCL fuel has high density resulting in high energy content per gallon, while ICL fuel has low density resulting in low energy content per gallon. Hybrid fuel is midway between DCL and ICL and will have a density and energy content per gallon close to that of conventional petroleum-derived fuels. Thus customers using Hybrid fuels are likely to see comparable performance in miles per gallon compared to conventional petroleum-derived fuels.

All the CTL technologies can produce ultra-low sulfur, ultra-low nitrogen and low aromatic fuels. All the fuels can outperform petroleum-derived fuels in cold weather.

Coal can be used to produce other ultra-low-sulfur alternative fuels such as methanol, di-methyl ether (DME), methanol-to-gasoline (MTG gasoline), propane, synthesis natural gas (SNG) and hydrogen. Figure 4-7 compares the typical characteristics of these fuels.

	Methanol	DME	MTG Gasoline	Propane	SNG	Hydrogen
Carbon (wt %)	37.5	52.1	86.5	82	75	0
Hydrogen (wt %)	12.6	13.1	13.5	18	25	100
H/C atomic ratio	4	3	1.86	2.67	4	∞
Specific gravity	0.796	0.668	0.731	0.508	0.424	
Higher heating value (BTU/gal)	64,250	69,428	124,800	91,300	21,938*	NA

*Natural gas compressed at 2400 psi.

Figure 4-7: Comparison of Other Alternative Fuel Products
Source: Headwaters, Inc

Out of the alternative fuels listed in the above table, only MTG gasoline can be used in existing engines without modification and performs as well or better than conventional petroleum-derived gasoline. Even with modifications, the other alternative fuels will deliver significantly lower fuel efficiency (miles per gallon) compared to conventional petroleum-derived gasoline or diesel, as can be seen by the energy content on a Btu/gallon basis.

Commercial Status

DCL was developed in Germany in 1913 and later used to produce aviation fuels during World War II. From 1976 to 2000, the U.S. federal government invested approximately $3.6 billion on improving and scaling-up direct coal liquefaction[42]. Much of the equipment used in DCL has been commercially proven for upgrading heavy oil. The first full-scale commercial DCL plant is under construction in China. It has a rated capacity of 20,000 barrels per day and is scheduled to start up in early 2008. Additional projects are being studied or planned in China, India and Indonesia.

ICL was developed in Germany in 1923 based on work by Drs. Franz Fischer and Hans Tropsch. During World War II, the technology was used by Germany to produce 17,000 barrels per day of liquid fuels from coal. In 1955, Sasol constructed an ICL plant at Sasolburg, South Africa. Additional plants were constructed at Secunda, South Africa. Today, Sasol produces the equivalent of 150,000 barrels per day of fuels and petrochemicals using its ICL technology. ICL projects are being studied or planned in the United States, China, Germany, Netherlands, India, Indonesia, Australia, Mongolia, Pakistan and Canada.

A 2,600 bpd coal-based methanol-to-gasoline demonstration project is under construction in China and will start up in 2008. Successful startup and operation will lead to construction of a 26,000 bpd plant. The technology originally was demonstrated in New Zealand on a scale of 14,500 bpd from 1985 to 1995.

Figure 4-8 lists CTL projects that have been publicly announced in the United States. Dozens of additional projects are being studied, but have not been publicly announced.

State	Developer	Coal Type	Capacity (BPD)
MT	DKRW Energy	Bituminous	22,000
ND	Headwaters Energy Services, Great River Energy and North American Coal	Lignite	30,000
WY	DKRW Energy	Bituminous	13,000
OH	Baard Energy	Bituminous	35,000
IL	Rentech	Bituminous	2,000
IL	American Clean Coal Fuels	Bituminous	25,000
PA	WMPI	Anthracite	5,000
WV	Mingo County	Bituminous	10,000
MS	Rentech	Bituminous	22,000
LA	Ligfuels (formerly Synfuel Inc.)	Lignite	125,000
AK	US DOE	Sub-bituminous	14,640
AK	ANRTL and China Petroleum Corp	Sub-Bituminous	80,000

Figure 4-8: Planned Coal to Liquids Projects in the U.S.

Estimates of the potential for CTL vary widely. On the high side is the Southern States Energy Board[43] which believes CTL production could exceed 5 million barrels per day. The National

Coal Council envisions 2.6 million barrels per day by the year 2030. The Energy Information Administration (EIA) reference case forecast projects CTL production at about 800 thousand barrels per day by 2030. This forecast assumes real oil prices increase 1.6 percent per annum over the forecast period. If real prices rise 3.6 percent per annum in their high oil price scenario, CTL production more than doubles to over 1.6 million barrels per day.

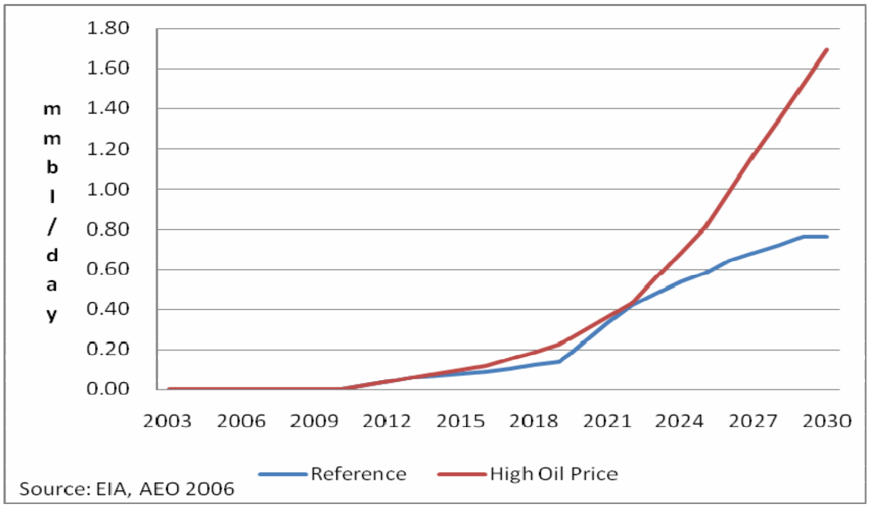

Figure 4-9: EIA Forecasts of U.S. Coal to Liquids Production
Source: Energy Information Administration

CTL and Carbon Management:
Life-Cycle Greenhouse Gas Emissions

A life-cycle greenhouse-gas (GHG) emissions inventory for ICL diesel was prepared for the U.S. Department of Energy National Energy Laboratory (NETL) in June 2001. This study compared the emissions for ICL (with recycled FT tail gas) diesel with conventional petroleum diesel delivered to Chicago, IL. Some of the results from that study are summarized in Figure 4-10.

Feedstock	Grams of CO_2-equivalent Emissions per Mile in a Sport Utility Vehicle				
	Extraction/ Production	Conversion/ Refining	Transportation/ Distribution	End Use Combustion	Total Fuel Chain
IL#6 Coal (ICL without CCS)	26	543	1	368	939
IL#6 Coal (ICL with CCS)	26	94	1	368	490
WY Sweet Crude Oil	23	74	8	363	468
Arab Light Crude Oil	35	81	26	367	509
Alberta Syncrude	32	104	10	370	516

Source: Marano, John J., Ciferno, Jared P. "Life-Cycle GHG Emissions Inventory for F-T Fuels", NETL, June 2001

Figure 4-10: Full Life-Cycle GHG Emissions for FT and Petroleum Diesel Scenarios

Figure 4-10 compares ICL diesel derived from Illinois No. 6 bituminous coal (with and without CCS) with conventional diesels derived from Wyoming sweet crude oil, Arab light crude oil and Alberta syncrude produced from tar sand. The table shows that ICL with CO_2 carbon capture can achieve total life-cycle greenhouse-gas emissions (far right column) comparable to or lower than conventional petroleum diesel.

Life-cycle GHG emission inventories have not been completed on direct and Hybrid coal liquefaction technologies. However, based on the fact that these technologies have lower plant CO_2 emissions than indirect coal liquefaction and the CO_2 is in concentrated form, it can be assumed that direct and hybrid technologies will have lower life-cycle GHG emissions than conventional petroleum diesel.

Co-Processing Coal and Biomass for Carbon Management

There is growing interest in using coal and biomass (agricultural and forestry by-products) together to reduce net carbon dioxide emissions. This is achieved because biomass is considered a renewable resource and a zero net carbon dioxide emitter.

The co-processing of coal and biomass would allow a much greater scale of liquid fuel production than an exclusive reliance on biofuels. Cost reduction targets could be reached much sooner than with conventional biofuel options, such as cellulosic ethanol.

Biofuel Carbon

Biofuels are considered carbon neutral because the carbon in biofuels was recently extracted from atmospheric carbon dioxide by growing plants as part of a natural cycle, so burning it does not result in a net increase of carbon dioxide in the atmosphere.

Co-processing coal and biomass could also produce a vehicle fuel with lower greenhouse gas emissions than conventionally derived petroleum-based fuel or corn-based ethanol. A recent study commissioned by Baard Energy from Idaho National Laboratory found that on a “wells to wheels” basis, diesel produced with a feedstock of 70 percent coal and 30 percent biomass, in a facility utilizing carbon capture and storage, would emit 46 percent less greenhouse gas emissions than petroleum diesel.[44]

The co-processing of coal and biomass in commercial gasification plants is being done in Europe in the range of 80 to 90 percent coal and 10 to 20 percent biomass. It is speculated that up to 30 percent of the feed mix could be in the form of biomass; however, there are economic and logistic issues to consider. Biomass is a bulky material with low density, high water content and is expensive to transport and pre-process for gasification. It also tends to be seasonal and widely dispersed. Thus biomass is likely to remain a small percentage of the total feed in CTL plants.

CONCLUSIONS

- Coal to products (CTP) technologies can produce a range of fuels and chemicals while generating significant amount of by-product electricity. CTP technologies can produce high quality liquid fuels, such as diesel, jet fuel and gasoline with virtually no sulfur or particulates. Price volatility of oil and natural gas, however, is a key barrier to adoption of CTP technologies.
- Government support through Department of Defense for CTP deployment should be encouraged for the following reasons:
    - To create a secure source of domestic fuel production in the event that foreign oil supply lines are disrupted, and
    - To advance the development of CTP gasification technologies which will have co-benefits in advancing essentially similar technologies for carbon capture applications at power plants.
- CTP can also produce pipeline quality natural gas that can be shipped through existing natural gas pipeline infrastructure. Producing gas from coal may avoid creating another dependency on foreign energy.
- Long-term government contracts for CTP fuels and other government-private partnerships can mitigate risk and reduce economic barriers significantly. This will help attract the capital resources needed to build and grow CTP industries.
- CO_2 emissions resulting from CTP or synthesis natural gas production should not be considered a serious constraint because the same technologies discussed in this report for capturing and storing CO_2 are also applicable to CTP technologies.
- Co-processing biomass with coal, in combination with carbon capture and storage, may produce benefits that have significantly lower greenhouse gas profiles than conventional products, such as petroleum-based diesel or corn ethanol.
- The use of CCS technologies can minimize CO_2 emissions from CTP production plants and result in life-cycle greenhouse gas emissions comparable to, or lower than, conventional petroleum-derived transportation fuels.

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SECTION FIVE

Carbon Dioxide Capture and Storage

FINDINGS

- Geological storage of carbon dioxide (CO_2) holds great promise. Focused research and development is needed in a number of areas to make it cost effective and sufficiently reliable to ensure public support and acceptance. Key areas for technology development include:
  - Aggressively developing a robust portfolio of demonstration projects for CO_2 storage to provide solid empirical data for a range of geologic formations and structures.
  - Developing and demonstrating measurement, monitoring and verification (MMV) instrumentation, systems and methodologies for large-scale, long-term storage.
- CO_2 transport via pipeline is a mature technology. The safety record of this activity is excellent. At scale, costs are expected to be a small part (<10 percent) of the overall capture and sequestration costs. Key developments for transport systems are the continued advancement of technologies to monitor and ensure pipeline integrity and safety.
- Natural terrestrial sequestration rates will likely only offset a fraction of total carbon emissions; however, terrestrial sequestration strategies can be implemented immediately.
- Using CO_2 to enhance oil production is a commercially proven technology and could be greatly expanded with CO_2 captured from power plants. There is also considerable potential to enhance coal-bed natural gas production with CO_2 injection.
- Other beneficial uses of power plant CO_2 include replacing current industrial consumption, producing carbonate materials, and using biological conversion. This last option appears the most promising niche application, employing genetically engineered enzymes that absorb and convert CO_2 to bicarbonate materials.
- Policy direction is needed in regard to rules and regulations for CO_2 injection to mitigate concerns about long-term storage confidence and liability.

> **Siting**
>
> *The same kinds of geological setting where oil and gas deposits are found are suitable for CO_2 storage because they form impenetrable seals that are essential for trapping CO_2 underground.*

Storage and Monitoring

Today, 22 billion metric tonnes of CO_2 are emitted annually into the atmosphere from manmade sources. Worldwide, approximately one-third of emissions are from electricity production, one-third from transportation, and the rest are from industrial uses such as heating. Oil, coal and natural gas are the primary sources of these emissions, and these fossil fuels provide more than 85 percent of the world's energy needs.

During the next hundred years, demand for energy is expected to more than double. Reducing or offsetting CO_2 emissions from fossil fuel use is the primary purpose of carbon capture and storage (CCS) – a technology in which CO_2 is captured directly from the industrial source, concentrated into a nearly pure form and then pumped into deep geological formations far below the ground surface for long-term or permanent storage. CCS is expected to be most useful for large, stationary sources of CO_2, such as power plants, petroleum refineries, gas processing facilities and cement factories.

Carbon dioxide capture and storage is a four-step process.

1. First, the CO_2 is separated from power plant "flue gas" and concentrated into a nearly pure form.
2. It is then compressed to about 1072 psi (100 bar), where it is in a liquid form.
3. Next, it is put into a pipeline and transported to the location where it is to be stored.
4. Finally, the CO_2 is injected into a deep geological formation for long-term storage.

Much of the technology used for storing CO_2 in deep underground formations is adapted from oil and gas exploration and production technology. For example, technologies to drill and monitor wells that can safely inject CO_2 into the storage formation are available from CO_2-enhanced oil recovery (EOR). Methods to characterize a site are fairly well developed, based on oil and gas exploration and characterization of natural gas storage sites, particularly saline formation storage sites. Models are available to predict where the CO_2 moves when it is injected underground, although more work is needed to further develop and test these models, particularly over the long timeframes and large spatial scales envisioned for CO_2 storage. Monitoring of the subsurface movement of CO_2 is being successfully conducted at several sites, although, again, more work is needed to refine and test monitoring methods.

Geological Formations and CO_2 Entrapment

Geological formations suitable for CO_2 storage occur primarily in sedimentary basins – where thick accumulations of sediments have been deposited over millions of years. Rocks in sedimentary basins are composed of transported and deposited rock grains, organic material and minerals that formed after the rocks were deposited. The pore space between grains or minerals is occupied mostly by water, but occasionally oil and gas. The same kinds of geological settings where oil and gas deposits are found are suitable for geological storage. These settings are distinguished by the presence of alternating layers of rocks with different textures. Some layers consist of very fine-textured materials such as clay and silt. These form impermeable barriers, or seals, that trap oil and gas underground – and are also essential for trapping CO_2 underground. Alternating with these low-permeability layers are coarser-textured layers, consisting typically of sand, that form the reservoirs in which the oil and gas reside. These coarse-textured sand layers also can be used for underground storage of CO_2. As shown in Figure 5-1, CO_2 can be stored in oil reservoirs, gas reservoirs and saline formations (rocks filled with salty water that is not suitable for drinking, agricultural or industrial use). In addition, deep unminable coal beds also may be suitable for CO_2 storage, although this technology is not as well developed as the other options. Recent and ongoing investigations may demonstrate that volcanic rocks such as basalts also may be suitable for storage in regions where large sedimentary basins are absent (such as the Pacific Northwest region of the United States), but this research is at a very early stage.

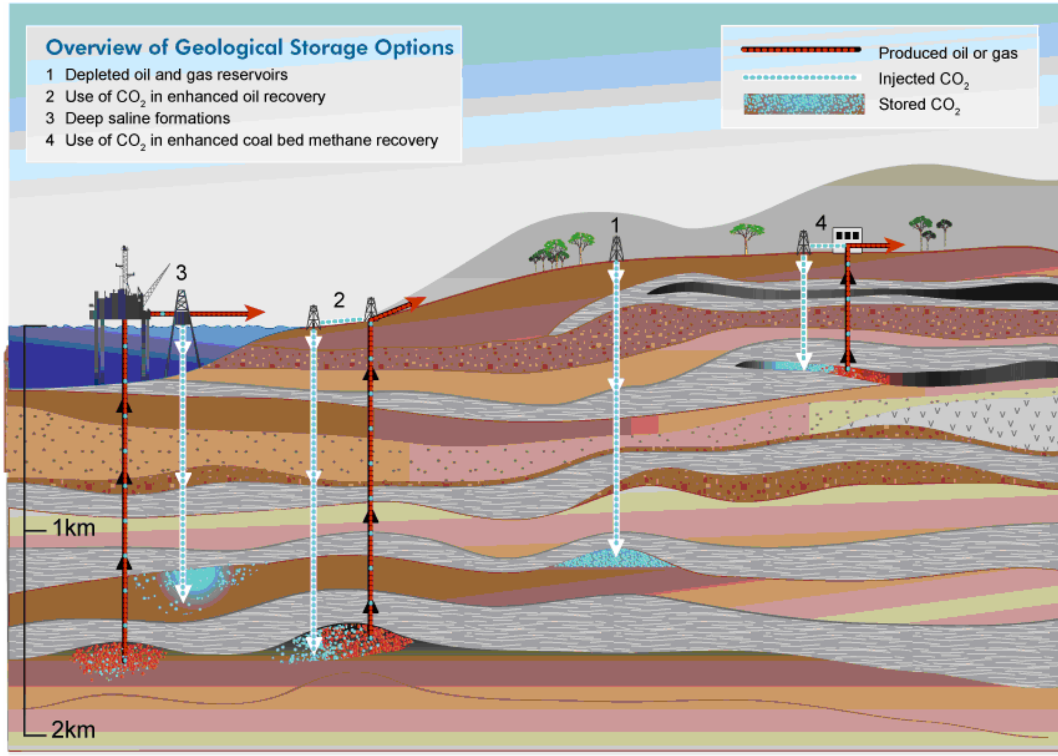

Figure 5-1: Illustration showing several options for storage of CO_2 in deep geological formations.[45]
Source: IPCC

In general, CO_2 will be stored at great depths below the ground surface, a half mile (800 meters) or more. At these depths, CO_2 is more like a liquid than a gas, allowing efficient use of underground storage space. In addition, storage security is enhanced by a number of factors, including smaller density differences between the CO_2 and in situ fluids, increased probability of multiple geological barriers between the storage formation and the ground surface, and the smaller number of old abandoned wells that penetrate the caprock of the storage formation.

The capacity for storage is large. A recent assessment by Battelle [46] estimates 3900+ $GtCO_2$ capacity exists within 230 candidate geologic CO_2 storage reservoirs in the U.S. These potential storage sites include:

- 2730 Gt CO_2 in deep saline formations
- 240 Gt CO_2 in on-shore saline-filled basalt formations
- 35 Gt CO_2 in depleted gas fields
- 30 $GtCO_2$ in deep unminable coal seams with potential for enhanced coal bed methane recovery
- 12 $GtCO_2$ in depleted oil fields with potential for EOR

Capacity

U.S. Geological storage capacity exists for several centuries of storage of CO_2 emissions from stationary sources. However, storage locations are not evenly distributed across the country.

This capacity is sufficient to store CO_2 emissions from stationary sources in the U.S. for at least several centuries at today's rates. Worldwide, the estimated capacity is also large, ranging from about 2,000 billion metric tonnes to over 10,000 billion metric tonnes. The geographic distribution of storage capacity is not uniform, with some areas having great abundance while others are not suitable. Also, storing CO_2 generated from some existing power plants may require transportation up to several hundred miles.

Three CO_2 storage projects are in operation today: the Sleipner Project offshore of Norway; the Weyburn Project in Saskatchewan, Canada; and the In Salah Project in Algeria.

- The Sleipner Project, which began in 1996, injects about 1 million metric tonnes per year of CO_2 into a saline formation offshore of Norway. CO_2 is captured from a natural gas processing plant and injected to a depth of 800 meters below the sea-bottom.
- The Weyburn Project combines CO_2-EOR with CO_2 storage. Since it began in 2000, between 1 and 2 million metric tonnes per year have been injected into an oil reservoir.
- The In Salah Project, which began in 2004, injects about 1 million metric tonnes per year of CO_2 into the water-filled part of a producing gas reservoir.

Getting Started

The three existing storage projects in total inject CO_2 at a rate equivalent to only a single 500 MW coal-fired power plant.

The total CO_2 injected by these three projects approximates the output of a single typical 500-megawatt coal-fired power plant. These projects include extensive monitoring by international research teams – monitoring which has demonstrated safe and effective storage at each site. Within five years, many more industrial-scale projects will become operational; for example, the FutureGen and Carson projects in the U.S., the Snohvit project in Norway, the Gorgon in Australia and the Miller Project in Scotland. Also, over 25 pilot projects are under way, including those sponsored by the Department of Energy through the Regional Sequestration Partnership Program. In addition to these CO_2 storage projects, use of CO_2 for EOR has been under way for more than 30 years. To enhance recovery of oil, CO_2 is injected into deep oil reservoirs and used to displace oil that would be difficult to remove by conventional methods. Although not designed for CO_2 storage, the technology for CO_2-EOR is essentially the same. In the United States, 73 CO_2-EOR operations inject up to 30 $MtCO_2$ each year. (See following discussion on EOR.)

EOR Today

In the United States, 73 operations inject a total of 30 million tons of CO_2 each year into oil reservoirs to push out oil that would otherwise not be attainable.

A recent assessment of CO_2 capture and storage by 32 authors from around the world concluded that, based on multiple evidence about the short- and long-term security of geological storage, for large-scale CO_2 storage projects (assuming that sites are well selected, designed, operated and appropriately monitored) it is likely the fraction of stored CO_2 retained will be more than 99 percent over the first 1,000 years. The expected long retention times, combined with a wealth of related experience with large-scale injection, lead these authors to conclude (Intergovernmental Panel on Climate Change (IPCC), 2005):

> "With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of

current activities such as natural gas storage, EOR and deep underground disposal of acid gas."

The results of this assessment, taken together with actual operating experience from three CO_2 storage projects with a collective operating experience of 17 years, suggests that CO_2 storage in deep geological formations can be carried out safely and reliably. However, there is still much work to be done in demonstration projects, technology development and resolving institutional issues before CCS is likely to be implemented on the large scale needed to significantly reduce CO_2 emissions into the atmosphere.

Demonstration Projects

The capacity, injectivity and containment of geological storage formations are highly site specific. Therefore, much more practical real-world experience is needed in a variety of geological environments to gain knowledge and build the confidence needed to increase and accelerate deployment of CCS. This experience can be obtained in a number of ways:

- Conduct 10 or more mid- to large-scale geological storage demonstration projects in promising storage targets, across a range of geographic environments. Phase III of the U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnerships will support seven of these demonstration projects – each injecting about 1 Mt/year over a four-year period. In addition, the FutureGen Alliance will include conducting a large-scale geological storage project over 10 years.
- Participate as a technology partner in the commercial-scale demonstration projects being carried out around the world (e.g., In Salah, Algeria; Otway, Australia; etc).
- Ensure widespread dissemination of results from all these projects directed toward a variety of stakeholders: commercial companies, research scientists and engineers, regulatory authorities, non-governmental organizations and the public. Widespread dissemination and analysis of data from these projects will provide the cost and performance information needed to build confidence in this technology.

Projects Needed

Numerous additional demonstration projects at industrial-scale are critical to successful implementation and public acceptance of carbon capture and storage.

Potential of Enhanced Oil Recovery for Carbon Storage

CO_2-EOR can provide a valuable near-term option for storing significant volumes of industrial CO_2 emissions. Fully realizing the benefits of this option will require establishing a constructive set of incentives and investments in technology that integrates EOR and carbon storage.

Oil Reservoirs as Sites for Storing CO_2

Large oil reservoirs have numerous attributes that make them ideal for safely and securely storing CO_2:

- Established Trap and Seal. The oil reservoirs that are candidates for combined CO_2 sequestration and EOR have accumulated and held fluids for millions of years, providing confidence in the integrity of the reservoir seal and the permanence of the fluid trap.
- Potential for Value-Added Products. In geologically favorable settings, injecting CO_2 into an oil reservoir can permit recovery of a significant portion of the oil left behind after primary and secondary oil recovery.
- Use of Existing Infrastructure. In many cases, essential infrastructure and permits already exist at oil fields for injecting and storing CO_2, leading to lower costs and public acceptance.

Role of CO_2-EOR as a Bridge to Carbon Management

In addition to offering secure locations for storing CO_2, CO_2-EOR could be a valuable near-term bridge toward longer-term CO_2 management.

- CO_2-EOR is already storing industrial CO_2 emissions. Currently, over 2 Bcf/d of CO_2 is injected for CO_2-EOR, one-quarter from industrial sources. **(Figure 5-2)**

State/ Province	Source Type (location)	CO_2 Supply MMcfd	
		Natural	Industrial*
Texas-Utah-New Mexico	Geologic (Colorado-New Mexico) Gas Processing (Texas)	1,300	75
Colorado-Wyoming	Gas Processing (Wyoming)	0	240
Mississippi	Geologic (Mississippi)	400	0
Michigan	Ammonia Plant (Michigan)	0	15
Oklahoma	Fertilizer Plant (Oklahoma)	0	35
Saskatchewan	Coal Gasification (North Dakota)	0	145
TOTAL		1,700	510**

Figure 5-2: Volumes of Natural and Industrial CO_2 Injected for EOR[47] ** Equal to 10 million metric tonnes per year

- CO_2-EOR can help build portions of the essential CO_2 storage and transportation infrastructure for facilitating larger-scale, longer-term storage of CO_2. A number of pipelines already transport industrial CO_2 for EOR, notably the 200-mile CO_2 pipeline from the

Northern Great Plains Gasification Plant in North Dakota to the Weyburn CO_2-EOR project in Saskatchewan, Canada. Other CO_2 pipeline systems link industrial CO_2 with oil fields in Michigan, Oklahoma, West Texas and Wyoming **(Figure 5-3).**

- The experience of the CO_2-EOR industry, and the existing regulatory protocols for health, safety and property rights, also can help establish public confidence on safely and securely storing CO_2 in geological formations. A broader base of experience in integrating CO_2-EOR and CO_2 storage, particularly in portions of the U.S. lacking prior experience with handling, transporting and injecting CO_2 deep into the earth, could facilitate public and regulator acceptance of this important CO_2 management option.

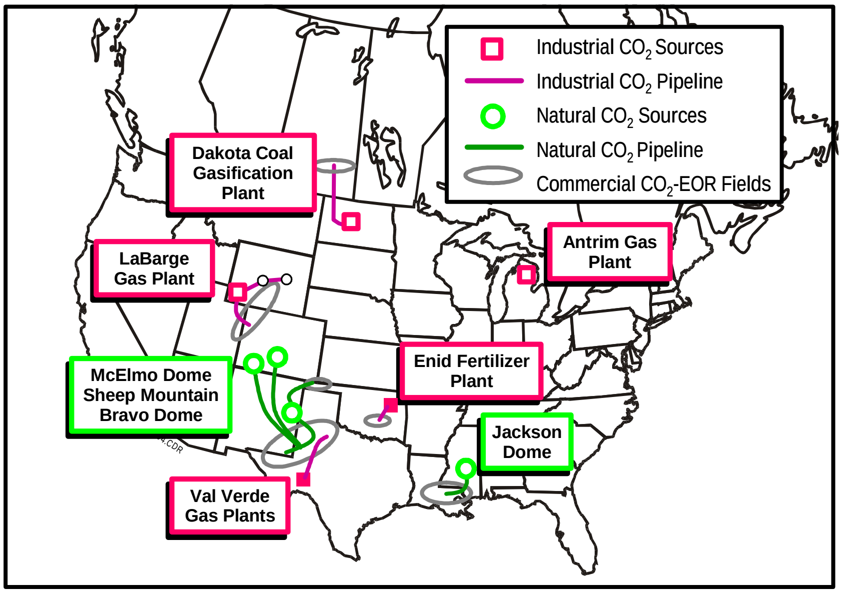

Figure 5-3: Domestic CO_2-EOR Pipeline System and Projects
Source: Advanced Resources Int'l (2006), modified from Oil and Gas Journal and other sources.

CO_2 Storage Capacity Offered by Oil Reservoirs

While large oil fields are an attractive, near-term option for storing CO_2, particularly when storage also may provide significant value-added oil production, considerable uncertainty surrounds the question of how much CO_2 is required and could be geologically sequestered in oil fields as part of CO_2-EOR.

Using the guidelines developed for the 2006 National Geological Carbon Sequestration Capacity Assessment[48], the technical CO_2 storage capacity offered by discovered U.S. oil reservoirs is on the order of 50 billion metric tonnes of CO_2.[49] An additional 20 billion metric tonnes of CO_2 storage capacity exists in the reservoir strata below oil recovery level.

However, under current CO_2-EOR practices, only a portion of this technically available CO_2 storage capacity would become productively used, estimated at 5 to 8 billion metric tonnes[50] under the economic assumptions set forth in the study **(Figures 5-4 and 5-5).**

Basin/Area	Technically Recoverable Oil (Billion Barrels)	Demand for Purchased CO_2 (Tcf)
Alaska	12.4	51.4
California	5.2	23.9
Gulf Coast	6.9	33.3
Mid-Continent	11.8	36.3
Illinois/Michigan	1.5	5.7
Permian	20.8	95.1
Rockies	4.2	27.5
Texas, East/Central	17.3	62
Williston	2.7	10.8
Louisiana Offshore (Shelf)	5.9	31
Total	88.7	377.1

Figure 5-4: U.S. CO2-EOR Technical Market for Purchased CO_2 (Ten basins/Areas)

	Recoverable Oil (Billion Barrels)	Purchased CO_2		Stored CO_2 (Billion Tonnes)
		(Tcf)	(Billion Tonnes)	
Technically Recoverable	89	377	20	10 - 16
Economically Recoverable	47	188	10	5 – 8

Figure 5-5: U.S. CO_2-EOR Technical and Economic Market for Purchased CO_2 (Ten Basins/Areas)

Identifying and Overcoming Barriers to Integrating CO_2-EOR and CO_2 Storage

In spite of its potential, a number of barriers impede wide-scale integration of CO_2-EOR and CO_2 sequestration.

- **Lack of Incentives for Storing CO_2.** The most significant barrier is the lack of revenue or incentives for storing industrial CO_2 beyond the traditional volumes of CO_2 required for EOR. Well-structured incentives will be required if industry is to fully use the secure CO_2 storage capacity offered by oil reservoirs beyond EOR requirements.
- **Limited Current Knowledge of CO_2 Trapping and Storage Mechanisms.** A robust research, development and demonstration (RD&D) program on fundamental CO_2 storage mechanisms – such as capillary trapping, characterization of pore

geometrics, density inversion and mineralization – would greatly improve the knowledge base on how to maximize CO_2 storage capacity and assure its secure, long-term containment.

- **Limitations in Current CO_2-EOR/CO_2 Storage Design and Technology.** CO_2-EOR, as currently practiced, uses only about 10 percent of the storage capacity available in oil reservoirs. A robust set of field demonstrations of applying integrated CO_2-EOR and CO_2 storage in alternative geological and geographic settings is needed to overcome this barrier.

- **Overcoming CO_2 Storage Limitations.** A typical CO_2-EOR project, operated to optimize oil recovery, will inject about 0.25 to 0.30 metric tonnes of purchased CO_2 per barrel of recovered oil. At the end of the project, about 0.15 to 0.20 metric tonnes of CO_2 will remain in the reservoir, depending on trapping mechanisms used.

EOR Utilization

EOR currently uses only 10 percent of available storage capacity in oil reservoirs. Field demonstrations are needed to increase use of available storage in EOR applications.

Integrated application of CO_2-EOR and CO_2 storage, assuming appropriate incentives exist for storing additional CO_2 beyond the requirements of the EOR project, could lead to storing much more CO_2 in the oil reservoir.

In one such application, using a "next generation" CO_2-EOR and CO_2 storage design (involving a gravity-stable CO_2 flood, Figure 5-6), approximately 0.6 metric tonnes of CO_2 is stored per barrel of produced oil, providing an offset for 150 percent of CO_2 emissions.[51]

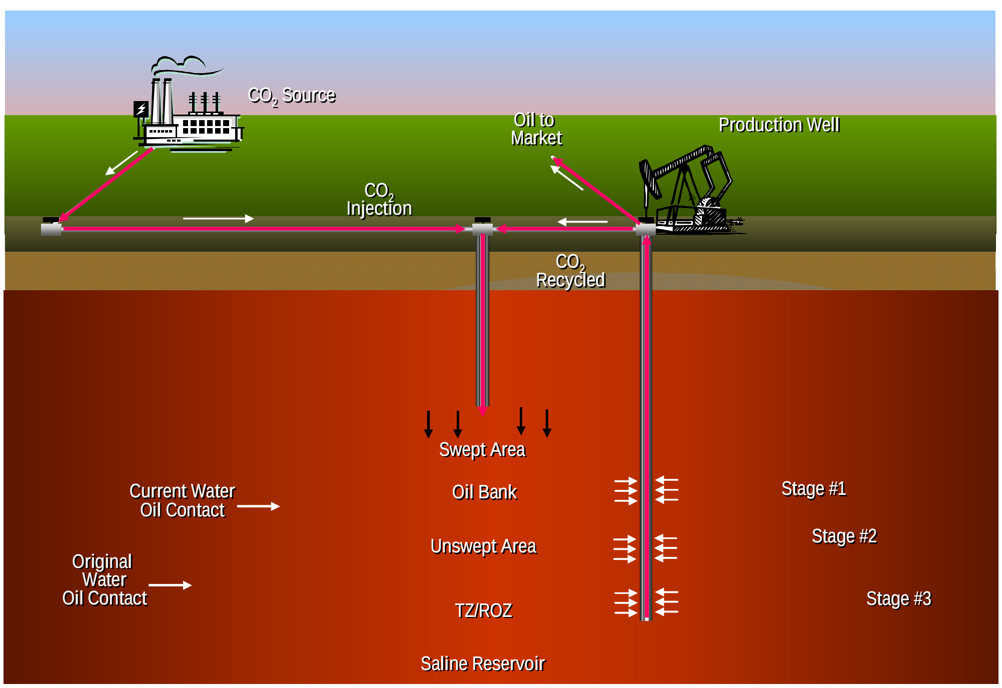

Figure 5-6: Integrating CO_2-EOR and CO_2 Storage with Gravity-Stable Design Source: Kuuskraa and Koperna [52]

In a second example, CO_2 could continue to be injected into the reservoir after the oil production phase has ended. Assuming the announced CO_2 injection design for the Weyburn Project is implemented, this CO_2-EOR project would store about 0.5 metric tonnes of CO_2 per barrel of produced oil, providing an offset for over 80 percent of the CO_2 emissions in the produced oil.

Potential of Enhanced Coal Bed Methane Recovery and Enhanced Gas Recovery for Carbon Storage

Two additional areas of interest for long-term CO_2 storage and increased recovery of hydrocarbon products are:

- **Enhanced Gas Recovery.** Natural gas reservoirs lose pressure as gas is removed. Injection of CO_2 into natural gas reservoirs can help recover additional product by increasing the reservoir pressure.
- **Enhanced Coal Bed Methane Recovery.** Deep unminable coal seams often contain significant quantities of methane adsorbed on the surface of the coal. Injection of CO_2 into these seams displaces the methane because CO_2 is more readily adsorbed on the internal coal surfaces. The methane can be recovered for use, leaving the CO_2 within the deep coal beds for long-term storage.

Estimates of U.S. theoretical storage capacity for storage in depleted gas reservoirs and enhanced coal bed methane applications are 35 and 30 Gt CO_2, respectively.[53]

Experience in sequestration in coal and in enhanced coalbed methane recovery comes from a five-year commercial pilot program run by Burlington Resources in the San Juan Basin of Colorado and New Mexico. Results indicate that CO_2 can be sequestered efficiently in coal and that substantial incremental recovery of coalbed methane is possible at reasonable cost.

Ongoing sequestration tests in coal of the Upper Silesian Coal Basin in Poland are testing the viability of sequestration in deep, unminable coal seams, and the early results are promising.

In the Appalachian Basin of West Virginia, CONSOL is conducting an innovative sequestration and enhanced recovery project that employs a series of vertical and horizontal boreholes (Figure 5-7). This test is in the early stages, so results are not yet available.

Under the U.S. Department of Energy's regional partnership program, a number of small-scale tests are scheduled for coal seams around the nation. Two of these tests are in the Appalachian region, one in Alabama and one in Virginia. The Alabama project is sponsored by the Southeastern Regional Carbon Sequestration Partnership (Figure 5-8). These tests are designed to determine the viability of sequestration in multiple thin coal seams that are distributed through a thick stratigraphic section and thus have a broad range of reservoir properties.

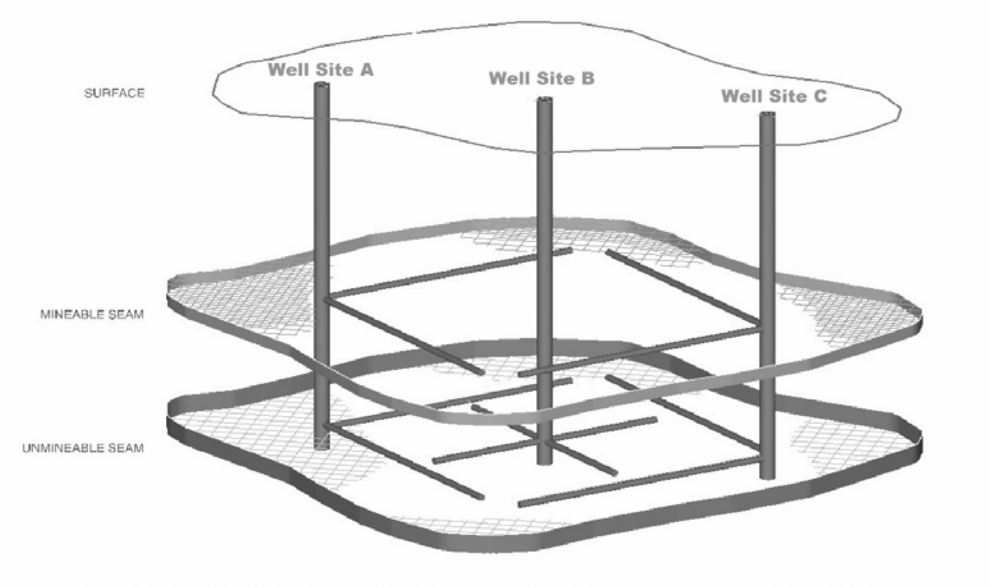

Figure 5-7: Schematic layout of CONSOL's test in the Appalachian Basin Source: CONSOL Energy

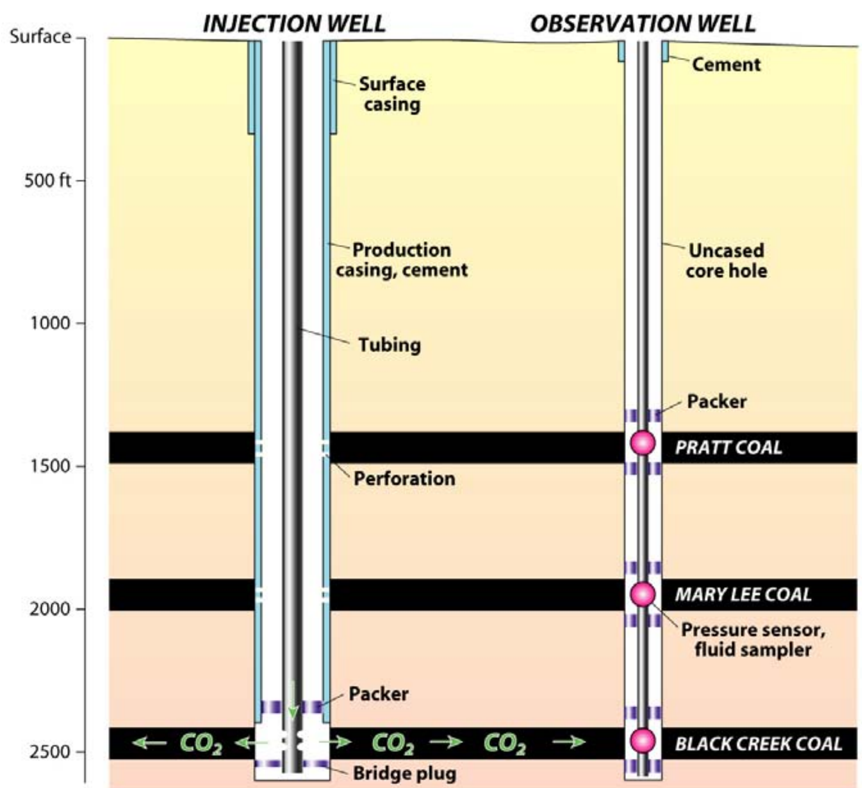

Figure 5-8: Injection and Monitoring Plan for the SECARB Black Warrior Test

(which will involve injection and subsurface monitoring in three separate coal zones)

Source: Southeast Regional Carbon Sequestration Partnership (SECARB)

Other Beneficial Uses of CO_2

Another strategy for carbon capture and storage from coal-fired power plants involves finding new uses for CO_2 that either consume the CO_2 or keep it from the atmosphere. Under current technology, there are three avenues for developing these uses of CO_2: industrial consumption, material production and biological conversion. While any one of these applications would use only a small portion of the total amount of CO_2 generated, they could provide important niche uses of CO_2 in the future.

A variety of industrial uses of CO_2 are currently supplied from other sources. These applications include the manufacturing, consumer products, plastics, chemicals and pesticides. Converting U.S. plastics production to CO_2 feedstocks would consume 100 million tons per year. Other smaller scale industrial applications also could use captured CO_2.

Captured CO_2 also could be converted to a material, specifically carbonates. This strategy is another form of sequestration in which power plant CO_2 is reacted with pulverized sand and other materials to produce magnesium and calcium carbonates. This technology uses significant amounts of energy and requires transporting large amounts of material, which collectively constitute significant economic barriers to adoption.

One of the most interesting potential uses of CO_2 from power plants involves biological conversion. Microalgae systems may offer an interesting biological technology for capture and use of CO_2 emitted from power plants. Large open ponds would cultivate algae with either pure CO_2 or flue gas introduced as small bubbles in the water. The algae can be harvested daily for potential use as biofuels or high-value animal feed supplements. NRG Energy, Inc. and GreenFuel Technologies Corporation (GreenFuel) recently announced they would begin field testing of algae-based technology at an existing coal-fueled power plant in Louisiana.[54] The biomass generated from this process can be used for low carbon liquid biofuel production, such as cellulosic ethanol. Given the state of current technology, land requirements are significant. However, advances in bio-technology to develop more powerful enzymes that accelerate algae growth could reduce these land requirements significantly. And of course, weather conditions in many northern states would not permit algae cultivation all year. Transportation of CO_2 through pipeline networks could alleviate this constraint.

Transportation

The primary mode of CO_2 transport for geologic storage is envisioned to be via pipelines. More than 1554 miles (2500 km) of CO_2 pipeline exists in the U.S. today (Figure 5-9), with a capacity exceeding 40 $MtCO_2$/yr. These pipelines were developed to support EOR operations, primarily in West Texas and Wyoming. In these pipelines, CO_2 is transported as a dense, single phase at ambient temperatures and supercritical pressures. To avoid corrosion and hydrate formation, water levels are typically kept below 50 ppm.

To assure single phase flow, non-condensable gases (e.g., nitrogen, oxygen) are removed and pressures are kept in excess of the critical pressure for CO_2, 1072 psi (73.9 bar). The CO_2 is typically compressed to 2175 psi (150) bar or higher at its source. To maintain supercritical pressures, booster compressors may be needed along the length of the pipeline. However, not all pipelines require recompression. For example, the Weyburn pipeline, which transports CO_2 about 205 miles (330 km) from an industrial facility in North Dakota to an EOR site in Saskatchewan, Canada, operates without a recompression system.

Pipeline	Operator	Capacity ($MtCO_2$/yr)	Length Miles (km)	Year finished	Origin of CO_2
Cortez	Kinder Morgan	19.3	502 (808)	1984	McElmo Dome
Sheep Mountain	BP Amoco	9.5	410 (660)		Sheep Mountain
Bravo	BP Amoco	7.3	217 (350)	1984	Bravo Dome
Canyon Reef Carriers	Kinder Morgan	5.2	140 (225)	1972	Gasification plants
Val Verde	Petrosource	2.5	81 (130)	1998	Val Verde Gas plants
Weyburn	North Dakota Gasification	5	204 (328)	2000	Gasification plant

Figure 5-9: Major CO_2 Pipelines in US [55]
Source data: IPCC

Figure 5-10: The 10-inch Diameter Val Verde Pipeline Transports CO_2 from Four Gas Treating Plants to the Canyon Reef Carriers Pipeline, Used for EOR Operations[56]

In today's commercial markets, CO_2 is routinely transported by rail and road tankers. Typical conditions in a tanker are liquid CO_2 at 290 psi (20 bar) and -4° F (-20°C). However, for the large quantities of CO_2 that will need to be transported for sequestration, tanker transport is likely uneconomic for any significant distance or plant size.

It has also been suggested that CO_2 can be transported by ship. Ships generally will be more expensive than pipelines for transporting CO_2 moderate distances (hundreds of kilometers). However, for longer distances, ship transport may be competitive. Liquefied natural gas (LNG) tankers are not a good mode for CO_2 transport because LNG is transported at atmospheric pressure. Since CO_2 is not a liquid at atmospheric pressures, it must be transported at elevated pressure (in excess of its triple point pressure of 75 psi (5.18 bar). A better comparison for CO_2 transport by ship is liquefied petroleum gases (LPG), which currently are shipped on a small scale.

Safety and Environment

Title 49 of the Code of Federal Regulations, Parts 190-199, embodies the regulatory framework for ensuring the safety and environmental compliance of pipeline transportation. This regulatory framework is well developed and reflects much of what is known about transporting materials via pipeline. Under federal regulations, CO_2 pipelines are classified as "High Volatile/Low Hazard" and "Low Risk."[57]

More than 322,000 miles (536,000 km) of natural gas transmission pipelines and 155,000 miles (249,000 km) of hazardous liquid pipelines exist in the U.S.[58] Transportation of CO_2 is much safer than these fluids because CO_2 is non-toxic and non-flammable. However, CO_2 is an asphyxiate starting at concentrations in the range of 7-10 percent by volume. Most leaks from a CO_2 pipeline would be dispersed before ambient concentrations reached such high levels. However, CO_2 pipelines potentially could become a safety threat in unique circumstances, requiring a combination of a significant CO_2 leak, favorable topography (e.g., a low-lying bowl in which CO_2, which is heavier than air, could accumulate), and calm winds. Therefore, CO_2 pipeline best practices include, but are not limited to, selecting sites and methods for pipeline construction that reduce the probability of accumulation in the event of a leak. It should be noted that, to date, there have been no injuries associated with leakage from the existing CO_2 pipeline network.[59]

Infrastructure and Costs

Transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10 Mt CO_2/yr. While Figure 5-11shows typical values, costs can be highly variable from project to project because of physical (e.g., terrain the pipeline must traverse) and political considerations. For a 1,000 MW_e coal-fired power plant, a pipeline would need to carry about 8-10 million tons /yr (7-9 million metric tonnes/yr) of CO_2 per year. This would result in a pipe diameter of about 16 inches and a transport cost of about $1 per ton of CO_2 per 62 miles (100 km). Transport costs can be lowered through development of shared pipeline networks as opposed to dedicated pipes between a source and repository.

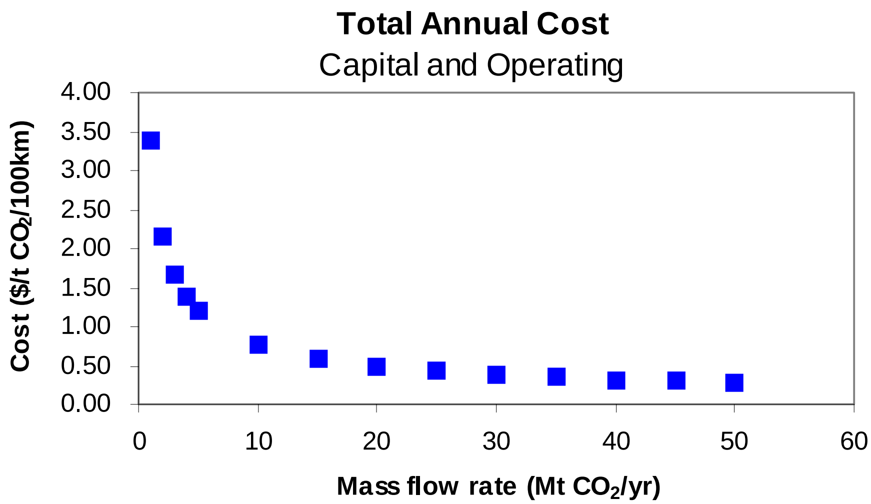

Figure 5-11: Illustrative Costs for CO_2 Transport via Pipeline as a Function of CO_2 Mass Flow Rate[60]
Source: MIT

Figure 5-12 shows a map of U.S. coal plants overlaid with potential sequestration reservoirs. The first CCS projects are expected to involve plants that are very close to a sequestration site or an existing CO_2 pipeline. As the number of projects grows, regional pipeline networks will evolve, similar to the growth of existing regional CO_2 pipeline networks in West Texas and in Wyoming to deliver CO_2 to the oil fields for EOR. For example, Figure 5-12 suggests that a regional pipeline network may develop around the Ohio River valley.

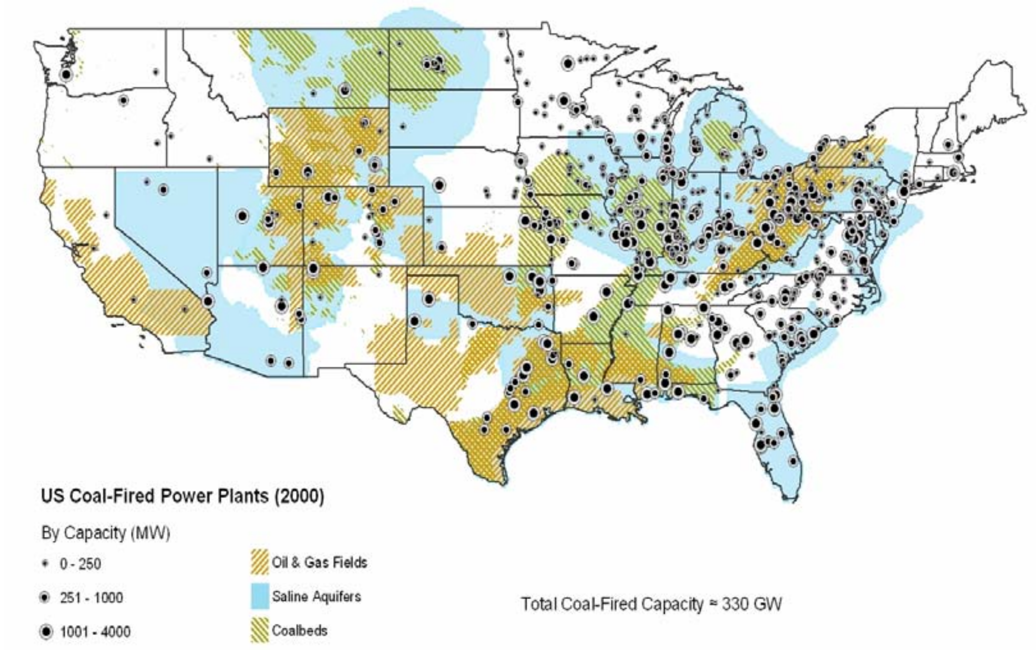

Figure 5-12: Map Comparing Location of Existing Coal-fired Power Plants in the U.S. with Potential Sequestration Sites[61]
Source: MIT

However, detailed knowledge of capacity for sequestration sites is still very limited. The map above is preliminary and needs further development and analysis to provide a complete identification of potential sequestration sites. Some shaded areas above may prove unfavorable with further study, while detailed surveys may show sequestration potential in places currently not identified.

Natural (Terrestrial) Carbon Sequestration Stimulation

Introduction

Besides the mechanical means of capturing and storing CO_2 discussed in this section, natural means of addressing CO_2 capture and storage offer many immediate, low-cost possibilities with significant environmental benefits. They should also be the subject of further research and development.

Terrestrial carbon sequestration is defined as either the net removal of CO_2 from the atmosphere or the prevention of CO_2 net emissions from terrestrial ecosystems into the atmosphere.[62] Terrestrial carbon

Terminology

Terrestrial carbon sequestration *refers to process of increasing the carbon stored in a pool or reservoir (terrestrial, ocean, biotic) other than the atmosphere.*
Carbon flux *refers to the transfer of carbon from one carbon pool or another.*
Carbon stock *refers to the absolute quantity of carbon held within a pool at a specified time.*
Soil organic carbon *(SOC) can be generally defined as all organic matter in a soil excluding non-decayed plant tissues (e.g., roots) and living organisms. SOC sources includes CO_2 fixed by plants, leaf litter and root exudates.*

sequestration involves storing carbon in plants and soil. Carbon sequestration results when the accumulation of CO_2 through photosynthesis exceeds the loss of carbon through plant respiration, decomposition, erosion, fire, land use and other disturbances.

Vegetation and soil have a great capacity to capture and store large amounts of carbon and thus are considered "carbon sinks." The soil carbon pool, which comprises organic and inorganic carbon, is the largest pool of terrestrial carbon, approximately 2,200 billion metric tonnes. It contains about four times the carbon stored in plants and three times that in the atmospheric pool.[63] In the 1990s, a large carbon sink could not be accounted for. This residual or "missing" carbon sink, approximately 2.3 billion metric tonnes carbon per year,[64] is commonly attributed to unknown terrestrial sinks, such as carbon sequestration in soils and plant regrowth.[65]

Since most CO_2 enters the ecosystem via photosynthesis, carbon accumulation is most obvious when it occurs in above-ground biomass. Eventually, more than half the assimilated carbon is transported below-ground via root growth and turnover, root exudates (organic substances) and litter deposition. The transfer of atmospheric CO_2 to soil organic carbon (SOC) is critical to long-term removal, which requires the transfer of fixed carbon into long-lived ecosystem pools, such as terrestrial and geologic pools.

There are several general approaches to terrestrial carbon sequestration:

1) protection of ecosystems so carbon stores can be maintained or increased;
2) restoration of ecosystems with land-use conversion where ecologically sound; and
3) management of ecosystems to increase SOC sequestration beyond current conditions.

Converting or restoring land to a more natural state can replace the SOC losses that occurred when land is converted to managed systems, such as farming. However, restoration and management practices need to focus both on increasing the rate of carbon uptake and the long-term storage of carbon in managed ecosystems.

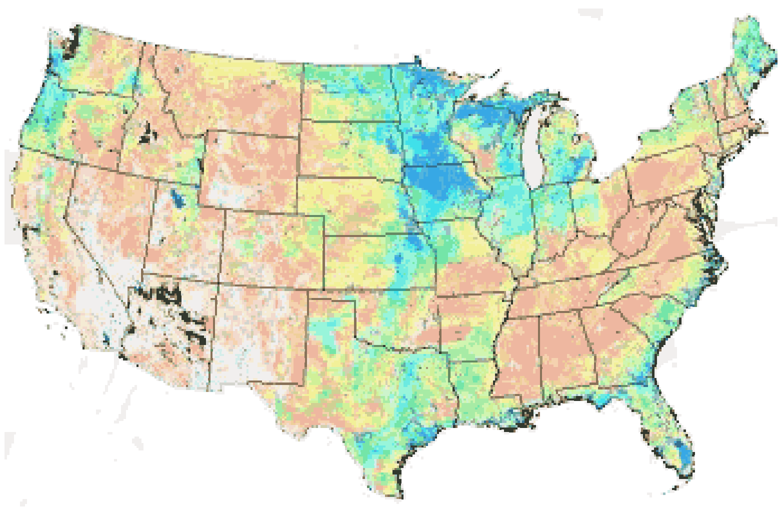

Figure 5.13 Soil Organic Carbon in the U.S.
Source: U.S. Geologic Survey
(Blue indicates areas with high natural concentrations of SOC)

Management Practices

Terrestrial carbon sequestration is recognized for its technical, economic and environmental benefits. The IPCC Third Assessment Report (2001)[66] estimates about 100 billion metric tons over the next 50 years could be sequestered globally through forest preservation, tree planting and improved agricultural management, offsetting 10-20 percent of the world's projected fossil fuel emissions.

For carbon sequestration to succeed, practices have to increase the rate of carbon accumulation, enhance the transfer of carbon to longer-lived pools, increase the duration of selected carbon pools and increase retention to achieve lower net greenhouse gas releases. Practices that maintain and sequester carbon can have both positive and negative effects on other greenhouse gas emissions (e.g., methane and nitrous oxide).

Soil carbon sequestration implies the storage of fixed carbon. Therefore, carbon sequestration strategies need to focus on increasing SOC density in the soil, improving depth distribution of soil organic carbon, and stabilizing SOC within the soil structure so that it is protected from microbial processes and remains in the soil for a very long time.[67]

The current and potential rates of carbon sequestration and assessments of carbon storage permanence need to be better understood for various terrestrial ecosystems and soil/vegetation/wetland management options. Carbon fluxes and stocks are key measurements needed to quantify carbon budget sinks and sources and the mechanisms controlling them.

Land use, vegetation and soil management practices, which involve intentional soil and vegetation manipulation, can have a strong impact on the biotic processes of carbon sequestration.[68] The practices that increase net primary production and/or retain more plant materials to the soil have the most potential to increase soil carbon stock. To varying degrees of success, soil carbon sequestration can be accomplished by agricultural and forestry management practices and wetland restoration.

Agriculture

When degraded soils are restored, their capacity to store carbon is greatly increased. The capacity of agricultural soils can be enhanced by adopting management practices that increase soil organic carbon and minimize its losses, converting marginal agricultural soils to a restorative land use and replanting with perennial vegetation.

Agronomic management practices (i.e., reduced or no-tillage, integrated nutrient management, mulch farming) can increase SOC as tilling of soil is eliminated, erosion is minimized, and large quantities of root and above-ground biomass are returned to the soil. In addition to SOC accumulation, agronomic practices can conserve water and improve soil quality.

Improved agricultural methods can lead to quantifiable terrestrial sequestration credits that could be traded in a carbon market resulting in a new source of income for farmers and providing incentives to adopt a wide range of restoration and sustainable land management practices. However, croplands have the smallest carbon stocks because the vegetation is periodically plowed up, rather than being allowed to accumulate.

Forestry

Carbon dioxide levels can be mitigated through forestry, afforestation (planting trees on open land for commercial purposes), and agroforestry (combines agriculture and forestry for the creation of sustainable land use) practices. These managed forests theoretically sequester carbon both in-situ (biomass and soil) and ex-situ (products). Carbon sequestration can occur through afforestation, reforestration, restoration of degraded lands, improved forestry management to increase growth rates, and implementing agroforestry practices on agricultural lands. Conservation of biomass and soil carbon in existing forests or by improved harvesting practices has the greatest potential for rapid mitigation of climate change, while carbon sequestration takes much longer.[69]

However, similar to agriculture land management strategies, forestry practices have a finite effect corresponding to the finite capacity of the soils to store carbon. For example, forests will not sequester additional carbon after the trees have fully grown. Mature trees or forestry practices will still need to be sustained to maintain the level of accumulated carbon.

Wetlands

While wetlands release CO_2 and trace emissions of methane and nitrous oxide, wetlands sequester much more atmospheric carbon. Wetlands are net carbon sinks if the rate of plant production exceeds the rate of decomposition for biomass, litter, wetland soils and exceeds the net export through release of gases or water transport of dissolved carbon or sediments.

CO_2 may be temporarily stored in wetland vegetation (biological sequestration); however, significant quantities of carbon are trapped and stored long term in the organic-rich soils, peat and other sediments in wetlands, making wetlands effective carbon reservoirs. Extensive peat deposits throughout the world underlying many current and former wetlands demonstrate the long-term effectiveness of wetlands in storing carbon.

> **Demonstrations**
>
> *Demonstration projects, particularly for wetlands, are needed that focus on increasing both the rate of carbon uptake and the long-term storage of carbon and on the collateral ecological benefits.*

Wetlands can store more carbon than other ecosystems despite their low productivity because of high rates of organic matter inputs and low decomposition rates. As a carbon sink, river wetlands can accrue much more carbon than managed agricultural systems. These wetlands can uptake 0.61-0.81 tons C/acre/year (net sequestration) compared to only about 0.08 tons C/acre/year for agricultural lands.[70]

Wetlands have the highest carbon density among terrestrial ecosystems and relatively greater capacities to sequester additional carbon. A major portion of detrital matter is buried via accretion in wetlands, which serves as long-term carbon storage. Organic matter accretion rates have ranged from millimeters to 1 cm/year for constructed and natural wetlands;[71] however, the rates and duration of accumulation of organic matter depend on biogeochemical processes in wetlands. Unlike agriculture or forestry ecosystems, managed wetlands can continually accrue organic carbon.

Potential Liability for Stored Carbon Dioxide

The Need for Proper Risk Management and Allocation

Risks

Short-term risks must be managed by adequate engineering of capture, transport and injection systems with strict attention to safety issues.

Entities that undertake CCS activities, whether as volunteers participating in a demonstration project such as FutureGen or regulated parties responding to legal mandates, will face several categories of tort and regulatory liability exposure. Exposure to uncertain liabilities for decades into the future can impede technological innovation and implementation. This discussion will review the categories of CCS liability risk and conclude that the risks of liability presented by long-term storage of CO_2 in geological formations, in large part, should be reduced or reallocated to public sector entities as a matter of public policy.[72]

The capture and sequestration of CO_2 emissions from fossil fuel combustion involves several categories of risk, some short-term and relatively manageable and others long-term and less manageable.

Short-term risks include those associated with removing CO_2 from exhaust gases and transferring the CO_2 from the location of capture to the site of injection into the storage reservoir. One such risk is the potential regulatory liability for failure to adequately capture the CO_2 so as to comply with mandatory CO_2 emission caps imposed by a future regulatory program. If the emission caps are achievable through installation of available control technology that is both technically feasible and economically reasonable, regulatory sanctions resulting from noncompliance with emission control obligations are properly incurred by the emitter and should not be reallocated to other entities.[73]

Another risk is tort liability exposure to claims for personal injury or property damage resulting from faulty design, installation or maintenance of transmission pipelines or from the rupture of or leakage from pipelines. Similar risks presently are incurred by natural gas and oil industry pipeline operators, and are managed by exercising the proper level of care and through private insurance. Risks associated with transmission of gases through high-pressure pipelines are not limited or reallocated to other entities under current law. These types of short-term risks generally are not proper candidates for liability limitation or reallocation.

Uncertainty

Uncertainty about long term liability will prevent many private sector entities from volunteering for a demonstration project or engaging in CO_2 sequestration unless a mechanism is in place to substantially reduce the risk or reallocate it to other entities.

High-pressure injection of gas into geological formations for long-term storage, however, is not currently conducted by analogous commercial enterprises, and presents uncertain long-term risks that ought not to be borne entirely by entities conducting the injection and storage.[74] Such risks include potential tort liability for:

- damage to groundwater resources, either through contamination or loss of the water through fissures created in previously impermeable geological strata,
- changes in surface topography, resulting in damage to structures or alteration of drainage patterns,
- personal injury caused by leakage of enough CO_2 into the atmosphere to displace breathable air, and leakage that may contribute to atmospheric warming.

Regulatory liability may also be incurred by these events if leakage or adverse surface impacts upon persons or property violate regulatory requirements.

Exposure Impedes Technology Development

These events may not occur until many years after injection of the CO_2, and may not be foreseeable based upon the state of geological science at the time of injection. Uncertainty about the likelihood and severity of these long term adverse events, and about the state of tort and regulatory law at the time of occurrence, will prevent many private sector entities from volunteering for a demonstration project or engaging in CO_2 sequestration unless a mechanism is in place to substantially reduce the risk or reallocate it to other entities. Confining the burden of post-injection in situ liability risks to the injecting entity would impede carbon sequestration technology innovation and implementation.

In addition, confining such risks to the injecting entity would be inconsistent with the impetus for CCS technology. Government, acting to protect the public and the environment from the perceived risk of atmospheric warming through regulatory mandates to capture and store CO_2 in geological formations, ought not to require the regulated entities to bear the entire risk of long-term liabilities. Legislation mandating CCS behavior modification should take account of the benefits derived from CCS activities and give the entities performing those activities a large measure of long-term risk reduction and/or reallocation.

Long Term Risk

Risks associated with improper siting of long-term storage operations should be resolved through a proper front-end siting approval processes. Once the siting criteria have been met, there should not be liability for actions consistent with the requirements governing the siting approval.

Managing Risks

Risk reduction and reallocation can take several forms, all requiring federal legislation. One approach is to provide immunity to CCS actors from long-term risks, either through an extinction of liability or by placing a monetary limit on liability. Immunity standing alone, however, transfers the risk to the persons incurring harm, and so is most appropriate for risks that do not directly involve personal injury or property damage.

Examples of risks where immunity may be appropriate are regulatory liability for leakage of CO_2 from the storage reservoir into the atmosphere, including both enforcement sanctions and loss of regulatory credits or allowances that the CCS actor may have acquired by virtue of capturing and storing the CO_2. Other candidates for immunity are claims on behalf of the public that leakage contributed to the public nuisance of atmospheric warming and claims for personal injury or property damage resulting from conditions, such as severe weather, caused by atmospheric warming. These theories of tort liability for CO_2 emissions are presently being tested in pending actions,[75] and ultimately may be found by appellate courts to lack merit. If contributing to atmospheric warming is found to be a viable theory of tort liability, however, liability based on reservoir leakage is a good candidate for immunity legislation. If Congress decides there is merit in a national legislative program to limit and manage greenhouse gas emissions, such legislation should pre-empt and displace case-by-case tort law litigation over climate change science and policy, whereby some 668 federal trial judges or over 10,000 state court trial judges might strike a different balance than the course charted by Congress.

A second approach is transfer of liability to a public entity. This reduces or eliminates the risk otherwise borne by the CCS actor, and also assures the existence of a financially viable entity to pay claims at the time the claims arise (which could be in the far distant future). A recent example in the area of CO_2 storage is Texas House Bill 149 (Tex. Nat. Res. Code Ann. Ch. 119; effective September 1, 2006). That legislation, passed as part of the state's effort to attract the FutureGen project, provides that the Railroad Commission of Texas "shall acquire title to carbon dioxide captured by a clean coal project." By implication, the Commission also acquires any liability associated with the CO_2 (Tex. Nat. Res. Code Ann. Section 119.002(a)). Risks associated with improper siting of long-term storage operations should be resolved through a proper front-end siting approval processes. Once the siting criteria have been met, there should not be liability for actions consistent with the requirements governing the siting approval.

A third approach is indemnity by a public entity, such that the risks of socially desirable activities are spread among the large number of beneficiaries of such activities. A prime example is the Price-Anderson Act, as amended, 42 USC Section 2210, which provides for indemnification by the government, up to stated limits, of claims arising from nuclear accidents. The public policy underlying the legislation is to encourage development and operation of nuclear facilities as part of the nation's energy supply, which would not otherwise occur because of the lack of available, affordable insurance to cover the risk of nuclear accident. Indemnity for long-term CO_2 liability risks, as in Price-Anderson, may cover claims only over a stated amount of retained liability of the CCS actor, reflecting the extent of liability that can be affordably addressed through private insurance.

The mechanism ultimately provided by law to limit and/or reallocate long-term liability may be a combination of these approaches. But such a mechanism, in some form, is necessary to equitably allocate to government the long-term risk associated with CO_2 injection and storage the federal government either encourages or requires to address climate change concerns.

CONCLUSIONS

Progress in geological storage of CO_2 can be accelerated through a focused program of research and development in the following areas:

- Multiple, large-scale demonstration sites for CO_2 storage in formations such as saline reservoirs are needed in the U.S. to provide sinks for initial carbon capture projects, test monitoring methods and equipment, and identify legal, regulatory and practical concerns. Further research is needed to gain greater insight and confidence in long-term storage mechanisms, such as solubility, capillary and mineral trapping, that increase storage security in the post-injection period; and methods must be identified for remediating storage projects that are not performing well in terms of injectivity, capacity and containment.

  Key research areas include:
  - Efficient methods for site characterization and selection – focusing on assessing injectivity, capacity and containment. This includes characterizing the seal, or caprock, of a storage formation over the large spatial scales needed for commercial-scale storage projects.
  - Reliable methods for estimating the capacity and plume footprint (location of injected CO_2 projected on the land surface) for CO_2 stored in saline formations.
  - Effective techniques for monitoring CO_2 plume migration and containment in the storage reservoir – and techniques to assess the rates and source of leakage should it occur.
  - Reliable methods for assessing and mitigating the potential for abandoned wells to compromise storage integrity.
- Development of a strong base of CO_2 pipeline design standards, with consistent national approval and permitting processes to provide public confidence.
- Siting of power plants is a complex and lengthy process, integrating transmission access, ease of fuel transport, water and land use, by-product transport, etc. Successful implementation of carbon capture will add a significant additional level of complexity in siting due to the need to access acceptable storage or for pipeline to storage. It is critical that the addition of planning for CO_2 capture and sequestration does not add excessive time to the development of new generation capacity. Development of CO_2 pipelines and certification of storage sites needs to be a national priority, and should not be the sole responsibility of individual generation plant owners.
- CO_2-enhanced oil recovery, with its industry experience, and existing regulatory protocols, provide an important commercial path for CO_2 storage, and a bridge to utilizing formation, such as saline reservoirs, that hold the largest potential for CO_2 storage.
- Carbon capture and geologic sequestration will create potential long-term liabilities. Implementation of CCS would be in response to anticipated or existing government imposed limits on CO_2 emissions; therefore, these liabilities should not be imposed on the electric generators or coal producers. As such activities are done to serve the public good as determined by the government, the entities performing those activities should be provided a large measure of long-term risk reduction.

- Deployment of agricultural management, forestry practices and wetland restoration for terrestrial carbon sequestration to reduce the rate of accumulation of CO_2 in the atmosphere while restoring degraded soils, enhancing biomass production and generating environmental co-benefits (e.g., improved water quality, biodiversity protection, land conservation, erosion reduction, etc.).
- The nation should pursue all avenues of reducing CO_2, including further research into finding beneficial uses of carbon dioxide such as to spur algae growth and create biofuels.

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SECTION SIX

Technology Profiles and Trends

FINDINGS

- Reduction, capture and sequestration of carbon dioxide (CO_2) emissions from industrial processes has been accomplished through use of technologies that are now proven in regular use or commercial-scale demonstration projects with conditions reasonably close to those expected for coal-based processes. However, these technologies would not necessarily be cost-effective at the scale required by coal-fired power plants.
- Although the current state of coal-based technology is promising, major near-term technological advances (and associated investments) are still required if greenhouse gas emissions reductions are to be made within society's desired timeframe and financial constraints.
- A Carnegie Mellon University study indicates that early commercial viability will result only with early commitment to necessary research, development and demonstration (RD&D) programs by organizations and/or collaborations that accept the cost and schedule risks and proceed to "learning by doing" with commercial-scale demonstration projects.
- Analysis of the current state of carbon capture and storage (CCS) technology, with reference to these patterns, provides optimism that necessary advances can be made to meet goals for CO_2 capture and sequestration, but also emphasizes that success will require a stronger and more concerted and collaborative effort than is currently under way.
- Technology-neutral consensus goals, contained in the 2006 update of the Coal Utilization Research Council-Electric Power Research Institute (CURC-EPRI) Roadmap for coal-based power generation without CO_2 capture, aim at a 10-30 percent reduction in capital cost combined with a 10-20 percent improvement in net efficiency.
- A broad portfolio of technologies is needed to equip society to reach greenhouse gas reduction goals. For coal-based power generation, no single technology is clearly superior. Gasification-based and combustion-based technologies are competitive, each having cost and other advantages for different fuels and operating environments.
- RD&D plans for integrated gasification combined cycle (IGCC) with CO_2 capture provide a pathway toward realization of a roughly 30 percent reduction in the capital cost, over the next 20 years on a constant dollar basis, while increasing net efficiency by 9 percentage points.
  - For IGCC, key technology advances are needed mostly in the areas of reliability, availability and capital cost of the base technologies.
  - Proven technology for CO_2 capture from high pressure gasification systems is well established in chemical plants.
- Current RD&D plans for advanced pulverized coal (PC) generation with CO_2 capture provide a pathway toward realizing a 30 percent reduction in the capital cost, over the next 20 years on a constant dollar basis, while increasing net efficiency by 12 percentage points.

- For PC generation, key technology advances are needed mostly in the area of CO_2 capture processes, as current processes have high capital costs and high auxiliary power or steam demand.
- Japan and Europe already have some operating experience with ultra-supercritical PC technology.

Technology Development Setting and Life-Cycle

As discussed in earlier chapters, desired reductions in CO_2 emissions are likely to require both a decrease in CO_2 production and the implementation of CCS. New facilities that incorporate advanced technologies for coal power generation will produce up to 30 percent fewer CO_2 emissions, on a per megawatt-hour (MWh) basis, than do most existing coal-based facilities. CCS promises much greater reductions – up to 90 percent or more of a generating unit's net emissions. Although in theory CCS could be implemented with current technology on existing units, an order-of-magnitude scale-up would be required and the capital and operating costs could be unacceptably high. Also, this application would be limited by the proximity of facilities to appropriate CO_2 sinks. Incremental costs for CCS implementation will be much lower for advanced coal technology facilities than for the existing fleet, both for retrofit after commissioning and for CCS integrated with the original design. Developing technologies for CO_2 capture also promise much better benefit/cost ratios.

Technologies of interest are currently at many different stages of development:

- Core power generation technologies are largely at the demonstration stage. Significant improvements for specific areas are at developmental, pilot or demonstration stages.
- While workable technologies for post-combustion CO_2 capture have been used commercially in other applications, it is believed that the efficiency and economics will be greatly improved with Oxy fuel combustion and solvent absorption technologies which are at the developmental and pilot-scale demonstration stages.
- For IGCC, improved capture efficiency depends on successful implementation of hydrogen-fired combustion turbines, which is near demonstration stage for some combustion turbine (CT) models and in early development for others.
- While a significant experience base has been developed for CO_2 injection for enhanced oil recovery, CO_2 injection for long-term geologic sequestration is generally at pilot scale. A few larger CCS demonstrations have been conducted internationally. Several projects are in planning stages in North America.

At the early stages in any technology's "life-cycle," costs are higher than those for mature commercial technologies that have benefited from economies of scale in design and production and from decades of "learning by doing." Thus, advanced coal power and coal-to-fuel technologies face the hurdle of higher costs that can impede market introduction and adoption.

With the high costs and long lead times inherent in bringing new power generation and CCS technologies to market, a sustained and well-coordinated RD&D effort will be required if the desired technology advances are to be achieved within society's timeframe for making substantial progress in reducing industrial greenhouse gas emissions. It is uncertain whether all the desired technologies will advance beyond the stage of initial price premiums without a collaborative mechanism to distribute the risks and benefits among a variety of stakeholders.

Advanced Coal Technologies versus the RD&D Learning Curve

> **Commercial Readiness**
>
> *Many key enabling technologies still require significant refinement, thorough testing and successful demonstration before they can achieve commercial (and public) acceptance.*

Engineering and economic studies by the U.S. Department of Energy, EPRI, major universities, original equipment manufacturers and engineering firms suggest that advanced, coal-based power and fuel production technologies will be economically viable under policies requiring greenhouse gas emission reductions – if they can get past the initial cost premium and onto the "learning-by-doing" cost reduction curve associated with widespread deployment. Even with substantial costs for CO_2 capture and sequestration, coal-based power generation technologies will remain competitive with alternatives because of coal's inherent advantage as a low-cost, domestically produced, easily stored fuel.

History demonstrates that new technologies for power generation and emissions control earn broad commercial acceptance only after incorporation of lessons learned by early adopters who shoulder significant cost, schedule and performance risks. The power industry recognizes that current market conditions may inhibit potential early adopters and has developed collaborative RD&D mechanisms to help surmount this obstacle. These collaborations facilitate the sharing of costs, commercial risks and new technical knowledge among suppliers, early adopters, government agencies and others who have a stakeholder interest in subsequent deployment and who can benefit from an insider's view of initial experience and lessons learned.

Timing is crucial. Demand growth and shrinking reserve margins are compelling electricity producers to commit to baseload capacity additions within the next few years. Similarly, transportation fuel providers are making capacity expansion decisions. Concurrently, momentum appears to be building for climate change legislation that would limit CO_2 emissions from power plants, refineries and other industrial sources. A narrow window of opportunity exists in which a robust portfolio of environmentally acceptable, advanced coal-based power and fuel technologies can be established *before* major capital commitments must be made. Industry must quickly ramp-up deployment of current advanced coal technologies if there is to be sufficient time to develop experience-informed measures to reduce cost and risk. Ultimate commercial acceptance (and major cost reduction) depends on advanced coal technologies being proven in full-scale operation, under real-world conditions, for enough time to meet expectations of cost, performance and reliability, and to pinpoint high-payback opportunities for improvement.

Figure 6-1 illustrates the model of cost expectations for full-scale application as a function of the state of development and commercial maturation on a "deployment curve" (sometimes called the "mountain of death"). An EPRI assessment of the approximate location on the curve of coal-based power generation and CCS technologies is shown.

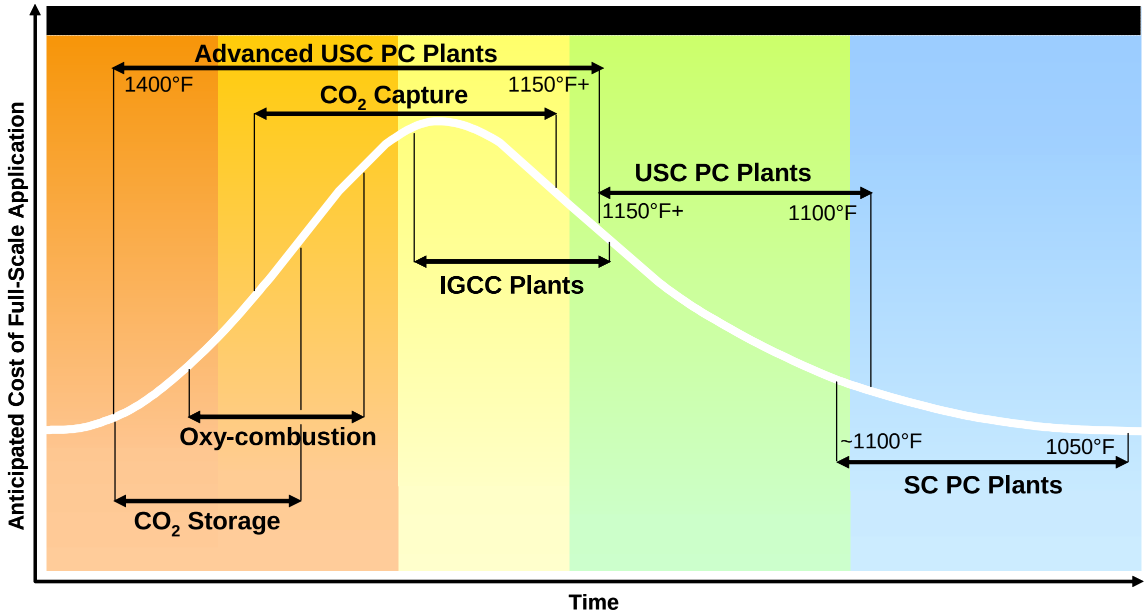

Figure 6-1: New Technology Deployment Curve for Coal [76]
Source: EPRI

For any technology to advance from initial conception to commercial production, sponsors and investors must be willing to bear significant cost and technology risks to shepherd its development from bench scale to full scale. The process of technology development and scale-up reduces uncertainty and, almost invariably, quells the bullish optimism that was initially needed to launch the RD&D effort. As illustrated by the rising anticipated-cost curve on the left side of Figure 6-1, most development programs will experience a growing recognition that the cost of a full-scale application will be greater than the amount forecast by early conceptual estimates. Often, the cost of the demonstration project will exceed the final pre-construction estimates before the plant is fully operational.

The apex of the anticipated-cost curve is typically reached while the bugs are being worked out of a technology during a successful full-scale demonstration program. Subsequent implementations benefit from the accumulation of lessons learned until the curve flattens (i.e., the rate of cost reduction slows) as the technology matures.

As shown in Figure 6-1, IGCC *without CO_2 captur*e may not yet be over the hump. CO_2 capture, Oxy fuel combustion (capture) and CO_2 storage technologies are still at the stage where cost uncertainty is large, a fact not always made clear in published studies which may contain optimistic forecasts. Regardless of the relative positioning on the deployment curve, it is evident there is an urgent need for a well-coordinated, fully-funded RD&D program to help remove barriers to advanced coal technology selection and deployment, and thereby move society's stakeholders as quickly as possible to the lower cost and risk of building "nth-of-a-kind" plants rather than first-of-a-kind plants.

Insights from a Historical Review of the Learning Curve for New Coal Power and Emission Control Technologies

Research sponsored by the International Energy Agency (IEA) Greenhouse Gas R&D Programme and performed by Carnegie Mellon University (CMU) uses historical cost trajectories for component technologies to predict possible future trends in the costs of power plants with CO_2 capture. As current cost data are not sufficient for estimating the costs of future CO_2 capture technology, the study[77] applied a predictive computer model, CMU's "Integrated Environmental Control Model," which projects the future costs of major power plant subsystems by applying historical learning rates to estimates of current costs. For inputs to this model, the CMU team analyzed historical trends and established average learning rates for seven technologies comparable in scale to ones used for power plants with CO_2 capture:

- Flue gas desulfurization (FGD)
- Selective catalytic reduction (SCR)
- Pulverized coal boilers
- Combined cycle power plants
- Liquefied natural gas (LNG) production plants
- Oxygen production plants
- Steam methane reforming (SMR) plants for hydrogen production

The average learning rates were derived from capital costs and operating and maintenance (O&M) costs for each representative technology. They reflect differences in technological maturity for different types of plants and different subsystems within those plant types. The model provides outputs for a desired maturity level (e.g., 100,000 megawatts [MW] installed).

The "mountain of death" phenomenon depicted in Figure 6-1 also can be seen in the charts in Figure 6-2, which represent capital and O&M cost trends experienced during the introduction and maturation of wet flue gas desulfurization technologies. The source of these charts, a paper[78] presented at the 8th International Conference on Greenhouse Gas Control Technologies by the CMU team, explains this phenomenon, in part, as follows:

> *"Since there is no easy or reliable method to quantify potential cost increases during early commercialization (a common phenomenon also seen in several of the case studies), we instead assume that any such costs effectively delay the onset of learning until later generations of the plant or process are designed, deployed, and operated for a period of time. With additional experience, the higher plant costs incurred initially are gradually reduced (via learning-by-doing and continued R&D)."*

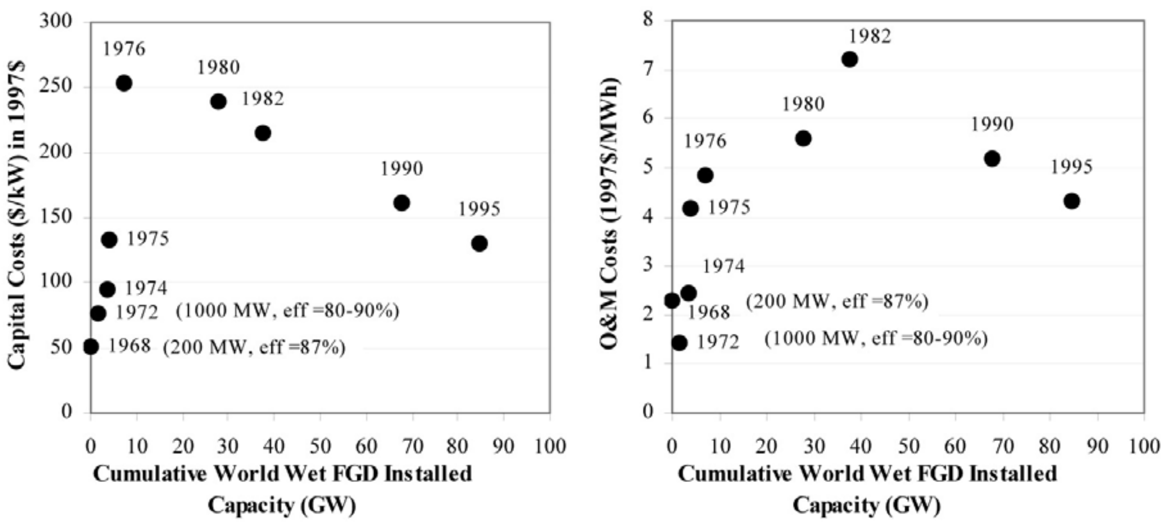

Figure 6-2: Capital and O&M Cost Trends Experienced During the Introduction and Maturation of Wet Flue Gas Desulfurization Technologies[79]

Source: CMU

Figure 6-3 shows the cost trend predictions the CMU team developed for PC, natural gas combined cycle (NGCC), IGCC and Oxy fuel power plants with CO_2 capture. These cost estimates are reported to be comparable to others produced with similar assumptions.

Technology	Cost of Electricity (excl transport/storage)				
	Nominal ($/MWh)			Range ($/MWh)	
	Initial	Final	% Change	Range	% Change
NGCC Plant	59.1	49.9	15.5	46.1 - 57.2	3.2 - 22.0
PC Plant	73.4	62.8	14.4	57.8 - 68.8	6.2 - 21.3
IGCC Plant	62.6	51.5	17.6	46.4 - 57.8	7.7 - 25.8
Oxy fuel Plant	78.8	71.2	9.7	66.7 - 75.8	3.9 - 15.4

Figure 6-3: Forecasted Change in Cost of Electricity after 100 GW Capture Plant Capacity[80]

Assumptions: Capacity ~500 MW; capacity factor 75 percent; 90 percent CO_2 capture; CO_2 product compressed to 13.8 MPa.

Cost and Risk

By any measure, the incremental cost for CO_2 capture is large, and programs to reduce capital costs for IGCC and PC units with CO_2 capture are a primary focus of recommended RD&D. Such RD&D investments are made within a framework that must account for many sources of financial risk, especially when the context is a first-of-kind, commercial-scale demonstration project. Although the technology risk may be the most obvious, a commercial-scale project also is vulnerable to interdependent risks related to public policy, local and international economic climate fluctuation, fuel cost variability, construction cost variability, and the project location within a specific distribution system, environmental paradigm and labor market.

Capital cost is an example of many complex factors that contribute to project risk. As of early 2007, it is very difficult to obtain complete and accurate data for use in preparing current capital cost estimates, much less for accurate forecasts of capital and operating costs for plants that will be built five to 15 years in the future, using technology not yet demonstrated at commercial scale. Investment decisions will be affected by public policy decisions still in early stages of formation. Also, construction costs have increased sharply in the past few years, as shown in Figure 6-4, which plots two common industrial cost indices: the Chemical Engineering Plant Cost Index (CEPCI) and the Marshall & Swift Equipment Cost Index. The sharp increase in the CEPCI index beginning in 2004 was chiefly caused by rising prices for equipment, steel, cement and other commodities, attributed to rising oil prices and heightened worldwide demand for construction of industrial facilities, particularly in Asia. Closer examination of the components of the CEPCI index revealed that construction labor costs were relatively flat until October 2005. Since then, the need to rebuild and repair after hurricanes Katrina and Rita has produced acute shortages in equipment, commodities *and* skilled labor.

> **Capital Cost Uncertainty**
>
> *Since 2004, the rapid escalation of prices for key commodities such as concrete and steel, as well as rising construction labor costs, make current capital cost data difficult to obtain and future costs difficult to forecast.*

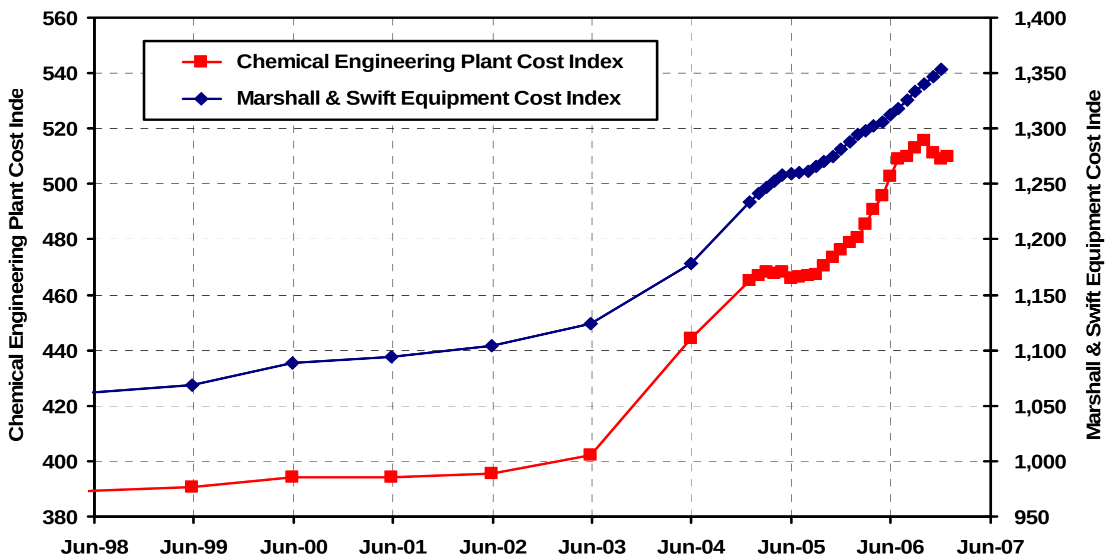

Figure 6-4: Construction Cost Indices[81]
Source: EPRI

EPRI also gains insight into capital cost trends by compiling and reviewing cost data from public announcements and public utility commission filings for new power plant projects. A sampling of these data is shown in Figure 6-5.

Owner	Plant Name/ Location	MW Net	Technology/Coal	Reported Capital Cost $ Million	Reported Capital Cost $/kW
AEP SWEPCO	Hempstead, AR	600	USC PC/PRB	1680	2800
AEP PSO/OGE	Sooner, OK	950	USC PC/PRB	1800	1895
AEP	Meigs County, OH	630	GE RQ IGCC / Bituminous	1300 early 2006 now?	2063 ?
Duke Energy	Edwardsport, IN	630	GE RQ IGCC/Bituminous	1985	3150
Duke Energy	Cliffside, NC	800	USC PC/Bituminous	1930	2413
NRG	Huntley, NY	620	Shell IGCC / Bituminous, Pet Coke, PRB	1466	2365
Otter Tail/GRE	Big Stone, SD	620	USC PC/PRB	1500	2414
Southern Co.	Kemper County, MS	600	KBR IGCC / Lignite	1800	3000

Figure 6-5: Recently Reported PC and IGCC Capital Costs[82]

From PUC submissions and press announcements (does not include carbon capture); many cost estimates are much higher than prior year values

Source: EPRI

EPRI and the National Coal Council recommend that all capital cost values be considered substantially uncertain, whether explicitly stated or not, as there is no consistent basis for the reported costs (i.e., "Total Project Cost" or "overnight dollars" vs. "Total Capital Requirements" or something in between). It also should be noted that plants firing low-rank coals such as Powder River Basin (PRB) typically have higher capital costs and lower fuel costs than plants firing bituminous coals.

Economic Terminology

TPC—Total Plant Cost (TPC), *includes*

- *Process facilities capital*
- *General facilities capital*
- *Engineering and home office overhead including fee*
- *Contingencies—project and process*

TCR—Total Capital Requirement

- *Includes TPC and Owner's Costs*

COE—Cost of Electricity (COE), also known as Levelized Cost of Electricity (LCOE)

- *The net present value of all cost streams associated with a plant over its economic life divided by the total generation in MWh over that period.*

Technology-Based Framework for Cost Reduction and Performance Improvement

Both combustion and gasification options with CO_2 capture can compete with NGCC generation on cost and emissions criteria. Each coal-based technology has general relative advantages, depending on coal properties, ambient conditions and location.

IGCC with carbon capture shows an advantage in most studies for low-moisture bituminous coals with high sulfur content. However, for coals with high moisture and ash content, some studies show pulverized coal with carbon capture being competitive with or having a cost-of-electricity advantage over IGCC. EPRI and the National Coal Council recommend that the assumptions of any study should be carefully reviewed when evaluating its conclusions.

Design and Adaptation for CO_2 Capture and Sequestration

Many different approaches may be taken toward design and investment for CCS. The most cost-effective implementations will involve integrating capture into new state-of-the-art plants that are designed after enough lessons learned from the first several plants.

The installation of CO_2 capture systems on plants designed to be "capture ready" will add costs for lost production and for removal or relocation of existing equipment. Some systems will incur further costs because of design compromises during the original plant design and construction and subsequent technology changes and lessons learned. Others will benefit from lessons learned and be less costly than if commissioned with capture systems installed.

The most challenging and expensive implementations of CO_2 capture and sequestration will be with plants that were designed without consideration for future capture requirements. Creative, awkward and/or expensive fabrication may be required to fit available capture technologies into limited space. Steam requirements will need to be met through turbine and/or steam generator modifications or through inefficient use of higher pressure steam.

Fuel Properties Affect Relative Economics

IGCC with CO_2 capture shows a life-cycle cost advantage in many engineering economic studies for low moisture bituminous coals. However, for coals with high moisture and/or ash content, studies tend to show pulverized coal generation with post-combustion capture as having an edge over IGCC.

"Now or later" decisions will require careful study. In the best case, "watch and wait" may provide the best net present value for a particular plant, with accrued savings in finance costs exceeding the future cost of more expensive modifications. In the worst case, a relatively new plant may become financially obsolete if strict CO_2 emissions controls are implemented and the design does not allow cost-effective capture.

CO_2 "Capture-Ready" Power Plant Designs

The concepts of "capture ready" and "capture capable" have appeared in Congressional testimony, legislation, press announcements and numerous other forums without a clear consensus on their definitions and implications. Many plants being designed now will likely need to convert to CO_2 capture at some point in their lifetimes. It is therefore important to examine which measures are economically justifiable, in the original design, to facilitate future transition to CO_2 capture, considering the uncertainty regarding the type and timing of greenhouse gas legislation.

For IGCC and combustion power plants, pre-investment for future installation of CO_2 capture can be approached in varying degrees. Provision of adaptable space is the most fundamental requirement for making a plant capture-ready. Adequate provision for steam supply, water supply and control system integration also can significantly improve the plant's levelized COE.

CO_2 Capture Options for IGCC Power Plants

IGCC technology has been touted as ideal for CO_2 reduction because the high gasifier pressure allows use of smaller (and less costly) capture systems, using physical solvents (e.g., UOP Selexol®) in lieu of chemical solvents (e.g., amines). The Selexol® process allows CO_2 to be captured at elevated pressure, thereby reducing subsequent compression requirements for capture and sequestration. Also, much of the required technology has been proven in acid gas recovery systems in coal-chemical and petrochemical plants. However, its application for IGCC significantly increases the complexity and cost of the gas clean-up systems and significantly reduces net system efficiency.

> **IGCC Capture Technology**
>
> *IGCC CO_2 capture technologies have been proven in acid gas recovery systems in coal-chemical and petrochemical plants.*

Three general levels of capture can be designed for in IGCC plants.

- For slurry-fed gasifiers, the CO_2 in the syngas can represent 20-25 percent of the coal's carbon that could be removed without using the water-gas shift reaction. Although this relatively small amount of capture is unlikely to generate much interest from federal or state authorities seeking to make significant reductions in CO_2 emissions, it could be of some value for relatively low-cost production of CO_2 for enhanced oil recovery (EOR) or other use.
- All gasification technologies can use a sour high-temperature shift followed by a two-column acid gas removal (AGR) unit (also known as "gas clean-up"). The syngas may still be able to use standard syngas CT combustors. This could result in 60-80 percent CO_2 capture, which would easily satisfy California's criterion that CO_2/MWh not exceed that from NGCC.
- If >90 percent removal is required, both high- and low-temperature shift beds are necessary. However, this would require CT combustors designed for hydrogen.

One main contributor to the additional cost of capture with IGCC is that no air extraction is possible when firing hydrogen in GE 7FA and 7FB gas turbines. Although there is added capital for the shift, CO_2 removal and compression, the major increase in TPC $/kW net results from the additional main air compressor (MAC) capacity required for capture, because no air is available to the air separation unit (ASU) from the CT compressor. It is not yet clear if the Siemens turbines will have the same limitation.

IGCC Pre-Investment Options for Later Addition of CO_2 Capture

Most IGCC designs evaluated in previous studies have incorporated capture in the initial designs. However, in view of the uncertainty – at least in the United States – of CO_2 regulations, it is probably more appropriate to consider the addition of capture to an IGCC design initially without capture or with various degrees of pre-investment. Depending on the owner's perception of the extent and timing of potential regulation, various degrees of pre-investment may be appropriate to optimize the plant output and performance over time.

Several pre-investment options can be considered for later addition of capture:

- **Standard Provisions.** Leave space for additional equipment and tie-ins, balance of plant (BOP) and site access at later date. Conversion to capture imposes a net power capacity, efficiency and cost penalty.
- **Moderate Provisions.** Additional ASU, gasification and gas clean-up are needed to fully load the CTs when water-gas shift is added. If this over-sizing is included in the initial IGCC investment, the capacity can be used in the pre-capture phase for supplemental firing or co-production. This version of "capture ready" would then permit full CT output with hydrogen (at International Organization for Standardization [ISO] conditions) when capture is added. The cost and efficiency penalties are mitigated. However, when shift is added, considerable modifications to the acid gas removal unit will be required.
- **Extensive Provisions.** In this option, the pre-investment design is with conversion-shift reactors, oversized components and an AGR absorber sized for shifted syngas, but no CO_2 absorber and compressor. There should be no need for a major shutdown to complete the conversion to CO_2 capture.

When the shift reaction is added to a design, the dry gas flow to the AGR is increased markedly, although not equally for all technologies. The dry gas flow increases by about 45 percent for GE and ConocoPhillips E-Gas systems and by about 60 percent for Shell.

CO_2 Capture Options for Coal Combustion (PC and CFBC Plants)

Post-combustion capture of CO_2 is offered commercially, for advanced PC technology and for supercritical-circulating fluidized bed combustion (SC-CFBC) technology, but has seen only limited implementation to date. Although in theory a commercial-scale PC plant with CO_2 capture could be built today, it would involve considerable scale-up at a high capital cost and with a major increase in heat rate; levelized COE would be very high. Improvements in absorption and adsorption technologies have been demonstrated at pilot scale and promise reduced CO_2 capture cost in the intermediate timeframe if major RD&D investments are made. Recommended research areas include chilled ammonia, improved amines and other solvents, along with molecular sieve ceramics and other solids.

In the United States, three coal-fired CFBC facilities are recovering CO_2 at small scale using a MEA (monoethanol amine) solvent process.[83] AES Warrior Run in Maryland and AES Shady

Point in Oklahoma sell CO_2 as a food-grade product. The IMC Chemicals West End facility in California uses the CO_2 as a feedstock to produce soda ash. This plant recovers 300 metric tons/day, which equals the CO_2 produced in a 15 MW_e power plant.[84]

Growing industry interest has led to plans for a number of pilot plant projects and engineering feasibility studies for several commercial-scale plants over the next several years.

- EPRI and Alstom are sponsoring a 5 MW_{th} chilled ammonia pilot at the We Energies Pleasant Prairie Power Station (Wisconsin).
- Air Products, Air Liquide, Alstom, Babcock & Wilcox (B&W) and others are working on pilot-scale boilers with capture.
  - CANMET (~1 MM/Btu/hr, 0.3 MW_{th})
  - B&W (~5 MMBtu/hr, 1.5 MW_{th})
  - Alstom CFBC (2.6–7.4 MMBtu/hr, 0.7–2.2 MW_{th})

Oxy fuel combustion, with capture by compression, is also under consideration for advanced PC and CFBC plants, but is not as advanced as IGCC and PC with capture. Because the economics have not yet been well defined, the ultimate competitive position is not well defined with respect to PC/CFBC technologies with post-combustion capture. Plans have also been announced for two significant Oxy fuel pilot demonstration plants and one major project:

- B&W is converting a 30-MW_{th} research combustor in Alliance, OH, to an Oxy fuel pilot to collect data for the SaskPower project (see below).
- Vattenfall announced plans for 30-MW_{th} (< 10 MW_e) Oxy fuel demo near Schwarze Pumpe, Germany.
- SaskPower has announced plans for a 300-MW_e Oxy fuel power plant in Saskatchewan:
  - CO_2 would be sold for enhanced oil recovery.
  - The project is on fast track to be in service by 2011.

PC and CFBC Pre-Investment Options for Later Addition of CO_2 Capture

For PC and CFBC plants, later addition of capture is much simplified with a modest amount of attention to equipment and process requirements for installing a capture system.

- **Standard Provisions.** Leave space between the flue gas desulfurization unit and the induced draft fan for additional equipment and tie-ins, balance-of-plant equipment and site access at later date. Conversion to capture imposes a net power capacity, efficiency and cost penalty.
- **Moderate Provisions.** Design the flue gas ducting with a blank spool so a solvent contact system can be installed as a simple replacement section. Install several steam turbine extraction ports to allow a choice of auxiliary steam supply pressures.

Comparative Studies with and without Capture for IGCC and PC Generation

Several government and industry studies have attempted to forecast cost and other impacts of adding CO_2 capture to existing plants and to new plants which are originally designed for capture or designed to facilitate retrofit at a later date. In reviewing these studies, it becomes clear that while useful for providing a rough understanding of future plant costs, current knowledge is not yet sufficient to indicate a clearly preferable choice between gasification and combustion technology when capture is required. As is shown in Figure 6-6, the range of uncertainty about the COE for a given technology may exceed the difference between the median estimates for different technologies. The selection of location and fuel may change the conclusion for a plant to be built in the near future. For a more distant timeframe, different assumptions related to the timing of government mandates, variations in the rate of development of different technologies, and economic factors such as the cost of coal and cost of metals may make one or the other technology appear preferable.

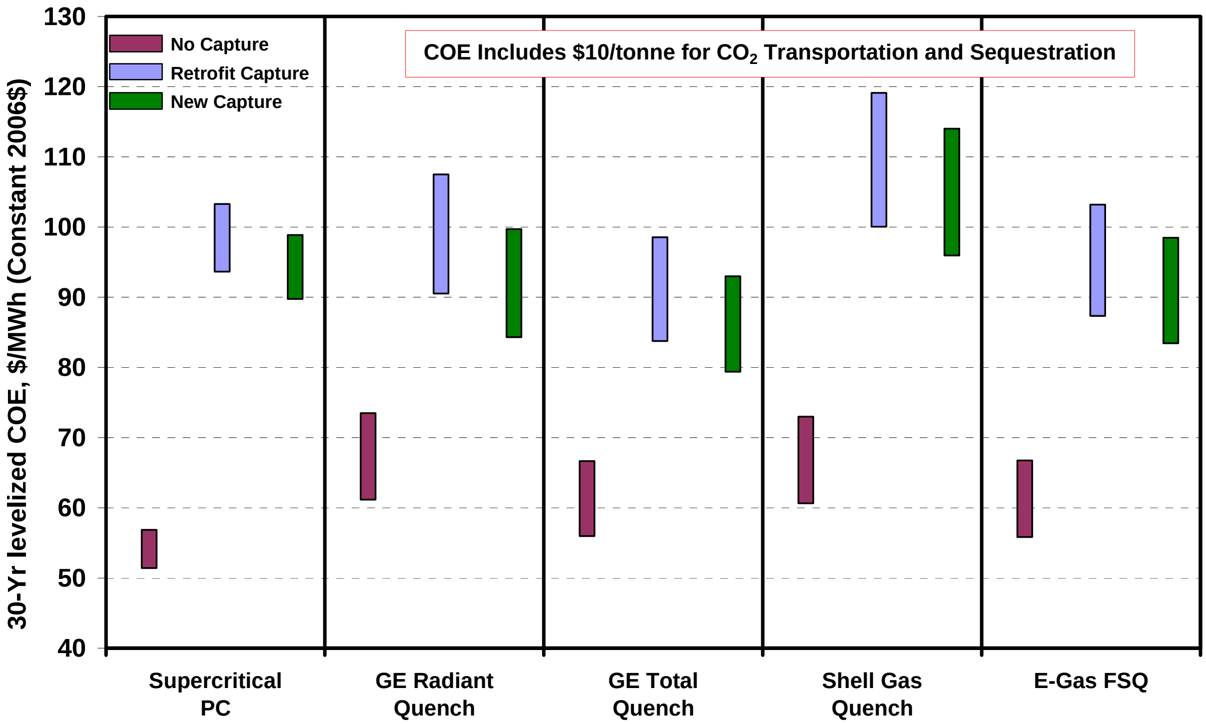

Figure 6-6: EPRI Estimates: PC and IGCC Cost of Electricity with and without CO2 Capture (Illinois #6 Coal)[85]

(All IGCC and CCS cases have +10% TPC Contingency for First-of-a-Kind)

DOE Study – IGCC versus PC (for Bituminous Coal) versus NGCC

Preliminary results from DOE National Energy Technology Laboratory (NETL) work in preparation of the newly released report, *2006 Cost and Performance Baseline for Fossil Energy Power Plants: Volume 1, Bituminous Coal and Natural Gas to Electricity*, were presented at the

2006 Gasification Technologies Conference (see Figure 6-7**).** The DOE study predicted relative performance and cost for IGCC, PC and NGCC plants without and with CO_2 capture.

For the IGCC and NGCC cases, DOE estimated performance and efficiency for units employing two GE 7FB CTs and one steam turbine. DOE examined PC cases with both subcritical (2400 psig/1050°F/1050°F) and supercritical (3500 psig/1100°F/1100°F) steam conditions.

The CO_2 capture cases are based on units designed for capture from their inception. For IGCC, this assumed larger gasifiers able to keep the CTs at full load when firing hydrogen-rich syngas. (Note: The water-gas shift reaction reduces the energy content of syngas by about 10 percent.) As output is limited by the choice of CT, net plant output for the capture cases is reduced by the parasitic loads for solvent regeneration, pumping, compression, etc. (For a retrofit, the unit would see a relatively greater reduction in net power output and a higher levelized COE.) In contrast to the IGCC cases, which are constrained by available CT offerings, PC designs with post-combustion amine scrubbing for CO_2 capture were sized with larger boilers and steam turbines so the net output of the "with capture" plants was the same as the PC designs without capture. For NGCC, the post-combustion capture process was the same as that used for the PC designs (Fluor Econamine). As with IGCC, net output is limited by CT design parameters.

Technology	IGCC						PC				NGCC	
Metric	GE Energy		CoP E-Gas		Shell		Subcritical		Supercritical		2 x 7FB	
Case #	w/o Capt	with Capt	w/o Capt	with Capt	w/o Capt	with Capt	w/o Capt	with Capt	w/o Capt	with Capt	w/o Capt	with Capt
Gross MW	769	7419	7349	6809	7396	667						
Net MW	644	563	612	515	6205	501						
HHV Effic'y	38.6%	32.6%	38.5%	36.3%	40.3%	30.6%	36.3%	23.9%	38.5%	26.9%	50.6%	43.4%
TCR, $/kW	1730	2166	1576	2068	1770	2500	1474	2626	1508	2635	568	988
LCOE, $/MWh	56.9	70.5	51.5	66.3	56.1	77.2	49.9	86.3	49.7	83.5	67.5	89.9
% Increase in COE with Capture		23.9%		28.7%		37.6%		72.9%		68.0%		33.2%

Assumptions: January 2006 dollars; 13.8% levelization factor; coal cost $1.34/MMBtu-(HHV); gas cost $7.46/MMBtu-(HHV); capacity factors: IGCC – 80%; PC – 85%; NGCC – 65%

Figure 6-7: DOE NETL Cost Estimates for IGCC, PC and NGCC, with & without CO_2 Capture, using Illinois #6 Coal[86]

EPRI credits DOE with undertaking one of the most comprehensive recent studies. While noting that DOE's preliminary COE values in Figure 6-7 seem to be low, EPRI feels the relative cost differences (in percentage terms) are largely valid. In the case of supercritical PC with capture, some studies (including those by EPRI and IEA) have included modest process enhancements that increase initial cost but reduce levelized COE through efficiency improvement – resulting in a net COE increase for adding CO_2 capture on the order of 60 percent. [Note: Report DOE/NETL-2007/1281 was issued just as this report was sent to press. The values shown in Figure 6-7 have been updated.]

CPS Energy Study – IGCC versus PC for PRB Coal with Retrofit for CO_2 Capture

A study funded by CPS Energy and performed by Burns & McDonnell, with assistance from EPRI, was one of the first to evaluate the retrofit of capture to IGCC and SCPC plants designed in a pre-capture era. This reflected imminent needs for new capacity and less well-defined expectations regarding future mandates for CO_2 capture. Most previous studies of IGCC and PC plants had evaluated designs with capture included from the beginning. This study is also one of the few to compare IGCC and PC plants using sub-bituminous coal.

> **CPS Study — CO_2 Capture Retrofit for IGCC versus SCPC Using PRB Coal**
>
> *Although the difference between the lifecycle cost (expressed as COE) for IGCC and SCPC decreases when capture is added, the SCPC COE remains approximately 5 percent less than that for IGCC.*

This feasibility-level study addressed future addition of CO_2 capture systems to IGCC and SCPC plants, which were assumed to have been constructed in the very near term at a Texas coastal location. Each plant was assumed to have 550 MW net output using PRB coal with a delivered cost of $1.65/MBtu (HHV). An additional IGCC case assumed a plant initially designed to use a 50/50 by weight blend of PRB and petroleum coke (delivered cost of $1.12/MBtu). The IGCC cases assumed use of Shell gasification technology, Selexol®-based AGR and GE 7FB gas turbines in a two-on-one configuration. The SCPC case assumed steam conditions of 3500 psig/1050°F/1050°F.

The IGCC retrofit case for 90 percent CO_2 capture included replacement of COS/HCN hydrolysis reactor with two stages of "sour shift" reaction, additions to syngas cooling trains for the shift reactors, additions to the Selexol® AGR to recover CO_2 as a separate by-product, and upgrade of the demineralizer water treatment and storage system for 450,000 lb/hr intermediate pressure (IP) steam for water-gas shift.

Case Description	Shell IGCC 100% PRB	Shell IGCC 50/50 PRB/Pet Coke	SCPC 100% PRB	Shell IGCC 100% PRB with Capture	SCPC 100% PRB with Capture
Gross MW	710	711	615	630	521
Auxiliary Load MW	157	158	65	217	132
Net MW	553	553	550	413	390
Heat Rate Btu/kWh (HHV)	9220	9070	9150	12,800	12,911
Availability %	85	85	90		
TPC $/kW	2390	2330	1950	3630	3440
TCR $/kW	2670	2580	2190	4040	3840
20 year LCOE $/MWh 2006$	45.0	40.9	39.2	65.4	62.0

Figure 6-8: CPS Energy Evaluation of Shell IGCC and SCPC, PRB coal, Texas[87]

(Cost basis is U.S. dollars, mid-2006)

Source: EPRI

As with the DOE study, the cost of adding capture was greater for the PC plant than for the IGCC plant. The data in Figure 6-8 show the COE for SCPC remains approximately 5 percent less than that for IGCC. This suggests that for PRB coal, even with implementation of CO_2 capture, a PC power plant *may* have an economic advantage over an IGCC plant. (Note: In EPRI's initial analysis, certain IGCC design choices resulted in a suboptimal Selexol® application. An optimized application, or an alternative to Selexol®, may improve the economics of IGCC with CO_2 capture. EPRI may revise its analysis and issue a supplemental report in 2007. The broader conclusion – that for a PRB-based plant with CO_2 capture, both IGCC and SCPC are competitive – is expected to remain unchanged.) However, as is illustrated in Figure 6-9, the range of uncertainty for both estimates exceeds the difference between them. Similarly, Figure 6-10, based on the IEA and DOE studies that assumed smaller ranges of uncertainty, shows that even with bituminous coal, IGCC or SCPC both may show better COE performance, depending on specific choices of technology, future timing of technological improvement and cost reductions, and other factors such as location, commercial conditions and fuel costs.

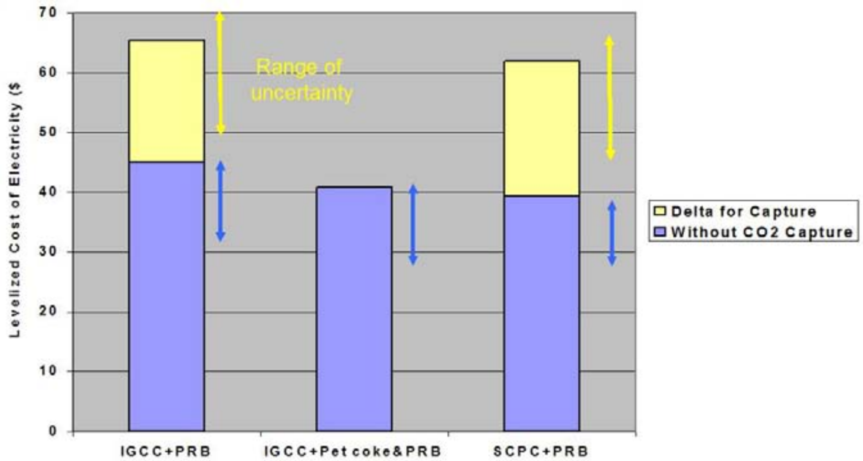

Figure 6-9: COE for IGCC and PC Using PRB Coal, with and without CO_2 Capture[88]

Source: EPRI

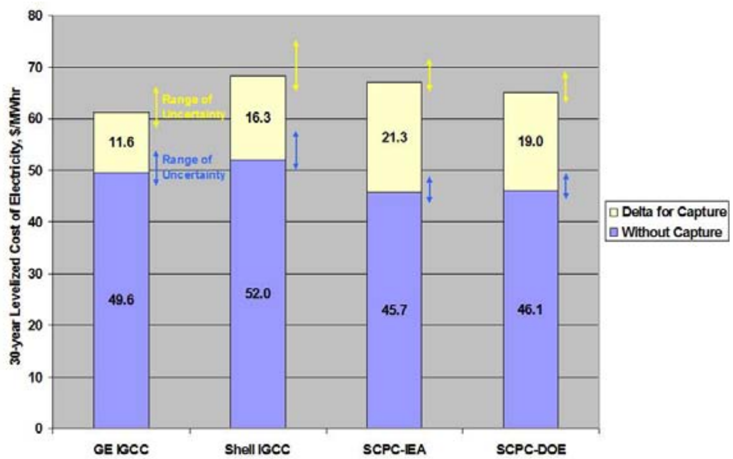

Figure 6-10: COE for IGCC & PC; Bituminous Coal; with and without CO_2 Capture[89]

IEA & DOE bituminous coal adjusted to standard EPRI economic inputs: $2/MMBtu coal, 85% capacity factor, 2005 USD.

The key lessons from these studies is that it will be possible to retain cost-effective coal-based power generation while achieving CO_2 reduction goals, and that eventual success will require significant, well-targeted investment to develop and refine key enabling technologies.

With this in mind, CURC and EPRI formulated the critical net efficiency and cost goals into a Roadmap. Meeting the goals of the Roadmap will result in significant progress in reducing CO_2 production by coal-based power generation. Still, capture and sequestration will be necessary if aggressive (i.e., >90 percent) reductions of CO_2 emissions are to be achieved.

For IGCC, the technology advances required to meet the CURC-EPRI targets constitute a substantial part of the solution. Additional efforts for CO_2 capture with IGCC will focus on adapting CTs for use with hydrogen-rich fuels and on cost-effective integration of capture technologies that chemical industries have developed for coal- and petroleum-based gasification systems.

For coal combustion technology with CO_2 capture, life-cycle cost ultimately will depend more on improved solvent processes than on improving plant reliability or improving heat rate through use of advanced steam conditions (though these, too, are important). The introduction of Oxy fuel combustion may allow further reduction in capture costs by allowing direct compression along with a reduction in the size of the supercritical steam generator.

Technology Maturity and Opportunities for Cost Reduction

As summarized in Figure 6-11, gasification- and combustion-based technologies for power generation offer an interesting contrast in opportunities for cost reduction.

Base Plant Technology	Overall Technology Maturity	Capital Cost Trend for Plant Technology	CO_2 Capture Technology Maturity	Capital Cost Trend for CO_2 Capture
PC	Very mature	Not decreasing much by now	Very immature	Can expect reasonably steady, perhaps large, decreases in cost
IGCC	Youthful, bordering on immature	Can expect decreases as more plants come online	Capture technology is mature, but requires H_2-fired CTs, which are not yet proven	Significant cost reduction requires revolutionary process change (e.g., membrane separation or fuel cells)

Figure 6-11: Trends in Maturity and Cost of Plant Technology and CO_2 Capture Technology[90]
Source: EPRI

As shown, combustion-based generating technologies are quite mature, but much improvement is needed to cost-effectively capture CO_2 from the flue gases. For IGCC, CO_2 capture can be performed efficiently at high pressure using technologies with extensive chemical industry experience. The base IGCC technology, however, still requires much work to improve reliability, availability, capital cost and thermal efficiency.

EPRI and others do not forecast large decreases in the capital cost of the traditional boiler (steam generator), turbine and balance-of-plant “islands.” Conventional SCPC technology and subcritical CFBC technology are now used widely, and ultra-supercritical (USC) PC has been introduced in Europe and Asia. The first major commercial SC-CFBC plant is nearing completion in Poland. Future COE improvements are expected to be realized primarily through efficiency gains, not through capital cost reduction, though construction optimization promises cost reductions of up to 10 percent. Conversely, existing processes for post-combustion CO_2 capture are only cost effective for specialized, smaller scale applications. Considerable scale-up is required before they can be implemented on new PC and CFBC units. Near-term developments are promising, with several new capture technologies moving from the lab to pilot scale projects. Thus, EPRI believes there is considerable potential for significant technology development and refinement that will reduce the incremental cost of post-combustion CO_2 capture from PC and CFBC power plants.

It should be noted that the economic evaluations in the various studies for post-combustion capture of CO_2 were based on an upgraded version of the long-established MEA-based chemical solvent process. Figure 6-12, which is also based on a study addressing bituminous coal, illustrates how improved solvents are expected to greatly reduce post-combustion CO_2 capture cost compared to conventional MEA-based technology. Figure 6-12 also provides a forecast for COE for advanced USC (1400°F; double reheat) with CO_2 capture as the technology approaches maturation. This figure depicts expected cost reductions attainable through improved solvents for post-combustion capture. The data suggest that solvent advances will have a greater impact on reducing the cost of CO_2 capture than does the incremental reduction of capture requirements by improving heat rate through advanced steam conditions.

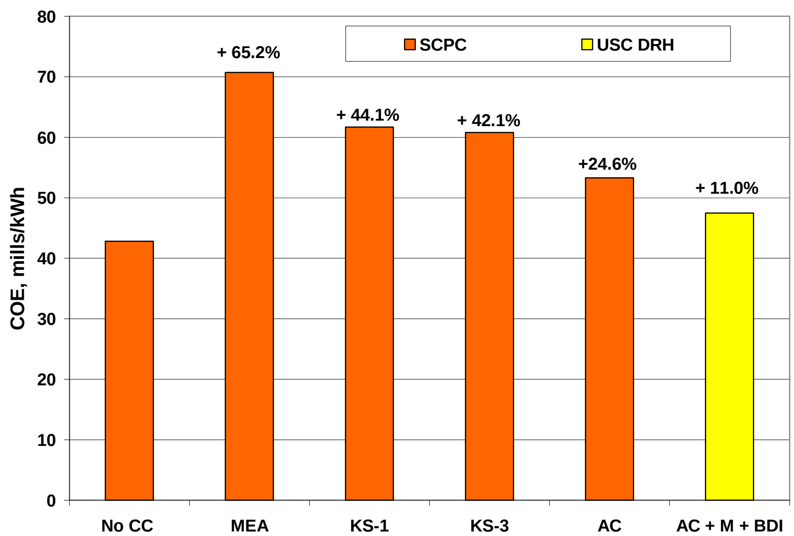

Figure 6-12: Effect of Post-Combustion CO_2 Capture on COE Using Pittsburgh #8 Coal[91]
Source: EPRI

Figure 6-12 Notes:

- Boilers have enhanced environmental controls to minimize particulates, SO_2 and NO_X in flue gas entering the CO_2 capture plant.
- The base case and absorption cases assume SCPC steam conditions of 3615 psia/1050°F/1050°F. Ninety percent CO_2 capture is assumed for all cases.
- Levelized COE is in 2003 dollars for a 30-year book life. The coal cost is $1.50/MBtu. Location: Kenosha, Wisconsin. TPC is in 2003 dollars.

- The data point for MEA CO_2 solvent is based on an early system design with four absorbers, four strippers and one compressor that has relatively poor heat utilization. As a result, it overestimates the cost premium for implementing CO_2 capture on SCPC systems.
- KS-1 and KS-3 are "hindered amine" CO_2 solvents offered by Mitsubishi Heavy Industries that have lower heats of regeneration than MEA. The system design with these solvents used two absorbers, two strippers and one compressor, and incorporated several heat utilization improvements.
- Ammonium carbonate (AC) CO_2 solvent allows for regeneration at 300 psia, reducing size of stripper, compressor and compressor power. The system design for this case used two absorbers, one stripper and one compressor.
- The USC double reheat (DRH) case assumes use of AC solvent and incorporation of boiler design improvements, such as reduced steam line lengths. The absorber and stripper tower designs used in the other cases are assumed to have been superseded by more cost-effective membrane contactors. It is also assumed that material advances will allow USC DRH steam conditions of 5015 psia/1360°F/1400°F/1400°F.

Oxy fuel combustion technology has much further to go to become established. This technology promises eventually reducing the COE of PC and CFBC plants *with capture* by reducing the capital and operating costs of the steam generator and CO_2 capture equipment. Oxy fuel will incur significant costs with the addition of oxygen supply technology, an area that also requires improvement in cost and efficiency (for example, through use of ion-transfer membranes) for IGCC and other industries.

The situation for IGCC technology is nearly the opposite. Considerable capital savings are expected to accrue through higher capacity and higher pressure gasifiers, new combustion turbine models, improved oxygen supply technologies and better plant integration. On the other hand, CO_2 capture processes for IGCC units are relatively well established. Eastman Chemical, Ube Ammonia and Dakota Gasification, for example, have been using water-gas shift followed by CO_2 removal processes since the early 1980s. After upgrades completed in 2000, Dakota Gasification is now selling CO_2 for enhanced oil recovery. Many chemical plants (although not coal-based) use water-gas shift for CO_2 production. Selexol® is used for CO_2 capture and acid gas clean-up in more than 30 commercial installations around the world. Still, optimization opportunities for IGCC designs with integrated CO_2 capture are expected to provide significant reductions in capital cost and levelized COE.

CO_2 sequestration faces comparable challenges and opportunities. Basic technologies for geologic exploration, well drilling and completion, and pipeline construction and operation are very mature. Much is still to be learned about the physical and chemical interactions of high-pressure CO_2 within different storage zone structures and chemistries. For CO_2 sequestration, however, the greatest challenges may be at the public policy level, where resolution of monitoring, regulatory and liability issues is needed before significant investment is likely to occur in long-term geologic storage.

Comparison of Baseline Technologies and Performance Targets

Useful targets for measuring progress in development of advanced coal generation technologies are provided in the joint CURC-EPRI Roadmap published in 2002 and updated in 2006.[92] The CURC-EPRI targets bring insights from many experts into a consensus forecast of what will be required by regulatory bodies and what can be achieved by industry if adequate resources are provided.

The expected values for the IGCC and SCPC baseline designs are presented in Figure 6-13, along with the 2020 goals for coal power plants contained in the updated CURC-EPRI Roadmap (additional goals address criteria pollutants). For IGCC, reaching these technology-neutral targets will require significant RD&D progress toward improving availability and thermal efficiency and reducing capital cost. For PC, advances are expected in the areas of thermal efficiency and environmental controls.

Technology	Coal Type	Availability	Thermal Efficiency, HHV basis	Capital Cost, $/kW 2Q 2005 USD
SCPC 2004	Pitts #8	86%	38.8%	1437
IGCC 2004	Pitts #8	80–85%	38.9–40.4%	1509–1761
CURC-EPRI Roadmap for 2020	Pitts #8	90%	42–46%	1220–1350
SCPC 2004	PRB	86%	37.6%	1552
IGCC 2004	PRB	80–85%	35.7–40.2%	1536–1832
CURC-EPRI Roadmap for 2020	PRB	90%	42–46%	1220–1350

Figure 6-13: Comparison of 2004 Baseline Designs to CURC-EPRI Targets for Coal Power Plants in 2020[93]
Source Data: CURC-EPRI

RD&D Needs for Coal-Based Generation

Assuring cost-effective coal power technology that incorporates CO_2 capture entails simultaneous achievement of substantial progress in RD&D efforts for capture processes and for fundamental plant systems. Figure 6-14 shows a timeline for IGCC RD&D goals that were identified by EPRI's *CoalFleet for Tomorrow* collaborative research program. This diagram shows the expected timeframe for key technology development and full-scale demonstration, along with goals for overall plant cost and efficiency. Figure 6-15 shows a comparable timeline for PC power plants. In both charts, key technologies for CO_2 capture are shown as longer term goals. Blue arrows indicate plant cost trends while green arrows represent efficiency trends.

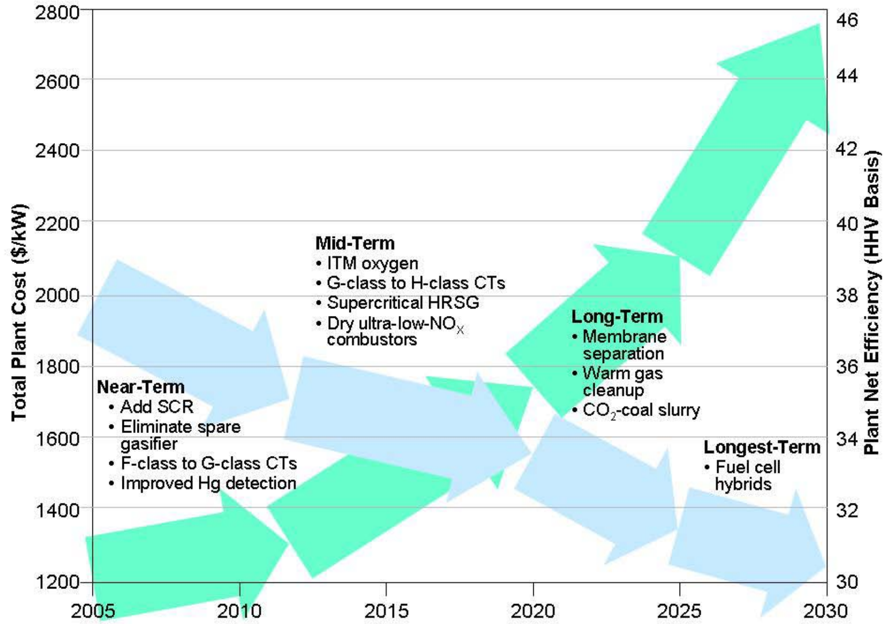

Figure 6-14: Forecast Reduction in Capital Cost and Improvement in Efficiency through Implementation of an IGCC RD&D Augmentation Plan[94]

(Slurry-fed gasifier, Pittsburgh #8 coal, 90% availability, 90% CO_2 capture, 2Q 2005 U.S. dollars)

Source for both charts: EPRI

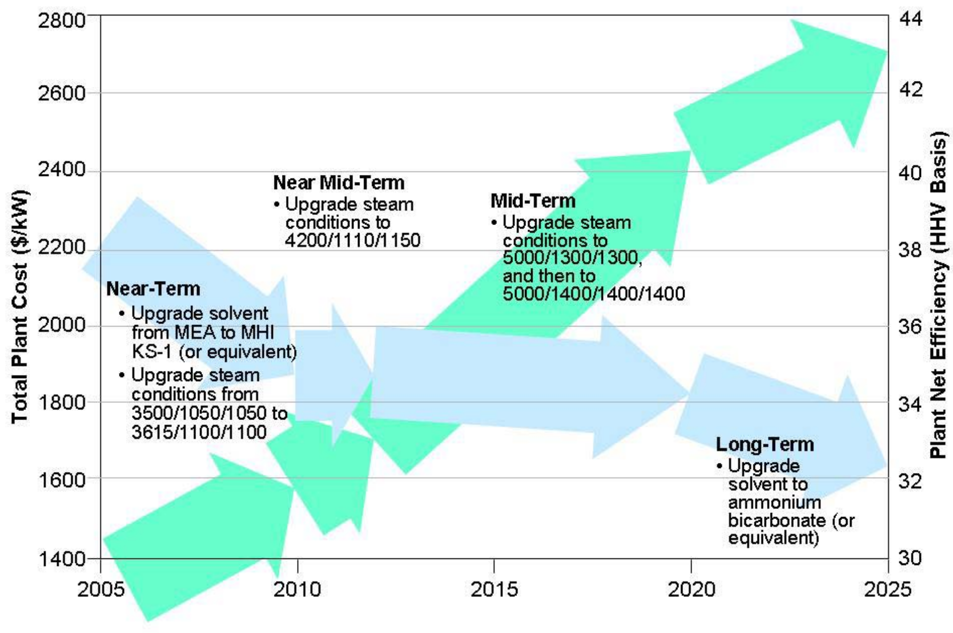

Figure 6-15: Forecast Reduction in Capital Cost and Improvement in Efficiency through Implementation of a USC PC RD&D Augmentation Plan[95]

(Pittsburgh #8 coal, 90% availability, 90% CO_2 capture,
as-reported data from various studies [not standardized])

Stakeholder Roles in Advanced Coal RD&D

> **Stakeholder Cost Share**
>
> *Collaborative RD&D efforts (i.e., public-private partnerships) provide a way to share the cost and risk of technology development among all the stakeholders, including the public, who will benefit from advanced technology introduction.*

CURC, EPRI, DOE and others have established technology roadmaps, RD&D augmentation plans and other guidance documents seeking to marshal stakeholders from private industry, public agencies and nonprofits to cooperate and collaborate on vital advanced coal RD&D. Such plans facilitate communication to help technology developers, technology users and government RD&D sponsors gain a common understanding of research priorities.

CURC and EPRI have suggested the most appropriate entity or entities to lead various proposed RD&D projects and programs. For example, technology suppliers are clearly the most appropriate entities for projects that involve highly proprietary technology, such as multi-pollutant controls for treating PC exhaust gases. For projects of a more fundamental nature, especially large projects with a significant public good component, government entities such as DOE may appropriately take the lead role. For projects that will yield technology that could be widely applied by all equipment suppliers and buyers, an industry-led RD&D collaborative is logical.

CONCLUSIONS

- Analysis of the current state of CCS technology provides optimism that necessary advances can be made to meet goals for CO_2 capture and sequestration, but also emphasizes that success will require a stronger and more concerted and collaborative effort than is currently under way.
- Achieving greenhouse gas emissions reduction goals will require a broad suite of advanced coal and CCS technologies that can be tailored to the conditions of each individual geographic location, electricity market structure, fuel source, etc.
- IGCC. RD&D plans for IGCC with CO_2 capture provide a pathway toward realization of a roughly 30 percent reduction in the capital cost over the next 20 years on a constant dollar basis, while increasing net efficiency by 9 percentage points.
    - The CO_2 capture process for gasification is considered commercially mature since it uses technologies that chemical industries have already developed for acid gas cleanup in coal- and petroleum-based gasification systems and in natural gas processing. However, using those technologies at large scale in IGCC power plants still constitutes a first-generation application. The technology has not been completely and efficiently integrated into a large-scale power plant and CCS system. Furthermore, hydrogen turbines have not yet been demonstrated in commercial-scale IGCC applications.
    - The base IGCC technology is commercially available, but will benefit significantly from an accelerated RD&D effort to achieve efficiency, reliability and availability improvements, which also are required to meet the CURC-EPRI targets for pre-capture systems. Additional efforts will focus on adapting

combustion turbines for use with hydrogen-rich fuels and on cost-effective integration.

- Pulverized Coal. Current RD&D plans for advanced PC generation with CO_2 capture provide a pathway toward realizing a 30 percent reduction in the capital cost over the next 20 years on a constant dollar basis, while increasing net efficiency by 12 percentage points.
  - For PC and CFBC technology with CO_2 capture, significant cost and performance improvements will need to come from work to improve energy-consuming solvent processes that separate carbon from exhaust streams. Current processes have high capital costs and high auxiliary power or steam demand.
  - Significant CO_2 management gains and cost reductions can also be achieved by improving the efficiency of the generation system with ultra-supercritical pulverized coal combustion and supercritical circulating fluidized bed combustion technology.
- Regardless of the technology, experience teaches us that early in the development of new technologies, we often underestimate the costs and construction lead times for initial full-scale projects. Although engineering-economic studies of advanced coal and CCS technologies attempt to allow for this phenomenon, initial full-scale applications may prove to be more costly than expected. Eventually, accumulation of lessons learned will bring substantial improvements in performance, reliability and cost.
- For many of these technologies, timely attainment of the desired developments will require significant public policy and funding support to enable collaborative initiatives involving power producers, equipment manufacturers, government agencies, academic research organizations and others. Key elements include:
  - predictable policies,
  - sharing of cost and schedule risks,
  - accelerated publication and incorporation of lessons learned.

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[94] Ibid.

[95] Ibid.

SECTION SEVEN

Groups Engaged in Technology Development

FINDINGS

- There is a substantial and rapidly growing international interest and cooperation in practical and economical technologies to reduce carbon dioxide (CO_2) emissions from coal-fueled power plants.
- In the United States, the leading government agency supporting development of relevant technologies is the Department of Energy (DOE), which has programs in three broad areas:
    - The base research and development program,
    - The Clean Coal Technology demonstration programs, and
    - The FutureGen initiative.
- Beyond the federal government's actions, several private organizations in the U.S. are engaged in efforts on carbon management for coal-fueled power plants on both the technical level, for example, the Electric Power Research Institute (EPRI), and the research policy level, such as the Coal Utilization Research Council (CURC).
- State and local involvement in technology development has been principally through participation in federal programs, such as the Regional Carbon Sequestration Partnerships (RCSPs), but several states are supporting research or providing policy incentives for the deployment of advanced coal technologies.
- Significant efforts under way include international participation in several U.S. initiatives, including FutureGen, the Carbon Sequestration Leadership Forum, the Asia Pacific Partnership and the Greenhouse Gas Programme of the International Energy Agency.
- A number of international efforts are under way to demonstrate advanced clean coal technologies for integrating electricity generation with carbon capture and storage (CCS). The timeframe for these is similar to that of the U.S. FutureGen project, with operations expected between 2010 and 2015.

Overview

This section will describe the work the major entities in the United States and elsewhere are doing or coordinating on coal-related carbon management research and development. This is not a comprehensive review, and references are provided to more complete information on some activities rather than a detailed description.

Interest in CCS research began relatively recently and has accelerated in the last few years. Notably, as recently as FY2000, the DOE fossil energy budget request did not include a separate line item for CCS research. Since then, the budget has come to be dominated by funding for technologies that directly or indirectly relate to greenhouse gas management. As shown below, almost 80 percent of DOE's FY2008 coal research and development program budget request of $426 million is greenhouse-gas related.

GHG-Related Program Areas	FY 2008 DOE Funding Request ($MM)
Carbon Sequestration (including capture)	79
IGCC and Advanced Turbines	72
FutureGen Project	108
Fuel Cells	62
Hydrogen from Coal	10
Total	331

Figure 7-1: DOE 2008 Coal Research and Development Budget Request

There has been a similar upsurge of international research and development on carbon management for coal-based emission sources, including a number of multi-national programs and projects to advance carbon capture and storage technology. The DOE program, other domestic (U.S.) activities and an illustrative selection of international efforts are discussed below.

U. S. Department of Energy

Carbon Capture and Storage Research

CCS research, development and demonstration (RD&D) funded by DOE is managed by the National Energy Technology Laboratory's (NETL's) Strategic Center for Coal. CCS RD&D at NETL has the following principal technological goals:

- Develop instrumentation and measurement protocols for direct sequestration in geologic formations and for indirect sequestration in forests and soils that enable implementation of wide-scale carbon accounting and trading schemes.
- Demonstrate large-scale carbon storage options (> 1 million tons/year) for value-added (enhanced oil, coalbed methane and gas recovery) and non-value added (depleted oil/gas reservoir and saline reservoir) options.
- Develop to the point of commercial deployment systems for advanced indirect sequestration of greenhouse gases
- Develop instrumentation and protocols to accurately measure, monitor and verify (MMV) carbon sequestration in terrestrial ecosystems and geologic reservoirs. MMV systems should represent no more that 10 percent of the total sequestration system cost.
- Develop to the point of commercial deployment systems for direct capture and sequestration of greenhouse gases and criteria pollutant emissions from fossil fuel conversion processes.
- Provide a portfolio of commercial ready sequestration systems and breakthrough technologies that have progressed to the pilot test stage for the 2012 assessment under the Global Climate Change Initiative.

The DOE website contains a database of current RD&D projects[96] categorized by program topic. The relevant categories of RD&D for greenhouse gas management through efficiency improvement and carbon capture and storage are:

- Carbon Sequestration RD&D (90 projects)
- Gasification Technologies (46 projects)
- Turbine and Heat Engine Technologies (51 projects)
- Fuel Cell Technologies (93 projects)

The DOE/NETL website[97] provides a detailed list of the carbon capture and storage projects and organizations conducting them, along with program area overviews, budget information, project locations, etc.

Regional Carbon Sequestration Partnerships

One key element of DOE's carbon sequestration research program is a nationwide network of "regional partnerships" formed to help determine the best approaches for capturing and permanently storing gases that can contribute to global climate change, recognizing that opportunities and challenges for carbon storage may differ by geographic region of the country. The Regional Carbon Sequestration Partnerships are members of a government/industry effort charged with determining the most suitable technologies, regulations and infrastructure needs for carbon capture, storage and sequestration in the different areas of the country.

Geographic differences in fossil fuel use and potential storage sites across the United States dictate regional approaches to sequestration of CO_2 and other greenhouse gases. The seven partnerships that currently form the RCSP network include over 300 state agencies, universities and private companies, spanning 40 states, three Indian nations and four Canadian provinces.

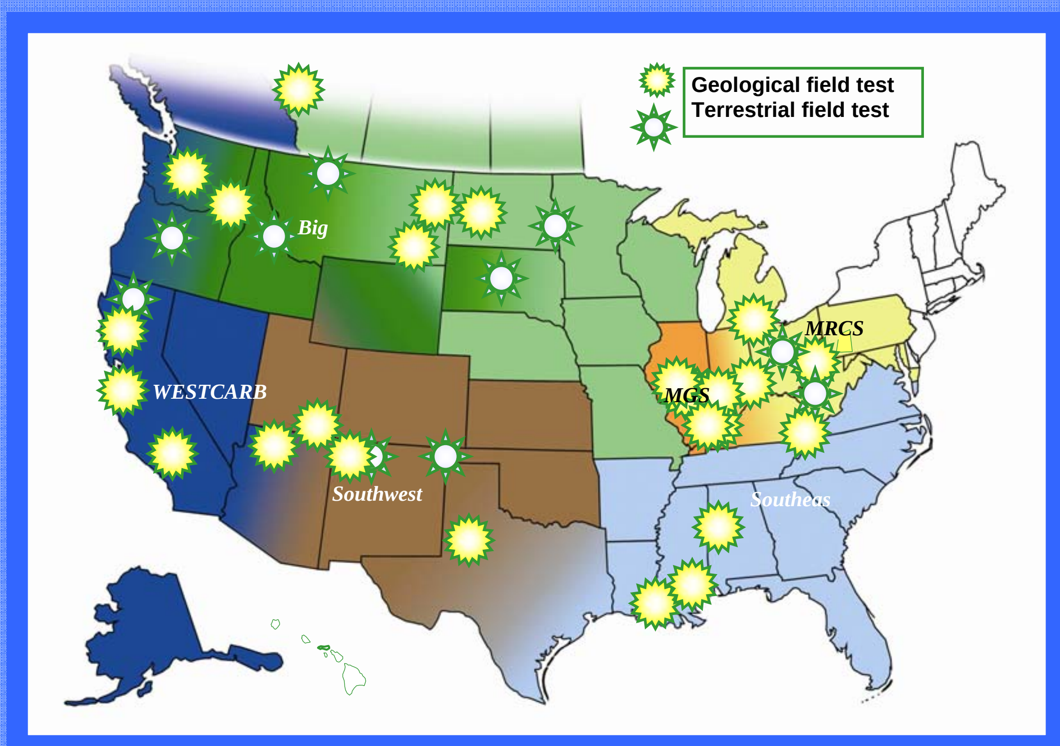
Partnership Name	Partnership Lead
Big Sky Carbon Sequestration Partnership	Montana State University
Midwest Geological Sequestration Consortium	University of Illinois, Illinois State Geological Survey
Midwest Regional Carbon Sequestration Partnership	Battelle Memorial Institute
Plains CO_2 Reduction Partnership	University of North Dakota, Energy & Environmental Research Center
Southeast Regional Carbon Sequestration Partnership	Southern States Energy Board
Southwest Regional Partnership on Carbon Sequestration	New Mexico Institute of Mining and Technology
West Coast Regional Carbon Sequestration Partnership	California Energy Commission

Figure 7-2: CO_2 Partnerships

The RCSPs' work was conceived by DOE and its partners in three phases. The first, the Characterization Phase, was conducted from September 2003 through June 2005. DOE awarded approximately $11.1 million to the RCSPs, with each group receiving up to $1.6 million over the two-year program period. The RCSPs conducted an analysis that described CO_2 sources, sinks and transport requirements; developed an outreach plan; conducted risk and environmental assessments; reviewed permitting and regulatory requirements; established measurement, monitoring and verification protocols; established accounting frameworks, including Section 1605(b) of the Energy Policy Act (EPACT) of 1992; identified the region's most promising capture and sequestration opportunities; and developed field validation plans. The second phase, known as the Validation Phase, is under way and will conclude by the fall of 2009. In this phase, DOE is providing $100 million to the RCSPs to further develop carbon sequestration technologies used to capture and permanently store greenhouse gases. A third Implementation Phase will follow to demonstrate large-scale CO_2 capture and storage technologies.

RCSP Process

- *Phase 1 – Characterization Phase through June 2005*
- *Phase 2 – Validation phase through 2009 will develop carbon sequestration technologies*
- *Phase 3 – Implementation phase will be a large scale demonstration of carbon dioxide capture and store technologies.*



Regional Carbon Sequestration Partnerships, Phase II Field Validation Sites
Source: U.S. Department of Energy/National Energy Technology Laboratory

Figure 7-3: Field Validation Sites

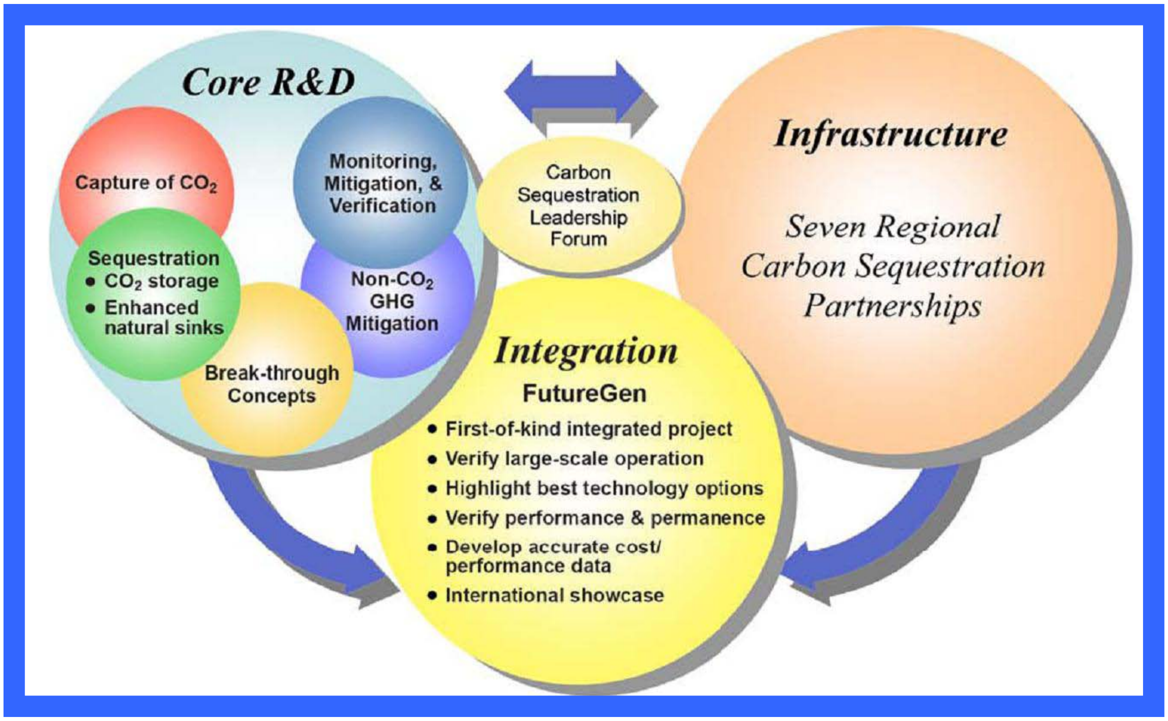


Figure 7-4: DOE Carbon Sequestration Program Structure [98]
Source: DOE

Clean Coal Technology Demonstration Programs

Since 1986, the Department of Energy has conducted large-scale demonstration projects under a series of programs beginning with the Clean Coal Technology (CCT) demonstration program in 1986, and followed by the Power Plant Improvement Initiative (PPII) and the current Clean Coal Power Initiative (CCPI). Information on past and current projects can be found at the NETL website[99]. All three programs are government/industry partnerships to demonstrate first-of-a-kind clean coal technologies at commercial or near-commercial scale. The DOE requires at least a 50 percent non-federal share of the project funds (historically, the non-federal cost-share as been about 65 percent). The CCPI was established in 2001 to implement the President's National Energy Policy recommendation to increase investment in clean coal technology, and Congress authorized for $2 billion in CCPI funding in the Energy Policy Act of 2005. These programs address the challenge of ensuring the reliability of the U.S electric supply while protecting the environment. The goal is to accelerate commercial deployment of advanced technologies to ensure that the U.S. has clean, reliable and affordable electricity. Some clean coal technology funds also have been used to support demonstration of the production of alternative fuels from coal.

Since the inception of the CCT program, the demonstration projects have included technologies that produce highly relevant efficiency increases and effective carbon management for coal-fueled power plants. Notably, the only two operating integrated gasification combined cycle (IGCC) units in the United States (Wabash and TECO) were funded by the CCT program. The CCPI program includes three more gasification-based projects (Mesaba, Orlando and Gilberton).

The CCPI program also includes two advanced fluidized bed combustion projects and an efficiency enhancement project for lignite-fueled boilers.

The FutureGen Project

On February 27, 2003, President Bush announced a $1 billion, 10-year demonstration project to create the world's first coal-based, zero-emissions electricity and hydrogen power plant. The FutureGen plant will establish the technical and economic feasibility of producing electricity and hydrogen from coal while capturing and storing the carbon dioxide generated.

In late 2005, eight coal-producing and coal-based electricity generating companies incorporated the FutureGen Industrial Alliance, Inc. (the Alliance), a non-profit corporation, to respond to the FutureGen Initiative.

The 12 companies now comprising the Alliance are among the largest coal-mining and coal-using companies in the world, with operations in Asia, Australia, Canada, Continental Europe, the People's Republic of China, South Africa, South America and the United States. Details concerning the Alliance, its members and the project can be found on the Alliance's website.[100]

The Alliance entered into a cooperative agreement with the DOE in December 2005 to conduct the FutureGen project and provide the private-sector cost share. Since then, the Alliance and DOE have been conducting the first phase of the project (Budget Period 0, in DOE parlance). Notable accomplishments to date include:

- A rigorous site selection process that resulted in identification of four candidate sites, two each in Texas and Illinois
- An Advanced Notice of Intent for an Environmental Impact Statement for the FutureGen project
- Identification and assessment of potential cutting-edge technology and readiness for inclusion for further evaluation
- Conceptual designs on several plant configurations and associated preliminary cost estimates
- Preliminary planning activities for permitting process
- Initial evaluation of the four candidate sites, including public outreach meetings in accordance with the National Environmental Policy Act

FutureGen Alliance Members

- *American Electric Power*
- *Anglo American LLC*
- *BHP Billiton*
- *China Huaneng Group*
- *CONSOL Energy Inc.*
- *E.ON U.S.*
- *Foundation Coal*
- *Peabody Energy, Inc.*
- *PPL Corporation*
- *Rio Tinto Energy America*
- *Southern Company*
- *Xstrata Coal*

In December 2006, the Alliance completed an Initial Conceptual Design Report, which will serve as the basis for agreement on plans for execution of the full project. The Alliance plans to select a site in late 2007, begin construction in early 2010 and be in commercial operation by 2012.

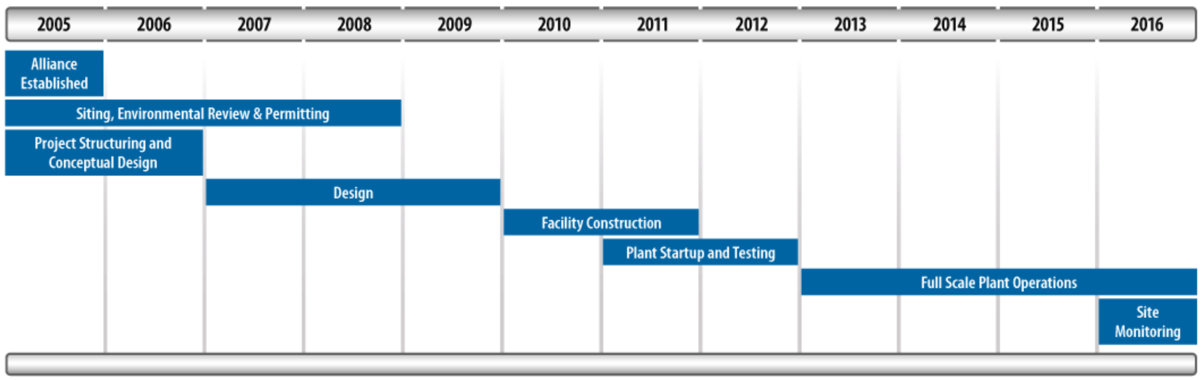


Figure 7-5: FutureGen Project Timeline[101]
Source: FutureGen Alliance

FutureGen will employ coal gasification technology to produce 275 MW equivalent gross electricity output. The large scale of the plant is driven by the need to adequately validate the engineering, economic and environmental viability of this particular embodiment of coal-based, zero emissions technology.

Power generation and hydrogen production will be integrated with the capture of CO_2 and its storage in deep, stable underground geologic formations. FutureGen will seek to sequester CO_2 at a rate of at least one million tons per year in order to adequately stress test a representative portion of a geologic formation. It will have the capacity to sequester 2.5 million tons per year. The plant also will meet stringent limits on all other environmental emissions associated with coal use. Thus, it will demonstrate the capability of technology to effectively eliminate environmental concerns associated with the use of coal.

The FutureGen design will address scaling and integration issues for coal-based, zero emissions energy plants. The plant will test and validate additional advanced technologies as they emerge from DOE and other RD&D programs that offer the promise of clean environmental performance at a reduced cost and increased reliability. Thus, FutureGen will have the flexibility to conduct full scale and slipstream tests of such scalable advanced technology over its entire operation.

Timetable

The FutureGen Alliance plans to select a site in late 2007, begin construction in early 2010 and be in commercial operation by 2012.

Goal

FutureGen will seek to sequester CO_2 at a rate of one million tons per year and meet stringent limits on other emissions. It hopes to demonstrate technologies that can virtually eliminate environmental concerns associated with the use of coal.

FutureGen will be a key step in creating a zero emission coal energy option which will allow countries to meet their growing energy needs.

Integration of concepts and components is the key to proving the technical and operational viability as well as gaining acceptance of the zero emission coal concept.

Technical Goals: The FutureGen goal is to design, construct and operate a 275 MWe commercial scale plant that can co-produce electricity and hydrogen fuel, while sequestering CO_2 at an annual rate of up to 2.5 million metric tonnes. This plant will:

- Initially sequester at least 90 percent of CO_2, and eventually up to 100 percent
- Prove the effectiveness, safety and permanence of large scale CO_2 sequestration through validating the technology under real world conditions
- Establish technology standards and protocols for CO_2 measuring, mitigation and verification
- Lead to projects for commercialization in other projects by 2020

Technological Options: In its role as a "living laboratory," FutureGen is designed to test, either in the basic configuration or through associated on-site testing, a variety of emerging technologies, such as

- O_2 membranes to replace cryogenic separation
- Advanced transport reactor
- H_2 membranes, CO_2 separation or advanced Selexol®
- Raw gas shift reactor
- Ultra low nitrogen oxide (NO_X) hydrogen turbine
- Design of fuel cell hybrid system at $400/kW
- Challenging first-of-a-kind system integration
- Smart dynamic plant controls and CO_2 management system

International FutureGen Participation: Besides private sector participation through Alliance membership, the DOE is offering international governments the opportunity to participate through membership in a Government Steering Committee, a group of officials from the U.S. and participating foreign governments. To date, the governments of India and South Korea have indicated they intend to join.

Advanced Ultra-supercritical Boiler Project

The importance of advanced materials development to the future of electric generation in either pulverized coal (PC) or IGCC applications has been stressed a number of times throughout this report. A formal public-private RD&D consortium has been established to identify, evaluate and qualify materials technology for construction of coal-fired boilers and turbines with advanced steam cycles capable of operating at much higher efficiencies than current state-of-the-art facilities and capable of burning high-sulfur Ohio coal.

This $26 million project, entitled "Evaluating Materials Technology for Ultra-supercritical Coal-Fired Plants," is funded by the DOE through NETL and co-funded by the Ohio Air Quality Development Authority's Ohio Coal Development Office (OCDO). Overall program management is the responsibility of Energy Industries of Ohio (EIO), a 501.c.3 non-profit research and development organization with overall technical coordination and management provided by EPRI. Private sector consortium members include domestic boiler manufacturers

Alstom Power, Riley Power, Babcock & Wilcox, and Foster Wheeler. Oak Ridge National Laboratory also participates in the consortium, adding its substantial experience in materials research and development to this effort.

Currently, material technology permits construction of 1112°F/4000 psi (600°C/28MPa) PC power plants. Commercial availability of 1150°F (620°C) plants is estimated to be only one to two years away, at least for units burning low sulfur coals, while a 1200°F (650°C) plant may be only five years away. Based on a review of worldwide materials development activities, the U.S. program has defined the RD&D necessary to build upon these capabilities.

Phase I of the U.S. program includes work to identify, fabricate and test advanced materials and coatings with mechanical properties, oxidation resistance and fireside corrosion resistance suitable for cost-competitive boiler operation at steam temperatures of up to 1400°F (760°C) at 5500 psi (38.5 MPa). These ultra-supercritical (USC) plants are anticipated to become a reality around year 2015. Such a plant will result in 45-47 percent higher hearing value (HHV) efficiency with reduction of all effluents by more than 30 percent. In addition, exploratory attention is being given to the materials issues that affect boiler design and operation at temperatures as high as 1600°F (870°C).

Phase II of the project involves optimizing the designs using the knowledge gained in Phase I and conducting further field evaluations. The studies also will be extended to defining the conditions prevailing in Oxy fuel-fired boilers and their effects on material degradation. It is believed that Oxy fuel combustion in USC boilers may represent the ideal combination for substantial reduction of pollutants.

In a separate effort under Phase II, steam turbine materials are under evaluation by a second consortium which includes private industry members Alstom Power, General Electric and Siemens. Again, this effort is managed by EIO and EPRI and funded by DOE and OCDO. Principal activities at present include identification of materials suitable for both welded and non welded rotor configurations, blading and castings and development of coatings resistant to oxidation and solid particle erosion. [102]

Electric Power Research Institute (EPRI)

EPRI's Research Program on CO_2 Capture and Storage

EPRI's research program in CO_2 CCS aims to achieve agreed-upon environmental goals through development of cost-effective reduction options, efficient design and implementation of climate policies that allow their use, and effective strategic responses by companies. These goals will be met by:

- Stimulating development of new and improved direct CO_2 CCS options
- Providing economic, financial, legal and environmental analysis of CCS options to develop policies that are cost-effective and environmentally effective
- Helping companies design business strategies that effectively account for potential greenhouse gas (GHG) emission limitations

To foster creation and development of commercially mature carbon sequestration technologies, EPRI performs technical and economic assessments of leading technologies and makes focused investments in development and demonstration of promising new technologies:

- Chilled ammonia process (Nextant)
- Potassium carbonate process (RTI's)
- Chilled ammonia process demonstration on a 5-MW slipstream pilot. (with Alstom)
- Other processes using slipstream pilots

CoalFleet for Tomorrow – Future Coal Generation Options (CoalFleet)

CoalFleet is EPRI's global industry-led collaborative program to accelerate the commercial deployment of advanced coal power systems, including IGCC, USC PC, and supercritical fluidized bed combustion (SC FBC) by creating "consensus-based" plant design guidelines. The guidelines can move the industry toward standardized plant designs with lower costs, higher reliability and near-zero emissions, while assuring incorporation of technical advances and the lessons learned from operating experiences worldwide. CoalFleet projects also address lowering the cost and energy penalty for CO_2 capture processes, a key issue for future coal power systems. The ultimate goal is to support development of a self-sustaining, competitive commercial infrastructure for advanced coal power plants.

The CoalFleet Program consists of four "Project Sets:"

Engineering and Economic Evaluations and Market Assessments of Advanced Coal Generation Options provide data and comparative assessments that support site-specific feasibility studies for all advanced coal technologies. It includes plant operations summaries, market and risk assessments and engineering assessments of the expected cost, performance, fuel flexibility and reliability for advanced coal-based power plants with and without CO_2 capture capability.

The Gasification-Based Power Plant Development and Deployment Support (IGCC) project provides "User Design Basis Specifications" for IGCC plants based on feasibility, preliminary engineering and front-end engineering design studies by CoalFleet participants, along with more detailed "pre-design" and "generic design" specifications. These specifications will be crucial to developing standardized IGCC plant designs that are accepted by industry, regulators and financial analysts and that reduce capital costs, improve reliability and achieve near-zero emissions. This project set also includes engineering/economic evaluations of advanced IGCC designs and configurations, including co-production options for hydrogen and Fischer-Tropsch (coal to liquids) diesel.

Combustion-Based Power Plant Development and Deployment Support (PC and CFBC) is creating user design basis specifications for USC PC and SC circulating fluidized bed combustion (CFBC) plants in a manner similar to that described above for IGCC plants. A companion goal is to create an industry plan for addressing future CO_2 capture requirements. This project set also addresses longer-term efficiency goals for PC and FBC plants through advanced design and materials development work that will enable plant operation at steam temperatures up to 1400°F (760°C). This project set also includes evaluation of improved options for CO_2 capture (both back-end and "integrated") such as Oxy fuel and chemical looping.

The Power Systems Development Facility (PSDF) for Low-Rank Fuels project set provides access to the RD&D at the Power Systems Development Facility (PSDF) pilot "transport gasifier" in Wilsonville, Alabama, which conducts tests with low-rank fuels, improved coal feeding and solids removal equipment, alternative syngas clean-up processes, and hydrogen co-production and hybrid power generation. The PSDF program includes research on oxygen membranes, hydrogen-separation membranes, a syngas-fed planar solid oxide fuel cell, technologies and sorbents for near-zero emissions, and processes to separate CO_2 from both syngas and flue gas.

Coal Utilization Research Council (CURC)

The 55-member CURC is an ad-hoc group of electric utilities, coal producers, equipment suppliers, state government agencies and universities working to promote research, development, demonstration and deployment of clean coal technologies

A Clean Coal Technology Roadmap, originally released by CURC, DOE and EPRI in 2001 and updated by CURC and EPRI in 2006[103], identifies RD&D priorities that could lead to the coal-based technologies that will be cost-effective, highly efficient and achieve near zero emissions, including the capture and sequestration of CO_2. CURC estimates that the cost to achieve its goals is approximately $11 billion by 2025 in combined federal and other than federal spending

The CURC-EPRI Roadmap includes a technology development program for carbon management, defined as the capture and sequestration of CO_2. The major finding of the CURC-EPRI Roadmap is that by 2025, combustion- and gasification-based power generation options can be available commercially – with the ability to capture and sequester CO_2 – at a cost of electricity competitive to the cost of new power generation (without CO_2 capture) today.

> **Cost Projection**
>
> *The major finding of the CURC-EPRI Roadmap is that by 2025, combustion- and gasification-based power generation options can be available commercially – with the ability to capture and sequester CO_2 – at a cost of electricity competitive to the cost of new power generation (without CO_2 capture) today.*

The Roadmap targets two approaches to carbon management:

(1) higher efficiency to reduce emissions of CO_2, and
(2) capture and geologic sequestration of CO_2.

The goal is to have, by 2025, new combustion- and gasification-based systems operating with carbon capture with thermal efficiency between 39 percent and 46 percent and a cost of electricity between $37 and $39/MWh. By 2025, the incremental cost to transport and sequester the CO_2 is projected to be between $2 and $7/MWh, provided the following technology steps are taken:

- By 2010, support all DOE Regional Carbon Sequestration Partnerships activities to conduct small-scale field tests to store CO_2 in geological and terrestrial systems and develop tools and protocols necessary for permitting commercial sequestration operations;

- By 2015, conduct at least one large-scale commercial demonstration of CO_2 storage in each type of geological formation:
  - oil or gas reservoirs
  - coal seams
  - saline formations
- By 2015 develop the predictive tools and monitoring protocols to allow permitting of commercial CO_2 storage facilities.

CURC believes, however, that current funding for coal RD&D is barely adequate and funding for demonstrations is totally inadequate. The FY2007 DOE budget request provided a reasonable level of funding (if spent appropriately) for coal RD&D (including the FutureGen project), but only $5 million for clean coal demonstrations (the Clean Coal Power Initiative). The President's 2007 budget request for the coal RD&D CCPI programs does not reflect the levels authorized in EPACT, which are necessary to achieve Roadmap goals.

Other Domestic Activities

While a number of U.S. state governments have enacted or are considering legislation affecting greenhouse gas emissions, others are also taking action to facilitate the development and deployment of technology to help manage CO_2 emissions from coal-fueled power plants. These include Ohio, which has a longstanding involvement in the development and deployment of coal use technology through the Ohio Coal Development Office[104], and Illinois, which funds coal RD&D through the Illinois Clean Coal Institute[105]. As discussed below, private industry, government organizations and universities in 41 states and four Canadian provinces are members of the seven DOE Regional Carbon Sequestration Partnerships.

Texas has taken or is considering a number of steps to facilitate the introduction of zero-emission coal technology, including legislation passed that places liability for CO_2 long-term storage on the state, a pilot project by DOE to store 16,000 tons of CO_2 in saline formations, tests on converting CO_2 and other emissions from existing plants into commercial applications and possible legislation to offer tax incentives and expedited permitting to FutureGen-like facilities. Pennsylvania enacted an Advance Energy Portfolio Standard that includes IGCC as a qualifying source.

International Programs and Projects

Technology for carbon management from power plants and other sources is a topic of intense international interest. Several international organizations are highlighted below, and many national programs also exist.

Carbon Sequestration Leadership Forum

The U.S. government recognizes that a technological approach will be necessary to reduce greenhouse gas emissions from coal use. The Carbon Sequestration Leadership Forum (CSLF) was formed to implement this policy through cooperative international action. The multinational CSLF initiative, announced in February 2003, is led by the U.S. DOE and State Department. CSLF member countries and organizations are major producers or users of coal, oil or natural gas. Members include Australia, Brazil, Canada, China, Columbia, European Commission, France, Germany, India, Italy, Japan, Mexico, Norway, Russian Federation, South Africa, United Kingdom and United States. The CSLF is designed to provide a mechanism to foster the rapid development and deployment of technologies that can capture and store much of the CO_2 created by fossil fuel use.

In September 2004, ministers of the CSLF countries, meeting in Melbourne, endorsed 10 collaborative projects undertaken by member countries. These international projects, which are jointly funded by the sponsoring countries, demonstrate considerable technical progress in carbon sequestration. In September 2005, seven additional projects were endorsed by the CSLF, including four in India and China.[106]

The CSLF consists of a policy group and a technical group. Since its inception, stakeholder involvement has been a key objective of the CSLF. In particular, the CSLF has involved stakeholders in prominent places at both of the ministerial and other meetings during the summer of 2004. The CSLF has made a special effort to engage the environmental community, particularly the Natural Resources Defense Council, in its deliberations. In addition, the U.S. Energy Association holds stakeholder meetings to ensure stakeholder involvement.

The CSLF believes much of the need for carbon capture and storage technologies will be in developing countries, as requirements for energy in those countries increase to provide for economic development and political stability. In addition to the projects under way, CSLF anticipates that China, Mexico and other CSLF countries that do not yet have active sequestration projects will soon nominate joint projects for CSLF approval. The CSLF expresses a particular interest in RD&D that addresses ways to:

- Lower the costs of carbon capture technologies
- Identify the most promising reservoir types for CO_2 storage, develop reservoir selection criteria, and refine estimates of worldwide storage capacity
- Identify specific CO_2 storage measurement, monitoring and verification requirements and assess specific options so these technologies can be commercially available by 2012

Asia-Pacific Partnership on Clean Development and Climate

The Asia-Pacific Partnership on Clean Development and Climate[107], also known as AP6 or APP, is an agreement initiated in January 2006 among Australia, India, Japan, the People's Republic of China, South Korea and the United States. Foreign, environment and energy ministers from the member countries agreed to cooperate on development and transfer of technology that enables reduction of greenhouse gas emissions. Ministers agreed to a Charter, Communiqué and Work Plan that "outline a ground-breaking new model of private-public taskforces to address climate change, energy security and air pollution."

The ministerial meeting established eight government and business taskforces (see box). Significantly, the six partner countries represent about half of the world's economy, population and energy use, and they produce about 65 percent of the world's coal, 48 percent of the world's steel, 37 percent of world's aluminum and 61 percent of the world's cement.

Through meetings and outreach activities during the spring and summer of 2006, the eight task forces formulated action plans, which were formally endorsed by the AP6 Policy and Implementation Committee on October 12, 2006. The action plans of two task forces are particularly relevant to the current National Coal Council (NCC) study.

APP Taskforce Focus Areas

- *Cleaner fossil energy*
- *Renewable energy and distributed generation*
- *Power generation and transmission*
- *Steel*
- *Aluminum*
- *Cement*
- *Coal mining*
- *Buildings and appliances*

The Cleaner Fossil Energy Task Force identified five major themes for its work:

- *CO_2 storage*: to develop commercial storage sites by 2015
- *Post-combustion capture*, *Oxy fuel combustion and other advanced technologies*: to achieve commercial deployment of large-scale Oxy-fired and PCC technologies by 2015, and achieve commercial deployment of other advanced coal technologies, such as ultra clean coal, by 2015
- *Coal gasification*: to achieve a range of objectives including the commercial deployment of large-scale IGCC technology by 2015, CO_2 capture from polygeneration plants by 2015, and commence operation of large-scale demonstration of IGCC with carbon capture and storage by 2015
- *Energy market access for gas*: to improve environmental performance while supporting energy security by addressing potential barriers to liquid natural gas (LNG) market efficiency and growth
- *Gas handling infrastructure improvements*: to realize the economic and environmental benefits of reducing the loss of gas during its handling and transportation

The Power Generation and Transmission Task Force identified 13 projects (described in that Task Force's action plan[108]) across four themes:

- *Information sharing*: facilitating information sharing on key power generation and transmission issues among AP6 partner countries to assist the task force in identifying priority issues and to guide future task force projects
- *Best practices for power generation*: building a knowledge base to increase power generation efficiency, reduce emissions, improve operation and maintenance, and facilitate life extension and/or retrofits; facilitate demonstration and deployment of best practices and technology through on-site visits, reviews and technical cooperation initiatives
- *Best practices for transmission and distribution*: build a knowledge base to improve transmission and distribution by reducing system losses, enhancing connection standards and equipment, system upgrades, and improved grid planning and operation

- *Best practices for demand side management*, including techniques such as smart metering and user energy efficiency.

International Energy Agency Greenhouse Gas Programme

The International Energy Agency (IEA)[109] Greenhouse Gas R&D Programme (IEA GHG)[110], established in 1991, is an international collaborative research effort, studying technologies to reduce greenhouse gas emissions. The IEA GHG is supported by 16 member countries, the European Commission and 10 multi-national sponsors. It has three main activities:

- Evaluation of technologies to reduce greenhouse gas emissions
- Promotion and dissemination of results and data from its evaluation studies through technical reports, general publications and conferences
- Facilitating practical RD&D

The program covers all the main anthropogenic greenhouse gases (CO_2, methane, nitrous oxide and high global warming potential gases), but primarily focuses on ways to reduce emissions of CO_2. A separate website[111] provides information on over 100 RD&D projects associated with the IEA GHG.

The technical reports and conferences sponsored by IEA GHG are particularly notable, with eight of the latter being held since 1997. The most recent[112] in June 2006 attracted 950 attendees and several hundred papers (available online), principally on the topic of carbon capture and storage. The provide information on national and international programs in the United States, Australia, Canada, Asia and throughout Europe.

Other International Carbon Management Technology Programs

CASTOR[113]**,** "CO_2 from Capture to Storage," is a European initiative of 30 partners (industries, research institutes and universities) from 11 European countries, partially funded by the European Commission. The overall goal of CASTOR is to develop and validate innovative technologies to capture CO_2 and store CO_2 in a reliable and safe way. Key targets of CASTOR are a major reduction in post-combustion capture costs (by about 50 percent), to advance general acceptance of the overall concept in terms of storage performance (capacity, CO_2 residence time), storage security and environmental acceptability, and to start the development of an integrated strategy connecting capture, transport and storage options for Europe. The CASTOR budget is largely directed at post-combustion CO_2 capture.

ENCAP [114] is a project to develop new pre-combustion CO_2 capture technologies and processes for power generation, with at least a 90 percent CO_2 capture rate and a 50 percent reduction in the cost of capture compared to present. The project has 33 participants including six large European fossil fuel end users, 11 leading technology providers and 16 ranked RD&D providers from 11 European countries, funded by the European Commission. ENCAP is intended to develop new design projects by 2008-2010, leading to a large demonstration plant with the potential for wide commercial deployment by 2020. Current project areas include Process and

Power Systems, Pre-Combustion Decarbonization Technologies, Oxy Fuel Boiler Technologies, Chemical Looping Combustion, High-Temperature Oxygen Generation for Power Cycles, and Novel Pre-Combustion Capture Concepts.

European Technology Platform on Zero Emission Fossil Fuel Power Plants (ETP ZEP) [115] is a consortium formed by the European Commission and the European energy industry, research community and non-governmental organizations to develop and deploy new competitive options for zero emission fossil fuel power plants within the next 15 years.

The Cooperative Research Centre for Greenhouse Gas Technologies [116] **(CO_2CRC)** is an Australia collaborative research organization begun in 2004 that focuses on CO_2 capture and geological storage. The CO_2CRC, with 22 members, obtains funding from the Australian government and private industry for research conducted principally at Australian universities and the state research laboratory, the Commonwealth Scientific & Industrial Research Organisation (CSIRO). Among highlighted accomplishments is the GEODISC program, which established that the geological features of Australia are suitable for geological storage of carbon dioxide. CO_2CRC plans to conduct geological storage demonstration.

CO_2 Capture Project [117] is a joint project comprising eight of the world's largest petroleum companies[118] in conjunction with the U.S. DOE and the European Commission. Their efforts are focused on reducing the cost of CO_2 capture from combustion sources such as turbines, heaters and boilers and developing methods for geologic storage of CO_2. The website indicates that a first phase was conducted from 2000 through 2004, and a second phase begun in 2005 is scheduled to run through 2007.

Other Large-Scale Coal-based Carbon Capture and Storage Projects

In addition to the FutureGen project in the United States, a number of other large carbon capture and storage projects are in various states of development worldwide. The figure below[119] depicts the status of several more prominent projects that have been announced. Most are still in the "study" phase, but some have moved on to engineering. The key common feature of these projects is that they integrate carbon capture and storage with electricity generation in commercial scale facilities. Operations are projected begin as early as 2007, but most are projected to begin in the 2010-2012 time frame, and continue to the middle of the next decade. This demonstrates some consensus on understanding the relatively long time necessary to bring integrated electricity generation/CCS technologies to commercial readiness. If these first-of-a-kind efforts are completed, it will take perhaps another decade to bring the technologies to broad commercial deployment.

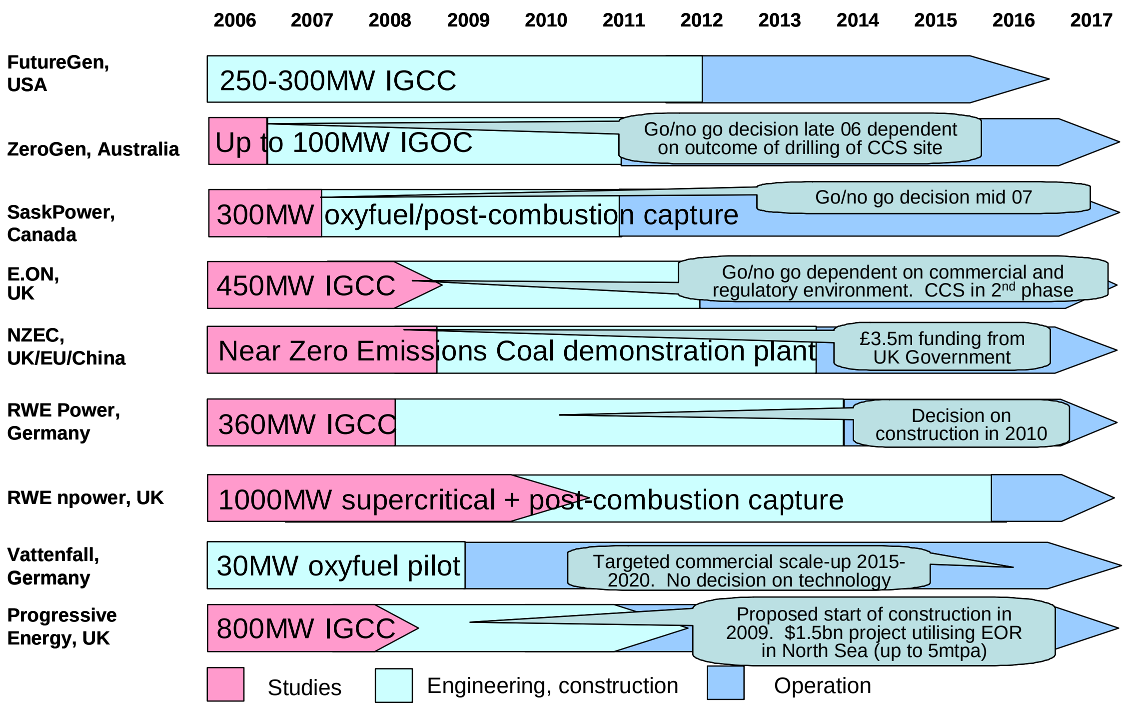


Figure 7-6: Carbon Capture and Storage Projects
Source: Samantha Hoe-Richardson

CONCLUSIONS

- While funding for CO_2 capture and storage research has accelerated in recent years, it is insufficient to advance the commercialization of the technology at an acceptable pace, particularly for large-scale stand-alone and integrated CCS demonstrations and for deployment of the technology.
- Public/private partnerships work – the U.S. needs to accelerate these efforts.
- The DOE-NETL Regional Carbon Sequestration Partnerships are already in progress and advancing knowledge surrounding carbon sequestration technology.

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[100] http://www.futuregenalliance.org
[101] http://www.futuregenalliance.org/about/timeline.stm
[102] Additional information on the Advanced Ultra-supercritical Boiler Project, contact Vis Viswanathan, rviswana@epri.com, or Bob Purgert, purgert@energyinohio.org.
[103] http://www.coal.org/content/roadmap.htm
[104] http://www.ohioairquality.org/ocdo/coal_main.asp
[105] http://www.icci.org/
[106] Information on the CSLF and the projects currently under way can be found at the following web address: http://www.cslforum.org/projects.htm
[107] http://www.asiapacificpartnership.org/
[108] http://www.asiapacificpartnership.org/PowerGeneration-TransmissionTF.htm
[109] The IEA is an autonomous body within the framework of the Organisation for Economic Cooperation and Development (OECD). It carries out a comprehensive program of energy coordination among 26 member countries. The European Commission also takes part in the work of the IEA., see http://www.iea.org
[110] http://www.ieagreen.org.uk/index.html
[111] http://www.co2captureandstorage.info/co2db.php4
[112] https://events.adm.ntnu.no/ei/rs.esp?id=24&scriptid=SPPP1
[113] http://www.co2castor.com/QuickPlace/castor/Main.nsf/
[114] http://www.encapco2.org/
[115] http://www.zero-emissionplatform.eu/website/
[116] http://www.co2crc.com.au/
[117] http://www.co2captureproject.org/index.htm
[118] Current members are BP, Chevron Texaco, ENI, Norsk Hydro, Suncor, Shell, ConocoPhillips, and Petrobras.
[119] “FutureGen - A ‘first-of-a-kind’ near-zero emission coal-fueled power plant,” Samantha Hoe-Richardson, COALTRANS, London, September 2006.

SECTION EIGHT

Energy Policy Act of 2005 – Key Coal Provisions

FINDINGS

The Energy Policy Act of 2005 (EPACT) is very supportive of expanded coal use in the United States through focused environmental initiatives, funding for research and development, important demonstration projects such as the Clean Coal Power Initiative, and incentives for development and commercialization of new technologies. The bill authorized about $6.1 billion for specific coal-related projects and $2.9 billion in tax incentives. It includes a climate change title that essentially codifies the voluntary, technology-based approach to the climate change issue.

COAL PROGRAMS, PROJECTS AND ISSUES ADDRESSED BY EPACT 2005

The Clean Coal Power Initiative

A nine-year, $1.8 billion program ($200 million annually from 2006 to 2014) to demonstrate advanced coal technologies. At least 70 percent of the funds must be used to demonstrate coal gasification technologies, and up to 30 percent can be used for advanced pulverized coal technologies. To be eligible for funding, the technologies must meet increasingly stringent emissions reduction and efficiency criteria. Federal funding can be up to 50 percent of the total at the discretion of the Secretary of Energy. Federal funds need not be repaid.

Basic Coal Research and Development

A three-year, $1.137 billion research, development and demonstration (RD&D) program beginning in 2007. Funds are dedicated specifically to coal and coal-related research and represent just over 60 percent of the total funds authorized for fossil energy research.

Carbon Capture and Sequestration Research

A 10-year RD&D program to develop carbon capture technologies for existing and new coal-based electric generating units. The program is funded initially by a three-year $90 million authorization beginning in 2006.

Coal Mining Research

A three-year, $75 million program focusing on coal mining RD&D, with specific attention to projects and priorities recommended by the Industry of the Future program.

Clean Air Coal Program

A new, $3 billion Clean Air Coal Program in two parts:

- Part One, a $500 million, five-year program beginning in 2007, will help existing plants install advanced pollution control technologies to help them meet the new sulfur dioxide, nitrogen oxide and mercury reduction requirements being imposed by the Environmental Protection Agency's Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), or possibly by new emissions control legislation.

- Part Two, a $2.5 billion, seven-year program, is intended to help electric generators install advanced clean coal technologies either to repower or replace existing generating capacity or as new capacity. Technologies eligible for this program include integrated gasification combined cycle (IGCC) and supercritical boiler technologies. Priority is given to technologies that are demonstrated, but not yet commercially viable.

Federal assistance is in the form of cost sharing (not to exceed 50 percent of the project's cost) or in the form of grants or loan guarantees.

Climate Change

A voluntary and technology-based climate program to reduce greenhouse gas (GHG) emissions intensity and help meet the current administration's goal of reducing GHG emission intensity by 18 percent by 2012, compared to 2000 levels. The law supports a strong voluntary and technology-based program to address climate change on an international basis. The climate title essentially codifies the voluntary, technology-based approach to the climate change issue and calls for development of a national strategy to identify and promote commercialization and widespread use of technologies to reduce GHG emissions intensity. The title also calls for development and implementation of a strategy to deploy those technologies in developing countries in part by identifying and removing barriers to the export of U.S. technology.

Work Force Studies

Two studies are designed to address labor shortages in the energy industry. The first directs the Secretary of Energy and Secretary of Labor to analyze the trends in availability of skilled technical personnel to support energy technology industries (including coal mining) and to monitor and report on these trends on an ongoing basis. The second will be a two-year study by the National Academy of Sciences on the short- and long-term availability of skilled workers to meet the energy and mineral security requirements of the United States.

EPACT 2005 Significant Coal-Related Tax Incentives

EPACT 2005 included a tax package of about $2.9 billion to stimulate additional use of new pollution control and clean coal technologies. This represents 25 percent of the reported $11.5 billion energy tax bill (after offsets) that was incorporated into the law.

Clean Coal Tax Incentives or the Credit for Investment in Clean Coal Facilities.

- A 20 percent investment tax credit for qualified investment in IGCC technologies, with an $800 million cap on the tax credits (as opposed to a megawatt cap).

- A 15 percent investment tax credit for qualified investment in advanced coal-based generation technologies, with a $500 million cap.
- Funds may be reallocated between the two programs if all dollars in one are not used. The Secretary of the Treasury determines certification for the projects.

Tax incentives for industrial gasification projects

- A 20-year, 20 percent investment tax credit, capped at $350 million, for qualified investment in gasification projects at industrial facilities. The tax credit is open to domestic gasification applications related to chemicals, fertilizers, glass, steel and other industrial processes and can include biomass or petroleum coke.

Accelerated depreciation for pollution control equipment at post-1975 coal plants

- The depreciation schedule for pollution control equipment is changed from the current 15 years to seven years for coal plants and is important as existing units make investments to comply with CAIR and CAMR. The total effect of the provision is $1.147 billion.

Section 29 credit for coke or coke oven gas at coke plants placed in service before January 1, 1993 or between June 30, 1998 and January 1, 2010.

- The credit applies only to coke or coke oven gas produced after January 1, 2006. This effect of the provision is $101 million.

CONCLUSIONS

- Given the early stage of development of technologies for carbon capture, compression, delivery, storage and monitoring, as well as the known track record needed to bring such technologies to maturity in the market, the National Coal Council recommends that the Department of Energy (DOE) continue to support the many programs discussed throughout this report. As technologies mature, it will be even more important for DOE to support deployment of new technologies using all the tools at its disposal, such as financial incentives and favorable tax policies.

- Also, because limited data exist for IGCC units operating on low rank coals, the EPACT of 2005 encouraged increased investment in RD&D of IGCC plants using these coals to provide more accurate data on costs and performance. Given the growing importance of lower rank coals in U.S. electricity generation, this research should be continued for a range of gasification technologies, including slurry and dry feed gasifiers.

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APPENDICES

1. **Description of The National Coal Council**
2. **The National Coal Council Member Roster**
3. **Coal Policy Committee**
4. **2007 Study Work Group**
5. **Acknowledgements**
6. **Abbreviations**

APPENDIX 1

Description of The National Coal Council

In the fall of 1984, The National Coal Council was chartered and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which could, in turn, lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

Members of The National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a Chair and Vice-Chair who are elected by the Council. The Council is supported entirely by voluntary contributions from its members. To wit, it receives no funds whatsoever from the Federal Government. In reality, by conducting studies at no cost, which might otherwise have to be done by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry nor the views or any one particular part of the country. It is instead to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by The National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the start-up of the Council.

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Appendix 6

Abbreviations

AC	Ammonium carbonate
AMP	2 amino-2-methyl-1-propanol
AGR	Acid gas removal
APP	Asia Pacific Partnership on Clean Development and Climate
ASU	Air separation unit
Bcf	Billion cubic feet
Btu	British thermal unit
B&W	Babcock & Wilcox
BOP	Balance of plant
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Ca/S	Calcium-to-sulfur
CCPI	Clean Coal Power Initiative
CCS	Carbon capture and storage
CCT	Clean Coal Technology
CEPCI	Chemical Engineering Plant Cost Index
CFB	Circulating fluidized bed
CFBC	Circulating fluidized bed combustion
CMU	Carnegie Mellon University
CO_2	Carbon dioxide
CO_2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
COE	Cost of electricity
COS	Carbonyl Sulfide
CSLF	Carbon Sequestration Leadership Forum
CT	Combustion turbine
CTG	Combustion turbine generator
CTI	Cansolv Technologies Inc.
CTL	Coal to liquids
CTP	Coal to products
CURC	Coal Utilization Research Council
DCL	Direct coal liquefaction
DEA	Di-ethanol amine
DME	Di-methyl ether
DMEA	Methyl di-ethanol amine
DOE	Department of Energy
ECO®	Electro-Catalytic Oxidation (PowerSpan trademark)
ECO_2™	A scrubbing process that uses an ammonia-based solution (not an amine) to capture CO_2 from flue gas (PowerSpan trademark)
EIA	Energy Information Administration
EIO	Energy Industries of Ohio
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPRI	Electric Power Research Institute
EU	European Union
EC	European Commission
FBC	Fluidized bed combustion
FGD	Flue gas desulfurization
FT	Fischer-Tropsch
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas to liquids
GW	Gigawatts = 1000 megawatts or 1 million kilowatts
H_2	Hydrogen
H_2S	Hydrogen sulfide
H/C	Hydrogen/carbon
HON	Hydrogen cyanide
HHV	Higher heating value, a standard for measuring efficiency
HRSG	Heat recovery steam generator

IEA	International Energy Agency
ICDR	Initial Conceptual Design Report
ICL	Indirect coal liquefaction
IECM	Integrated Environmental Control Model
IEO	International Energy Outlook
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
IPCC	Intergovernmental Panel for Climate Change
ISO	International Organization for Standardization
KW	Kilowatt
Kwh	Kilowatt-hour
LCOE	Levelized cost of electricity
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MAC	Main air compressor
MDEA	Methyl di-ethanol amine
MEA	Monoethanol amine
MMV	Measurement, monitoring and verification
MTBE	Methyl tertiary-butyl ether
MTG	Methanol-to-gasoline
NCC	National Coal Council
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGO	Non Governmental organization
NH_3	Ammonia
NSR	New Source Review
NO_X	Nitrogen oxide
OCDO	Ohio Coal Development Office
OECD	Organisation for Economic Cooperation & Development
PC	Pulverized coal
PCC	Post combustion capture
PPII	Power Plant Improvement Initiative
PRB	Powder River Basin
PSDF	Power Systems Development Facility
Psi	Pounds per square inch
RCSPs	Regional Carbon Sequestration Partnerships
RD&D	Research, Development and Demonstration
SC	Supercritical
SCPC	Supercritical pulverized coal
SECARB	Southeast Regional Carbon Sequestration Partnership
SH/RH	Superheater/reheater
SCR	Selective catalytic reactor
SMR	Steam methane reforming
SNCR	Selective non-catalytic reduction
SNG	Synthesis natural gas
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SOC	Soil organic carbon
SO_X	Sulfur oxide
SubC	Subcritical
SwRI	Southwest Research Institute
TCR	Total capital requirement
TEA	Tert-ethanol amine
TPC	Total project cost
UCC	Ultra clean coal
USC	Ultra-supercritical
USC DRH	Ultra-supercritical double reheat
WEO	World Energy Outlook