THE NATIONAL COAL COUNCIL

LOW-CARBON COAL: MEETING U.S. ENERGY, EMPLOYMENT AND CO_2 EMISSION GOALS WITH 21[ST] CENTURY TECHNOLOGIES

December 2009

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

THE NATIONAL COAL COUNCIL

In the fall of 1984, The National Coal Council (NCC) was chartered and in April 1985, the NCC 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 and, in turn, lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The NCC is chartered by the U.S. Secretary of Energy under the Federal Advisory Committee Act. The purpose of the NCC 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 NCC are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The NCC is headed by a Chair and Vice-Chair who are elected by the NCC members. The NCC is supported entirely by voluntary contributions from its members. It receives no funds whatsoever from the Federal Government. By conducting studies at no cost, which might otherwise have to be done by the Department, it saves money for the government.

The NCC does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The NCC 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 a broad, objective advisory group with an approach that is national in scope.

Matters which the Secretary of Energy would like to have considered by the NCC 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 NCC 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 NCC.

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Prepared for

The U.S. Department of Energy

THE NATIONAL COAL COUNCIL
DECEMBER, 2009

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Terminology, Abbreviations, Acronyms and Initialisms

ACI .... activated carbon injection
ARRA .... American Recovery and Reinvestment Act of 2009
ASU .... air separation unit, an oxygen/nitrogen plant
Atm .... atmosphere

BACT .... Best Available Control Technology
BLM .... Bureau of Land Management
BTCC .... Babcock-Thermo Carbon Capture
Btu .... British thermal unit

CA .... carbonic anhydrase
CAA .... Clean Air Act
CCPI .... Clean Coal Power Initiative of the U.S. DOE
CCS .... CO_2 capture and storage (or sequestration)
CERCLA .... Comprehensive Environmental Response, Compensation and Liability Act
CFB .... circulating fluidized bed
CFR .... Code of Federal Regulations
CMAP .... Carbonate Mineralization by Aqueous Precipitation (Calera Corp.)
CO .... carbon monoxide
CO_2 .... carbon dioxide
COE .... cost of electricity
CTL .... coal to liquids
CURC .... Coal Utilization Research Council

DOE .... U.S. Department of Energy
DOT .... U.S. Department of Transportation
DRB .... demonstrated reserve base

ECBM .... enhanced coalbed methane
ECO_2® .... CO_2 removal process (Powerspan)
EIA .... Energy Information Administration (DOE)
EIEA .... Energy Improvement and Extension Act
EOR .... enhanced oil recovery
EPA .... U.S. Environmental Protection Agency
EPRI .... Electric Power Research Institute
ERR .... estimated recoverable reserve

°F .... degrees Fahrenheit
FCA .... fuel cost adjustment
FERC .... Federal Energy Regulatory Commission
FGD .... flue gas desulfurization
FGR .... flue gas recirculation
FLPMA .... Federal Land Policy and Management Act of 1976

GHG .... greenhouse gas
GRE …………..Great River Energy
GW .... gigawatt

H_2 .... hydrogen
Hg .... mercury
H_2O .... water
HHV .... higher heating value
H_2S .... hydrogen sulfide

ICAC ....Institute of Clean Air Companies
IEA ....International Energy Agency
IGFC............integrated gasification fuel cell
IGCC ....integrated gasification combined cycle
IOGCC ....Interstate Oil and Gas Compact Commission
IP........................intellectual property
IPR....................intellectual property right
IPR™................Integrated Pollutant Removal technology
IRR ....internal rate of return
ITC ....investment tax credit
ITM...................ion transport membrane (Air Products and Chemicals)

LCFS ....low carbon fuel standard
LCOE ....levelized cost of electricity
LHV ....lower heating value
LP ....low pressure

Mcf....................thousand cubic feet
MEA ....monoethanolamine
MHI ....Mitsubishi Heavy Industries
MIT..............Massachusetts Institute of Technology
MLA ....Mineral Leasing Act
MVA ....monitoring, verification and accounting
MW, MWe ....megawatt, electrical
MWth ....megawatt, thermal
MWh.................megawatt-hour

N_2 ....nitrogen
NAS...................National Academy of Sciences
NEPA................National Environmental Policy Act
NETL................National Energy Technology Laboratory (DOE)
NH_3 ....ammonia
NOx...................nitrogen oxides
NPV ....net present value
NRC.............National Research Council

O_2......................oxygen
OECD ....Organisation for Economic Cooperation and Development
O&M...............operations and maintenance
OPEC ....Organization of Petroleum Exporting Countries
OPS ....Office of Pipeline Safety

PC.....................pulverized coal
PHMSA...........Pipeline and Hazardous Materials Safety Administration
PM....................particulate matter
ppmv............parts per million by volume
PRB ....Powder River Basin
PSD ....Prevention of Significant Deterioration
psi ....pounds per square inch
PV.....................present value

RCRA ....Resource Conservation and Recovery Act
R&D ....research and development
RD&D ....research, development and deployment
RCSP...............Regional Carbon Sequestration Partnership
RFS ....renewable fuel standard

Scf.....................standard cubic foot
SCPC...............supercritical pulverized coal
SDWA ....Safe Drinking Water Act
SNG.................substitute (or synthetic) natural gas
SO_2 ....sulfur dioxide
SPC ....Supreme People's Court (China)
STB ....Surface Transportation Board

T ....temperature
TBD.................to be determined

tcf ....trillion cubic feet
TCR ....total capital requirement
TIFI® ....Targeted In-Furnace Injection (Fuel Tech)
TWh..................terawatt-hour

UCG..................underground coal gasification
UIC ....underground injection control
UOP ....Universal Oil Products
USCPC ....ultra-supercritical pulverized coal

WGS ....water gas shift

Executive Summary

During the May 15, 2009 meeting of the National Coal Council, Secretary of Energy Steven Chu asked the Council to "conduct a study on the value and use of coal in a carbon constrained energy market", in order to demonstrate how the research, development and widespread deployment of commercial-scale technologies for CO_2 capture and storage (CCS) on existing and new coal-based generating plants would play a major role in achieving President Obama's stated goal of an 80% reduction in CO_2 emissions by the year 2050.

In his follow-up letter, the Secretary clarified the Administration's goal for reductions in CO_2 emissions as soon as possible from the existing fleet of coal-based electricity generation, stating *"The report should examine varying amounts of CO_2 capture to explore whether there may be advantages to initially capturing lower amounts of CO_2, for example 50-60 percent. The report should also examine capturing CO_2 at 80-90 percent and higher levels and examine the costs associated with multiple levels of capture"*.

Significant, near-term reductions in CO_2 emissions from a portion of the existing coal-based generating fleet could be achieved by: 1) retrofit technologies which improve generation efficiency, thereby lowering the amount of coal used for the same amount of electricity generated, 2) using partial CO_2 capture technologies (i.e. 50-60%), or 3) a combination of efficiency improvements and partial CO_2 capture. These technologies are available now. While the investment costs will be significant, we do not need to wait until the higher CO_2 capture rate technologies begin to be deployed at large scale later in the decade. Higher efficiency, partial CO_2 capture, and having at least 10 large-scale CCS demonstration projects in operation by 2016 are crucial steps in meeting the President's goal of an 80% reduction in CO_2 emissions by 2050. These are important and necessary investments in the energy future of our nation.

The report makes clear that coal-based generation with CCS will enable the U.S. to meet the President's twin goals of an 80% reduction in CO_2 emissions amid sustained economic and employment growth. Secretary Chu (October, 2009) has called for the widespread deployment of CCS to "begin within 8 to 10 years". The National Research Council (NRC, 2009) has indicated that over the next several decades, coal-based generation with CCS can replace the existing coal fleet and provide up to **3,000 Terawatt-hours** (TWh) of electricity per year at affordable rates. The construction of about 360 gigawatts (GW) of coal-based generation with CCS by 2050 will open up a new horizon for clean and sustainable energy at reasonable cost.

This effort will require a significant investment, and the report estimates that $1.2 trillion will be required to support widespread deployment of about 360 GW of coal-based generation with CCS by 2050. Such a construction program will revitalize the industrial sector of America, provide over **28 million job-years** spanning four decades and increase our nation's Gross Domestic Product by more than **$2.7 trillion** -- a remarkable payoff for a $1.2 trillion investment. Research conducted for the AFL-CIO (2009) indicates operation and maintenance of these facilities will provide over **800,000 permanent jobs** throughout the economy---thereby benefiting generations of Americans yet to come. Finally, the CO_2 captured from these plants would support a robust enhanced oil recovery (EOR) program, providing at least **2 million barrels of oil per day**, enhancing national security and making a contribution to the CO_2 emission reduction goals. The National Energy Technology Laboratory (NETL, 2009) has indicated that the next generation of CO_2-EOR technology alone would create a demand for captured CO_2-- roughly equal to the CO_2 emissions from about 70 GW of coal-based power plants over a 30-year period.

Since World War II, coal has been used to produce about half of America's electricity. In 2008, over one billion tons of coal was utilized to produce almost 2,000 TWh per year of electricity. Additional generating capacity will be needed in the U.S. over the coming decades for a number of reasons including: 1) growing demand due to increases in population and from economic growth, 2) replacement of retiring power generating units, 3) increasing reliance on electro-technologies, and 4) the movement to electrify the transportation system.

Based on a scenario developed by the NRC, the U.S. has the coal resources to provide the 1.7 billion tons of coal-based generation with CCS required to produce up to 3,000 TWh per year of electricity -- while at the same time meeting the President's CO_2 emission reduction goals and increasing domestic oil production. In fact, based on the NRC and NETL analyses, there would be a robust new economic market created for the EOR use of the CO_2 captured from the consumption of over 360 million tons of coal per year. Additional CO_2 will be required for other value-added beneficial reuse opportunities, ranging from the production of cement to the production of iron oxide.

Many political leaders and energy organizations around the world, including the European Union and the International Energy Agency (IEA), also have CO_2 emission reduction goals, and recognize that widespread deployment of CCS technology is the key method for achieving significant, long-term global reductions in CO_2 emissions. These leaders also recognize that coal-based technologies that employ CCS will be among the lowest cost, low-carbon alternatives for electricity generation and for energy supply. This recognition is exemplified in a joint statement signed by President Obama and Chinese President Hu Jintao in November, 2009 in Beijing: "The two sides strongly welcomed work in both countries to promote 21st century coal technologies. They agreed to promote cooperation on large-scale carbon capture and sequestration (CCS) demonstration projects and to begin work immediately on the development, deployment, diffusion, and transfer of CCS technology." A key indicator of this cooperation is the recent agreement between companies in the U.S. and China regarding the construction of GreenGen-- a coal-based CCS facility in Tianjin.

This report makes clear that cooperative efforts with China and other developing nations are an essential component for achieving global CO_2 emission reductions. Since technology transfer is a vital part of these efforts, and American companies need to be able to participate on an equitable basis to address global CO_2 emission reductions, and for the economic well-being of our nation, the U.S. must ensure that American companies' intellectual property rights for CCS technologies are adequately protected around the world.

The findings and recommendations provided in the present report will be of major assistance to the Secretary of Energy (as well as other Federal agencies) in meeting the long-term CO_2 reduction goals of the President, while at the same time protecting the environment, maintaining economic health, and enhancing the U.S. position of technological leadership.

The report also addresses CO_2 capture technologies, pipeline transportation of CO_2, use of CO_2 for EOR, and deep saline injection and other geological storage options. Technology suppliers active in the development and use of these technologies have added real-world experience to this report. The report also evaluates how CCS technologies will be applicable to the next generation of higher efficiency coal-based plants.

The world and the U.S. will not only continue to use coal, but will use it in increasing amounts. In the U.S., CCS will be required if this increase in coal use is to occur in the context of the President's long-term CO_2 emission reduction goal. The widespread deployment of CCS will require large investments and take time, but it will pay significant dividends. This report provides the path to achieve the President's goals of reducing CO_2 emissions while maintaining economic growth.

Topic Areas Covered in This Report

Following are the major topic areas addressed in this report.

1. The Energy Context of Coal-Based Generation With CCS
2. Timeline and Costs for Commercial-Scale CCS Deployment
3. Retrofitting the Existing Coal-based Generating Fleet to Increase Efficiency and Decrease CO_2 Emissions
4. Technologies for the Capture of CO_2
5. Securely Storing CO_2
6. Legal/Regulatory Issues
7. Coal Beneficiation Reduces CO_2 Emissions from the Overall Coal-to-Electricity Process
8. Underground Coal Gasification
9. The U.S. as the Technology Leader

The report provides technical descriptions, costs and timelines for the research, development and commercial-scale deployment of CCS technologies, on a path that will provide the reductions in CO_2 emissions needed to achieve the President's goals. In order to provide clear, concise guidance, this Executive Summary provides the findings from each major section of the comprehensive report, along with the recommendations of the National Coal Council to the U.S. Department of Energy (DOE), as well as to other Federal agencies and the U.S. Congress, for the actions that will be necessary to bring these technologies to commercial scale and achieve the President's goals.

Key Findings and Recommendations

Section 1 - The Energy Context of Coal-based Generation with CCS

Findings

- Coal provides more than 50% of America's electricity and is the key to meeting the unprecedented and continuing rise in global energy demand.
- The President seeks to both maintain economic growth and reduce greenhouse gas (GHG) emissions 80% by 2050.
- Coal-based generation with CCS is widely recognized as the principal means of meeting both the President's economic and CO_2 emission reduction goals in a timely and affordable manner.
- The investment in coal-based generation with CCS will: 1) enable the U.S. to meet increasing electricity demand and 2) strengthen national security by providing CO_2 necessary for EOR within the U.S.
- Extensive deployment of coal-based generation with CCS will have far-reaching socioeconomic benefits, yielding **over 28 million job-years** from new construction and revitalizing the industrial sector of the U.S. GDP will be increased by **$2.7 trillion.** Further, continuing operation and maintenance of the facilities would support over **800,000 permanent jobs.**
- Associated EOR projects could yield over **2 million barrels per day of oil**. NETL (2009) has indicated the next generation of CO_2-EOR technology alone would create a demand for captured CO_2 -- roughly equal to the emissions from up to 70 GW of coal-based power plants over a 30-year period. Thus, the CO_2 demand from EOR alone would equal the CO_2 captured from consuming over 360 million tons of coal per year.
- The coal resource to achieve long-term goals exists. The Estimated Recoverable Reserve of the U.S. is 265 billion tons, distributed across at least 31 states.

Recommendations

- The Council fully supports implementation of the DOE plan to have 10 large-scale CCS demonstration projects on line by 2016, with the goal of initiating widespread deployment of coal-based generation with CCS at commercial scale in the next 8-10 years.
- The Council recommends that the DOE work with other relevant groups to implement the National Research Council's conclusion that the existing coal-based generation fleet can be fully replaced by a combination of retrofitted, repowered and new coal-based generation with CCS.
- The Council recommends that the DOE work with other relevant groups to enable the production of 2 million barrels of oil per day through CO_2-based EOR.

Section 2 – Timeline and Costs for Commercial-Scale CCS Deployment

Findings

- Secretary Chu (2009) laid out an aggressive timeline to have up to 10 commercial-scale CCS demonstration projects in operation by 2016 and to begin widespread and affordable deployment of CCS within 8 to 10 years. With sufficient funding and an immediate start, the timeline discussed in this report is generally consistent with the Secretary's goals.
- Commercial-scale deployment of CCS technology is contingent on a successful "Pioneer Plant" phase in which 5-7 GW of CCS capacity is built. These pioneer plants could complete four years of operation and monitoring of the CO_2 storage sites by about 2020, but funding sources to accomplish this are inadequate at present, and would require congressional action.
- Following the Pioneer Plant phase, potential owners should have sufficient confidence in CCS to build about 60 GW of commercial-scale "Early Adopters" but they would require adequate and appropriate financial incentives (as discussed below) to justify the investment. If commercial-scale facilities could be built at the highest historical power plant capacity addition rates in the U.S., 60 GW of coal-based generating capacity (including 7 GW of Pioneer Plants) with CCS could be on line by 2030-35 and the U.S. coal-based generating fleet could be replaced with CCS-equipped capacity by 2050. This assumes an immediate start of the Pioneer Plant phase, and that non-technical issues including legal, regulatory, permitting, liability, and financial factors do not impede commercial-scale CCS deployment.
- Based on cost estimates by the Electric Power Research Institute (EPRI), the incremental capital cost (relative to new plants without CCS) for 7 GW of CCS Pioneer Plants is about $12 billion, and for the 53 GW in the Early Adopter phase is about $75 billion (all in 2007 dollars). The annual increment of the Levelized Cost of Electricity (LCOE) would be about $2.4 billion for the Pioneer Plant and about $15 billion for the Early Adopters. These CCS costs are competitive with the range of costs of alternative technologies proposed to meet the President's goal to "decarbonize" the electricity generating system.
- CCS projects that are dependent in the short term or long term on investment by regulated utilities, non-regulated utilities, other energy companies and private individuals must fall within reasonable risk guidelines and provide an internal rate of return (IRR) at or exceeding 20 percent per annum in order to attract investment.
- The insurance industry will not commit capital to long-term CCS projects without well-defined roles for government and an understanding of how liability is addressed, but will support the CO_2 capture and transportation phase of CCS projects, based upon current engineering/underwriting considerations.

Recommendations

- The DOE should expand the CO_2 storage tests currently being conducted under the Regional Carbon Sequestration Partnership program to larger, longer duration injection tests in a wider range of geologic and oil/gas/coal fields and fund characterizations of 5-10 potential commercial scale CO_2 storage sites. This information will be critical to making commercial investment decisions, and for developing the regulatory, permitting, legal and financial structures needed for CCS to be widely deployed.

- The DOE should design and determine the costs, timing and co-funding requirements of a "Pioneer Plant" program to achieve about 7 GW of coal-based power generation facilities integrated with CCS with the goal of achieving four years of operation and storage site monitoring by 2020. The Pioneer Plants should be geographically diverse and encompass a range of coals, CO_2 capture and electricity generating technologies, and geologic storage sites. Funding for these Pioneer Plants will require timely legislative action.
- The DOE should continue and expand research to improve the performance and reduce the cost of CCS for greenfield and retrofit applications. This should include expedited testing at pilot and larger scale of promising CO_2 capture technologies.
- Legislation or relevant agency actions at DOE and elsewhere are needed to:
  – Create an appropriate mix of medium to high levels of financial incentives to stimulate investment in CCS projects.
  – Define the responsibilities/liabilities, including federal and state regulatory cognizance associated with long-term CO_2 storage facilities. This should involve consideration of previously established models to fund or insure the liabilities associated with these facilities.
  – Encourage alternatives to long-term CO_2 storage, such as CO_2 reuse in industrial processes, which should be explored to alleviate legacy liabilities.

Section 3 – Retrofitting the Existing Coal-based Generating Fleet to Increase Efficiency and Decrease CO_2 Emissions

Findings

- Commercially-available technologies could be retrofitted today to a large portion of existing coal-based power plants; increasing their efficiency by only 1-2% would result in near-term reductions in CO_2 emissions of 20-40 million tons per year. Retrofitting combinations of these technologies on existing plants would provide significant additional reductions.
- Until high CO_2 removal rate and CO_2 storage technologies are commercially available and proven at large scale, partial CO_2 capture (i.e. 40-60%) could provide additional near-term reductions in CO_2 emissions from the existing coal-based generating fleet. This could be accomplished by the installation of high removal rate CO_2 capture systems on a slipstream of each plant's exhaust gases.

- Together, the combination of high efficiency retrofits and partial CO_2 capture would result in significant near-term reductions in CO_2 emissions from the existing coal-based generating fleet.
- There is a need for economic incentives and regulatory changes that will encourage electric utilities to undertake these large capital expenditures solely for the purpose of meeting the President's goal of reducing CO_2 emissions.

Recommendations

- In order to achieve the President's goal of near-term reductions in CO_2 emissions from the existing coal-based generating fleet, the Council recommends that Congress and the DOE provide economic incentives to encourage the retrofit of efficiency-improving technologies and/or partial CO_2 capture technologies to the existing coal-based generating fleet.

Section 4 – Technologies for the Capture of CO_2

Findings

- Due to the growing U.S. and worldwide dependence on coal for the generation of electricity, CCS can and must be an important component of the Administration's effort to reduce overall CO_2 emissions.
- A variety of CO_2 capture technologies are being developed and demonstrated. Many of these technologies hold the promise of providing cost-effective application of CCS for electric power generation.
- For the goal of 90% CO_2 capture and storage from coal-based power plants to be commercially available in the 2020-2025 period, additional government support is necessary for technology demonstration at the commercial scale.
- In the near term, partial CO_2 capture (e.g. 50%), along with efficiency improvements, can serve as an important intermediate step; this will reduce investment risks and lessen the most significant impacts on plant performance and efficiency.
- The 2009 Clean Coal Power Initiative (CCPI) selections represent the first round of projects that will be necessary to demonstrate integrated CCS technologies. The CO_2 capture technologies demonstrated represent the current state-of-the-art for implementation at commercial scale. These projects will yield valuable information on the operation and integration of these advanced technologies with CO_2 compression and storage operations.

Recommendations

- Due to the complexity and variability of coal-based power plants, it is imperative that a variety of CCS technologies be available to the industry. To support this, the DOE should expand the Clean Coal Power Initiative (CCPI) and plan for additional rounds of the CCPI to allow for opportunities to demonstrate technologies that have matured

through R&D to the commercialization stage. The DOE should also develop more consortia-matching projects (like FutureGen) that will support commercial-scale demonstration of promising CCS technologies.
- To continue progress with development of commercial-scale integrated gasification combined cycle (IGCC) with CCS, the Council recommends that the DOE continue to support the FutureGen program, in order to demonstrate high hydrogen (H_2) combustion turbine technology.
- The Council recommends that the DOE increase its financial support for research and development (R&D) to develop improved high-temperature and pressure materials and validate the use of these advanced materials for boilers, turbines, and other critical components to support the advancement of new higher efficiency power generation equipment.
- The Council recommends that the DOE streamline the application, selection and funding processes associated with the CCPI and demonstration programs.

Section 5 – Securely Storing CO_2

Findings

- CO_2 has been successfully transported on a commercial basis for over thirty years with the majority of the CO_2 having been used for EOR.
- CO_2 captured from fossil fuel combustion may contain some level of impurities, depending on separation technologies employed, which will need to be considered with respect to transport pipeline materials, compressor design and storage sites.
- Geological CO_2 storage capacity in the U.S. is geographically wide-spread and represents centuries of storage capacity. The DOE's establishment of the seven Regional Carbon Sequestration Partnerships has been very successful in addressing many of the issues surrounding CO_2 storage, but more work is required to qualify tests and develop more and better data from large-scale (>1 million tons/year) demonstrations.
- One of the biggest challenges facing geological storage is the custody and liability issues for the operation and long-term geologic storage of CO_2 at closed-out commercial-scale sites.
- Public outreach and education will be required on a massive scale to reassure the public that CCS can be safely deployed.
- Beneficial use technologies face both technical and economic hurdles to scale-up and to achieve widespread deployment, but they offer a permanent solution to CO_2 emission reductions.

Recommendations

- The Council recommends that the DOE continue its work on commercial-scale CCS demonstrations.

- The Council recommends that the DOE continue its efforts to more fully characterize and document the available geological formations available for CO_2 storage and continue its efforts to better understand the effects of CO_2 storage on geological formations, such as swelling impacts on permeability.
- The Council recommends that the DOE continue to work with other Federal agencies on issues such as long-term liability, and public education and outreach. DOE's CCS expertise can be of enormous assistance to other federal agencies tasked with various CCS-related regulatory requirements.
- The Council recommends that the DOE spearhead the cataloguing of available information to compare and contrast beneficial use technologies and conduct tests to determine which are the most promising. This would expedite the determination of which alternatives are most economically attractive, based on the specific circumstances of a company or plant.

Section 6 – Legal/Regulatory Issues

Findings

- In order for CCS to be deployed in a safe and timely manner, several legal and regulatory issues must be addressed. The bulk of the needed legal work involves CO_2 injection and storage, with long-term stewardship considerations at storage sites a priority.
- Led by many States and the EPA, an appropriate legal and regulatory framework for CO_2 injection and storage is starting to take shape. The States' roles in CCS regulation should not be underestimated given the successful role that they have played in safely regulating comparable injection and storage activities.
- There are no federal laws governing long-term CO_2 storage. Many States already have adopted comprehensive long-term storage regimes that should be sufficient to enable the permitting of storage operations at early mover CCS projects.
- The DOE must play a leading role in ensuring that CCS is regulated in a manner that protects human health and the environment while enabling worthwhile projects to be financed, developed and operated without unnecessary legal impediments.

Recommendations

- Federal or State governments, or both, must adopt mechanisms by which responsibility for long-term stewardship at storage sites – including both operational responsibilities and liabilities -- is shifted from the private sector to the public sector. Numerous States already have adopted such approaches, and the U.S. Senate has before it bills that would provide a complementary federal role for long-term stewardship.
- CO_2 injection and storage must be subject to stringent, and hopefully unified, permitting under federal and State law.
- Exempting appropriately permitted injection and long-term storage activities from the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) would be

worthwhile because neither statute creates an appropriate regulatory and/or liability regime for geologic injection and storage.

- Congress should clarify the requirements that apply to CO_2 injection and storage on federal lands by, for example, stipulating pore space ownership and amending the Federal Land Policy Act and the Mineral Leasing Act to explicitly allow long-term CO_2 storage under federal leases.

Section 7 – Coal Beneficiation Reduces CO_2 Emissions from the Overall Coal-to-electricity Process

Findings

- Coal beneficiation technologies improve the quality of coal by reducing its ash and moisture contents, and help to achieve the President's goal by reducing CO_2 emissions from the transportation and handling of coal.
- The use of beneficiated coal improves the efficiency of power generation, thereby lowering emissions of CO_2.
- The use of beneficiated coal results in a simultaneous reduction in multiple emissions, including CO_2.
- Coal beneficiation technologies are compatible with the existing coal-based generating fleet, regardless of age, type of boiler, emission control equipment, fuel type or location.

Recommendations

- The Council recommends that the DOE ensure that coal-based units receive credit for CO_2 emission reductions achieved through the use of beneficiated coal technologies.
- The Council proposes that DOE open up a funding solicitation under the CCPI or through EPAct 2005's Loan Guarantee Program, focused on the accelerated development and commercial deployment of coal beneficiation technologies.

Section 8 –Underground Coal Gasification

Findings

- Underground coal gasification (UCG) has the potential to yield access to the energy of hundreds of billions of tons of unmineable coal in many countries, but especially in China, India, Russia, Australia, the U.S. and Western Europe.
- UCG offers the potential to gasify coal economically and to produce a wide range of feedstocks and raw materials for economic expansion.

- UCG appears to be especially amenable to CCS because the CO_2 can be stored in the cavities formed by UCG. UCG can produce fewer emissions than conventional combustion and there is evidence that these emissions are more easily controlled.
- A confluence of energy, economic and environmental benefits make UCG an important pathway in providing energy while meeting climate change policy goals. The state of knowledge in UCG is not nascent, but rather has been developed through a variety of projects in different geological settings since the 1930s. Nevertheless, more extensive and systematic research is needed to fully assess the potential of UCG.

Recommendations

- The Council recommends that a four-year UCG program similar to that proposed by the Clean Air Task Force (2009), be implemented as soon as possible – including the development of up to five commercial scale projects within the U.S.

Section 9 – The U.S. as the Technology Leader

Findings

- The U.S. and China have emerged as the global leaders in clean coal technologies, but other countries have also made progress over the last decade.
- Nevertheless, technology transfer from the U.S. is vital to the effort to reduce global emissions of CO_2.
- This transfer will not occur at required levels unless intellectual property rights for CCS technologies are honored and protected throughout the world.
- The opportunities of such cooperation were recently demonstrated by the joint venture agreement between companies in the two countries relating to GreenGen, a $1 billion coal-based power plant with CCS scheduled for operation in Tianjing in 2011. Secretary Chu participated in the signing ceremony in Beijing in November, 2009. This cooperation was further solidified in a joint statement signed by both President Obama and President Hu Jintao.

Recommendations

- The Council recommends that DOE work with other parts of the Administration to strengthen and enhance the cooperation symbolized by the Joint Agreement between President Obama and President Hu Jianto.
- The Council recommends that the DOE support the position that all nations bear the greater share of the economic burden of CO_2 mitigation within their own borders.
- The Council recommends the DOE play a leading role in the Administration’s effort to ensure that intellectual property rights for CCS technologies developed by American companies are fairly protected in other countries.
- The Council recommends that the DOE play a leading role within the Administration in developing an equitable international framework to enable widespread and affordable deployment of CCS to begin within 8 to 10 years.

1 The Energy Context of Coal-based Generation with CCS

"The challenge before us is to transform the U.S. energy system in a manner that increases its sustainability, supports long-term economic prosperity, promotes energy security, and reduces the adverse environmental impacts arising from energy production and use" (National Research Council, 2009)

Findings

- Coal provides more than 50% of America's electricity and is the key to meeting the unprecedented and continuing rise in global energy demand.
- The President seeks to both maintain economic growth and reduce GHG emissions 80% by 2050.
- Coal-based generation with CCS is widely recognized as the principal means of meeting both the President's economic and CO_2 emission reduction goals in a timely and affordable manner.
- The investment in coal-based generation with CCS will: 1) enable the U.S. to meet increasing electricity demand and 2) strengthen national security by providing CO_2 necessary for EOR within the U.S.
- Extensive deployment of coal-based generation with CCS will have far-reaching socioeconomic benefits, yielding **over 28 million job-years** from new construction and revitalizing the industrial sector of the U.S. GDP will be increased by **$2.7 trillion.** Further, continuing operation and maintenance of the facilities would support over **800,000 permanent jobs.**
- Associated EOR projects could yield over **2 million barrels per day of oil**. NETL (2009) has indicated the next generation of CO_2-EOR technology alone would create a demand for captured CO_2 -- roughly equal to the emissions from up to 70 GW of coal-based power plants over a 30-year period. Thus, the CO_2 demand from EOR alone would equal the CO_2 captured from consuming over 360 million tons of coal per year.
- The coal resource to achieve long-term goals exists. The Estimated Recoverable Reserve of the U.S. is 265 billion tons, distributed across at least 31 states.

Recommendations

- The Council fully supports implementation of the DOE plan to have 10 large-scale CCS demonstration projects on line by 2016, with the goal of initiating widespread deployment of coal-based generation with CCS at commercial scale in the next 8-10 years.
- The Council recommends that the DOE work with other relevant groups to implement the National Research Council's conclusion that the existing coal-based generation fleet can

be fully replaced by a combination of retrofitted, repowered and new coal-based generation with CCS.
- The Council recommends that the DOE work with other relevant groups to enable the production of 2 million barrels of oil per day through CO_2-based EOR.

1.1 Coal-based Generation with CCS is Both a Goal and an Opportunity

> **"I believe we must make it our goal to advance carbon capture and storage technology to the point where widespread, affordable deployment can begin in 8 to 10 years" (Steven Chu, Secretary of Energy, October 12, 2009)**

As this report demonstrates, the technologies to begin deploying coal-based power generation with improved generation efficiency and partial CO_2 capture at large, commercial scale are both available and affordable now. Indeed, the National Research Council (NRC), in its major report *America's Energy Future* (2009), clearly recognizes the potential of coal-based generation with CCS as the primary source of electric capacity additions over the foreseeable future with the ability to provide up to 3,000 Terawatt-hours (TWh) of electricity per year:

"Coal fired plants with CCS could provide as much as 1200 TWh from repowering and retrofit of existing plants and as much is 1800 TWh from new plants. In combination, the entire existing coal power fleet ... could be replaced by CCS coal power" (NRC, 2009).

The NRC report goes on to stress the importance of rapidly implementing CCS as the primary means of meeting climate change policy goals: "The failure to successfully demonstrate the viability of these technologies during the next decade will greatly restrict options to reduce CO_2 emissions from the electricity sector" (NRC, 2009).

Secretary Chu's October 12, 2009 commitment to bring up to 10 commercial demonstration projects online by 2016 is a crucial step in realizing the potential of coal-based power generation with CCS as identified in the NRC vision of America's energy future. As the implementation of CCS technologies moves forward over the period 2010 to 2050, it will bring far-reaching socioeconomic benefits to the quality of life in America. An investment of $1.2 trillion to support widespread deployment of about 360 GW of coal-based generation with CCS by 2050 will open up a new horizon for clean, affordable and sustainable energy and will:

- Provide the best opportunity to meet or exceed the President's goal of 80% reduction in CO_2 emissions by 2050
- Assure energy security by providing a reliable domestic fuel supply with the ability to meet the large baseload demand now satisfied by conventional coal-based power plants
- Provide up to 3,000 TWh per year of affordable electricity, following the NRC conclusion that coal-based power generation with CCS is highly competitive with other low-cost, low carbon sources of electricity

- Yield 28 million construction related job-years over a 40-year period and support up to 800,000 jobs per year through the operation and maintenance of these new facilities
- Increase Gross Domestic product in the U.S. by $2.7 trillion
- Provide CO_2 to enable EOR of over 2 million barrels/day of stranded oil, as well as significant amounts of enhanced coalbed methane recovery
- Provide CO_2 for beneficial uses ranging from production of cement to iron oxide
- Revitalize the manufacturing sector of the U.S. through the construction and operation of coal production and transportation facilities, power plants and CCS equipment, pipelines, CO_2 permanent storage sites and EOR facilities.

For over 150 years, coal has been the energy workhorse for America, providing reliable and affordable energy to businesses, institutions and families across the Nation. With the CCS technology demonstration and deployment goals delineated by Secretary Chu, the U.S. will be able to expand utilization of our most important energy resource and give added meaning to the term “Made in America.”

1.2 The Goals Have Been Delineated

President Obama and Secretary Chu have both set an 80% reduction of CO_2 emissions by 2050 as a fundamental goal of energy policy in the U.S.

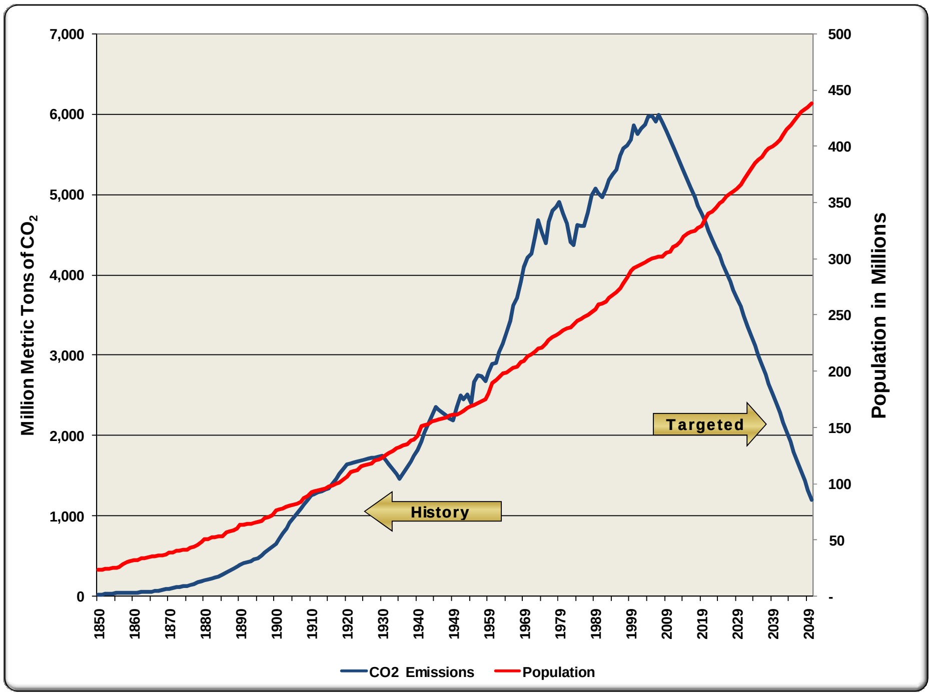
> **“I've put forward very substantial proposals to get 80 percent reductions in greenhouse gasses by 2050”**
> **(President-elect Obama, 2008)**

At the same time, a parallel goal of the Administration is the resumption and expansion of economic progress:

> **“Each policy we pursue is driven by a larger vision of America’s future – a future where sustained economic growth creates good jobs and rising incomes” (President Obama, 2009)**

Both of these policy goals will take place in the context of continuing population growth as the number of people in the U.S. will increase from a current 307 million to almost 440 million by 2050 (see Figure 1-1). The divergent context of these changes puts the magnitude of the task before us in perspective.

FIGURE 1-1
The Scale of the Challenge



Sources: EIA (2009); Pew Foundation Research (2008)

1.3 Striking a Balance

Energy is the linchpin in socioeconomic development, transforming agrarian societies to modern industrial ones. This societal transformation, driven by the accumulation of income and wealth, eliminates many contagious diseases, reduces child mortality, and lengthens adult life expectancy. This virtuous cycle has been demonstrated over the past two centuries worldwide. The emergence from poverty begins as countries develop transportation systems, generally using petroleum-based fuels, and electricity networks, often based upon coal-based power generation. These systems are capable of achieving the massive economies of scale that provide large amounts of energy at low cost. These abundant and reliable supplies of energy spur technological change, enhance productivity growth, and increase living standards.

The President has set a goal of reducing CO_2 emissions, but CO_2 is the inevitable by-product of combusting fossil fuels in an industrialized economy. About 70% of U.S. electricity is generated from fossil fuels and about 50% of all electricity is provided by coal-based generation. This energy production yields significant benefits for the health and welfare of all Americans, but it also results in CO_2 emissions.

It is important to strike a balance between the powerful benefits of electricity generation from fossil fuels and the President's goal of reducing CO_2 emissions. Electricity produced from fossil fuels -- particularly coal -- has been, is and will continue to be the cornerstone of modern life. Further, the world is turning to even more coal use to meet the growing need for electricity. The benefits of coal-based electricity have been demonstrated by remarkable socioeconomic progress first in the U.S. and currently in China.

"Electrification in China is a remarkable success story… the electrification goal [is] part of its poverty alleviation campaign… the most important lesson for other developing countries [is] that electrified countries reap great benefits, both in terms of economic growth and human welfare… China stands as an example" (IEA, 2007)

India and the rest of the world now seek the same benefits and are building coal-based power plants. Further, this pattern will continue as countries with increasing energy requirements utilize their most available and affordable resource – coal. Coal is mined commercially in more than 50 countries. Reserves are vast and geographically diverse, and readily available to a variety of nations both large and small, developed and emerging, on every major continent. Trade flows are well-established and a reliable infrastructure is in place.

1.4 Energy is the Essential Basis for the Global Quality of Life

Adequate, reliable and affordable energy is the linchpin to "more people, living better, living longer". The National Academy of Engineering (2004) has identified societal electrification as the "most significant engineering achievement" of the 20th century. In fact, virtually all of the other major engineering achievements identified by the Academy would have been impossible without electricity. As William Ramsay, Deputy Executive Director of the IEA has stated: "Electricity is the leading indicator of growing prosperity and the principal driver of a modern society" (2008).

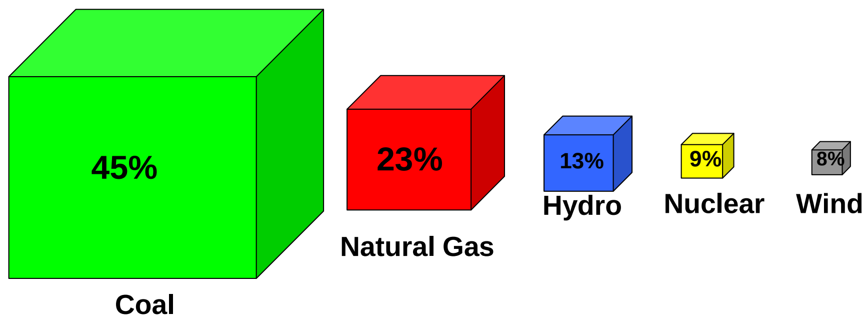
In fact, electricity and other forms of energy are so important consumption is ever growing. In the U.S., the Energy Information Administration (EIA) has projected a 9% rise in domestic energy consumption by 2030 and a 22% increase in electricity demand.

But a much larger drama is being played out on the global level. At least 3.6 billion people -- 12 times the population of the U.S. -- lack adequate access to electricity and 1.6 billion have no access at all. Hundreds of millions of women, men, and children toil grimly in the dark, lacking the basic necessities of life -- clean water, safety, fuel and light. The EIA projects that by 2030, global energy consumption will increase 43% and demand for electricity will grow over 75%.

Coal will be the continuing cornerstone of this energy -- currently providing 41% of global electricity and projected to provide 43% by 2030. As the current century proceeds, generation of electricity is poised for dramatic growth. The EIA (2008) predicts a 75% increase in the next two decades alone. The locus of that incremental growth reflects a major shift in the global situation. From 1980-2000, almost one fourth of the global increase in generation came from the U.S. Over the next 20 years, the U.S. will be a relatively minor player in an ever larger drama. The projected increase in electricity consumption is staggering, and more than 90% of that growth will be outside the U.S.

Further, over two thirds of that incremental power will come from fossil fuels -- especially coal, which will account for 45% (see Figure 1-2).

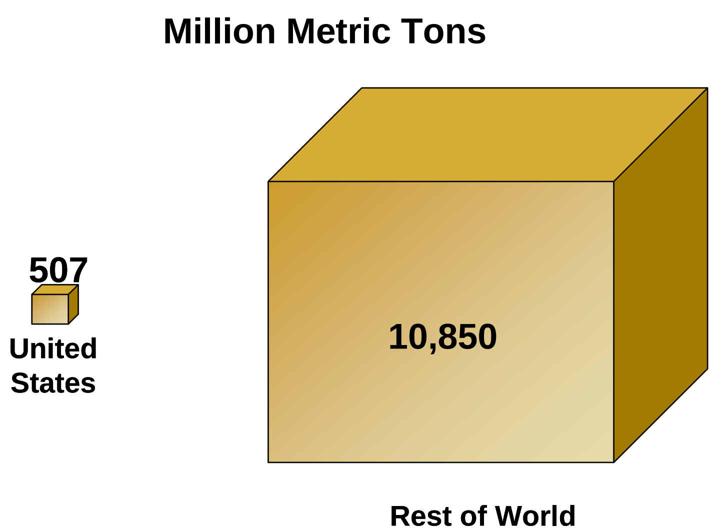
FIGURE 1-2
The Sources of the World's Incremental Electricity Generation



Source: EIA (2009)

These global patterns of incremental electricity production make the widespread deployment of CCS even more important to the extent the President desires to have a worldwide impact in reducing CO_2 (see Figure 1-3).

FIGURE 1-3
Projected Global Incremental CO_2 Emissions (2006-2030)

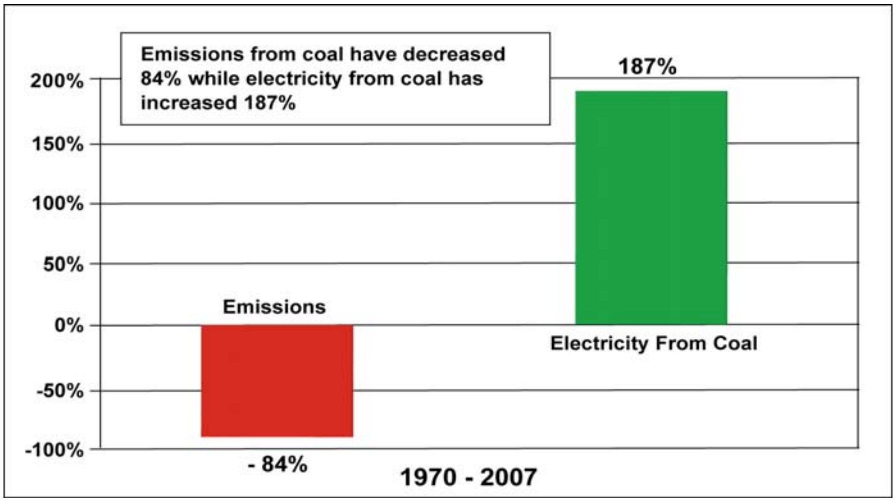


Source: EIA (2009)

1.5 Clean Coal Technologies are Opening the Door to Energy Stability and Economic Growth

Clean coal technologies work. Since 1990, the U.S. electric power industry has invested almost $100 billion to control emissions with stunning success (Hewson and Stravinsky, 2008). As Figure 1-4 shows, criteria emissions such as sulfur dioxide (SO_2) and nitrogen oxides (NOx) have declined significantly since 1970, despite a dramatic increase in coal-based generation. Clean coal technologies have solved other emissions challenges, and now the creative gaze of the scientific and engineering community has turned to the challenge of meeting the President's CO_2 emission reduction goal.

FIGURE 1-4
The Dramatic Success of Clean Coal Technologies in Reducing Emissions



Source: Calculated from EIA data and reports

As the National Energy Technology Laboratory (NETL, 2009) has stated: "With coal likely to remain one of the nation's lowest cost electric power even more advanced clean coal technologies are needed."

Increasing opportunities surround two associated continuously evolving technologies: 1) increased efficiency and 2) CCS. The synergies between these two processes will help the nation and world solve constraints in electricity, natural gas, and liquid fuel supplies. In regard to efficiency, the Coal Industry Advisory Board (2009) has stated: "Improving the efficiency of both existing and future coal-fired power plants has the potential to generate significant and cost-effective emissions reductions: and must be a priority for all coal using countries."

The Council has followed this line of reasoning and previously submitted a series of reports to the Secretary of Energy delineating how the U.S. can use coal to solve many of our most pressing energy needs regarding electricity, liquid fuels, and natural gas. These reports deal with a variety of issues but have one common theme -- how coal can be used to meet both environmental and economic goals.

- 2000 -- "It is imperative that CO_2 sequestration and generation efficiency become high priorities for Department of Energy research."
- 2003 -- "The Department should expedite research on a wide range of CO_2 capture options and expand the core R&D and demonstration programs."
- 2006 -- "The U.S. must develop strategies to adopt CCS technologies…By ardently pursuing the required research, development & demonstration."
- 2007 -- "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."
- 2008 -- "CCS technologies must be developed and made commercially available."

These prior recommendations by the Council have been reflected in growing widespread agreement that coal-based technology with CCS is the pathway to unlocking the full economic value of coal, while meeting CO_2 emission reduction goals. In 2008, the IEA identified CCS for power generation as "the single most important new technology for CO_2 savings." Researchers at the Massachusetts Institute of Technology (MIT) have stated CCS "is the critical enabling technology that would reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs" (MIT, 2007). The Clean Air Task Force (2009) has been even more direct: "No credible technical body has found that adequate CO_2 emissions are possible without widespread use of CCS."

When coupled with rapidly emerging energy efficient technologies, coal-based power generation with CCS will be part of a powerful tandem. This report utilizes the Council's previous studies as a steppingstone to show how coal-based generation with CCS provides an exciting opportunity to not only improve the quality of life for Americans but also for billions of people across the globe.

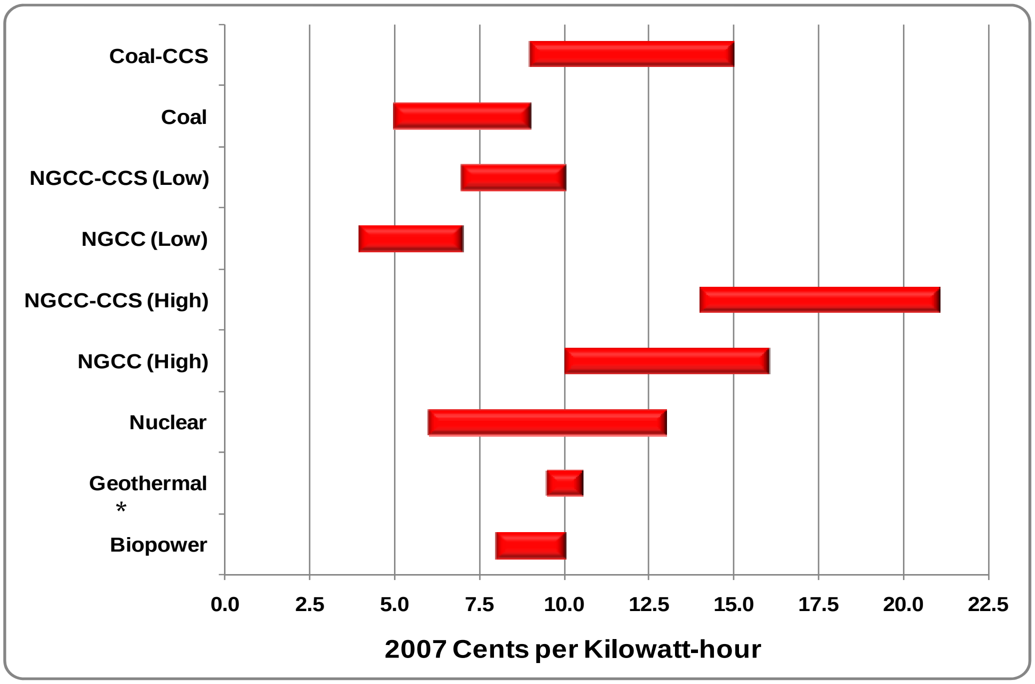
No technology has more promise in this area than coal-based generation with CCS. Natural gas supplies are questionable and prices are highly volatile. For example, in 2008 alone, wellhead prices ranged from $5.97 per thousand cubic feet (mcf) to $10.82. There is clear evidence that the increase in natural gas-fired power generation over the last decade has led not only to higher electricity prices but also to higher natural gas prices for families and businesses. In addition, there is increasing evidence that coal-based generation with CCS is a lower-price option than either nuclear or wind power (e.g., Apt et al., 2008).

More recently, in the major report *America's Energy Future* (2009), the National Research Council (NRC) assessed the levelized cost of electricity (LCOE) from new baseload and intermittent sources (see Figures 1-5 and 1-6).

The NRC clearly states <u>two crucial caveats</u>:

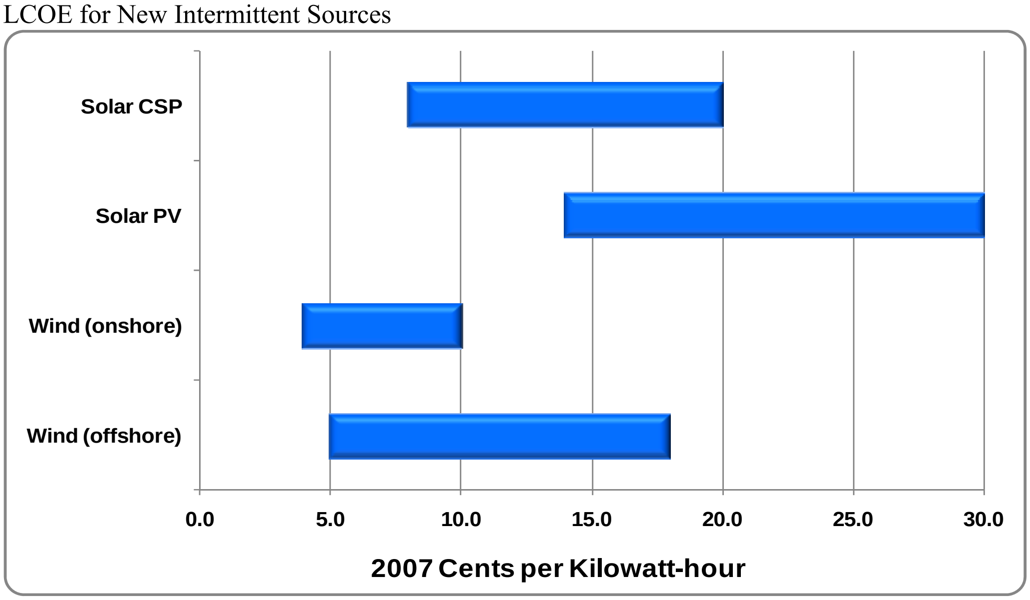
- Transmission and distribution costs are not included but are deemed as "likely to be significant" especially "when installations are located far from load centers."
- Intermittent technology costs do not account for plants that must be available to assure adequate power supplies when the intermittent source is not available.

FIGURE 1-5
LCOE from New Baseload Sources



Source: NRC (2009)
Note: Nuclear power costs include the benefit of federal loan guarantees

FIGURE 1-6
LCOE for New Intermittent Sources



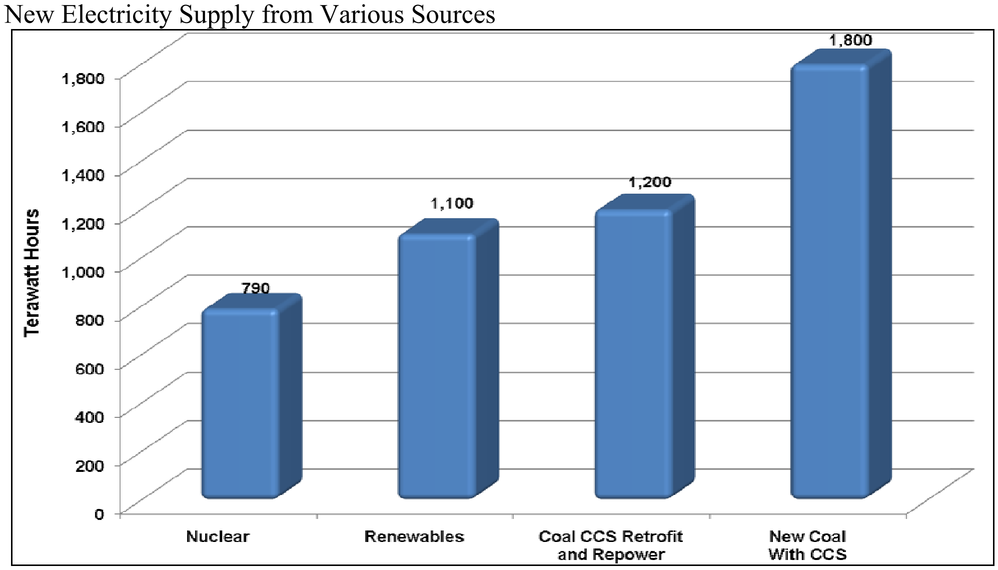
Source: NRC (2009)
Note: Wind and solar-based costs do not include significant costs for transmission, distribution, or backup generation to support intermittent nature of these resources

1.6 Coal with CCS Will Bring Significant Socioeconomic Benefits to the Next Two Generations of Americans

The combination of coal-based generation and CCS is the pathway to secure and affordable energy by advancing the three "Es" -- energy security, economic stimulus, and environmental solutions**.** Additional generating capacity will be needed in the U.S. over the coming decades for a number of reasons, but some of the most important are: 1) growing demand due to increases in population and from economic growth, 2) replacement of retiring power generating units, 3) increasing reliance on electric technologies, and 4) the increase in the use of electric and hybrid vehicles.

The NRC (see Figure 1-7) has indicated that much of the future demand for electricity in a carbon-constrained world can be met through a combination of: 1) CCS retrofitted and repowered coal-based plants and b) new coal-based generation with CCS. The NRC projected that the joint technologies could yield up to 3,000 TWh per year of new electricity sources by 2035, compared to 794 TWh for nuclear and 1,100 TWh for renewables (including hydro).

FIGURE 1-7
Potential New Electricity Supply from Various Sources



Notes:

1) 3,000 TWh from coal-based generation not likely due to competition between new plants and retrofits
2) Natural gas is deemed as potentially significant but laden with unknowns relating to price, supply and security (NRC, 2009)

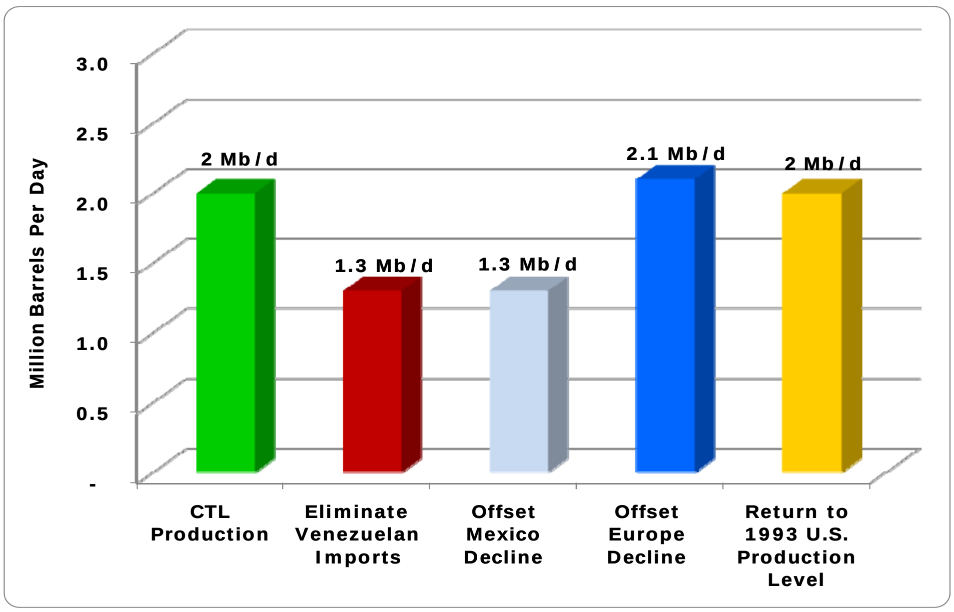
1.6.1 Enhanced Oil Recovery Using CO_2 from CCS

The security and sustainability of our nation's energy system have been perennial concerns since World War II (NRC, 2009). The U.S. needs to reduce its dependence on fragile supply chains for petroleum and may soon be faced with a similar situation for natural gas. For both national security and economic security reasons, it is important to avoid any continuation and expansion of this dangerous dependence on foreign energy supplies. The U.S. now imports about 65% of its crude oil and by 2030 the level of imports is still expected to be about 50%

(EIA, 2009). Increasingly, world oil supplies are becoming concentrated in the hands of the national oil companies. Some of these entities have questionable stability and may not have the best interests of the U.S. at heart. Hence, continued reliance on imports is likely to be both expensive and risky.

Coal-based power generation with CCS can increase supplies of oil through CO_2-based EOR. The DOE (2005) has indicated that about 2 million barrels per day of liquid fuels can be obtained through CO_2-driven EOR. Such production would have a dramatic impact on U.S. liquid fuel supplies (see Figure 1-8).

FIGURE 1-8
Benefits of an Additional Two Million Barrels a Day from CO_2-EOR



Source: Calculated from EIA (2009)

The potential of EOR to simultaneously contribute to energy supply and CO_2 emission reductions in the U.S. is substantial. A NETL (2009) analysis suggests three major benefits would accrue from using integrated "next generation" CO_2 storage and EOR:

- 119 billion barrels of additional technically recoverable domestic oil would be available and up 70 billion barrels would be economically recoverable under reasonable scenarios
- CO_2-EOR technology would create a demand for up to 13 gigatons of captured CO_2 -- generally equivalent to captured CO_2 emissions from 70 GW of coal-based power plants over a 30 year life.
- The oil produced with injection of captured CO_2 emissions is 50 to 80% "carbon-free", after accounting for the difference between the carbon content in the incremental oil produced by EOR and the volume of CO_2 stored in the reservoir.

Based on this study, the CO_2 demand from EOR alone would equal the CO_2 captured from consuming over 360 million tons of coal per year.

1.6.2 Socioeconomic Benefits of a Major Program to Construct Coal-based Generation with CCS

Over the last decade, the U.S. has suffered from economically debilitating trends. One of the key components of this problem has been the steady loss of manufacturing jobs in most states that has resulted from closures, consolidation, and out-migration of industry.

Given the increasing evidence (e.g., NRC, 2009; Apt et al., 2008) that coal-based generation with CCS is a competitive least cost, low-carbon alternative to meet the scale of energy demand, the socioeconomic benefits to the nation and to local communities from the construction of CCS facilities -- power plants and EOR production -- will open up new doors for the industrial revitalization of the U.S.

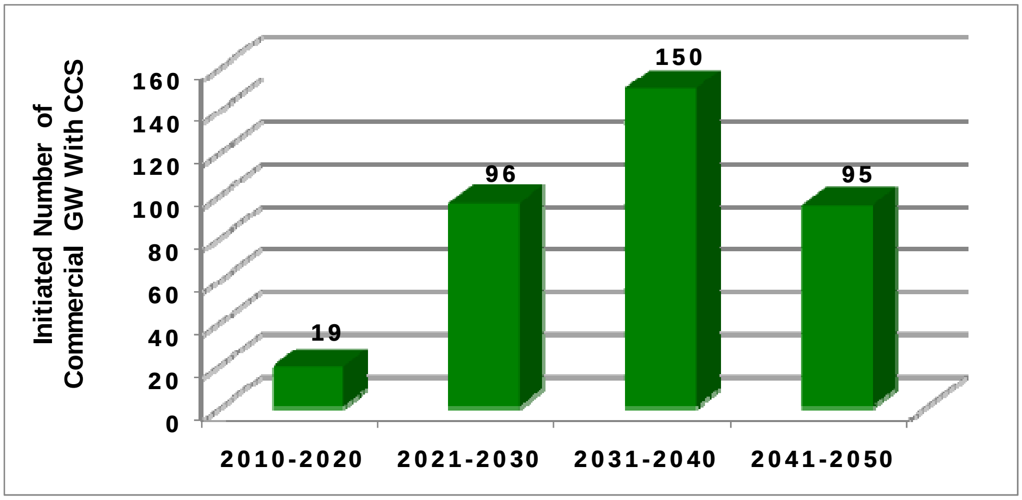
Coal-based generating facilities with CCS will be built in a broad array of individual communities scattered throughout the U.S. Local residents will help build and operate the plants. Nearby businesses will provide goods and services to the facilities. The plants will provide tax revenue, support local charities, and become embedded in the social and economic fabric of the communities.

As stated earlier, the NRC has indicated that up to 3,000 TWh per year of electricity could be produced by coal-based generation with CCS in a program that would essentially replace the existing fleet of coal-based power plants in order to reduce CO_2 emissions. The NRC specifically states:

> **"In combination, the entire existing coal power fleet could be replaced by CCS coal power .... 10 GW of demonstration fossil-fuel CCS plants could be operating by 2020 .... With similar assumptions, 5 GW per year could be added between 2020 and 2025, and a further 10–20 GW per year from 2025 ......"**

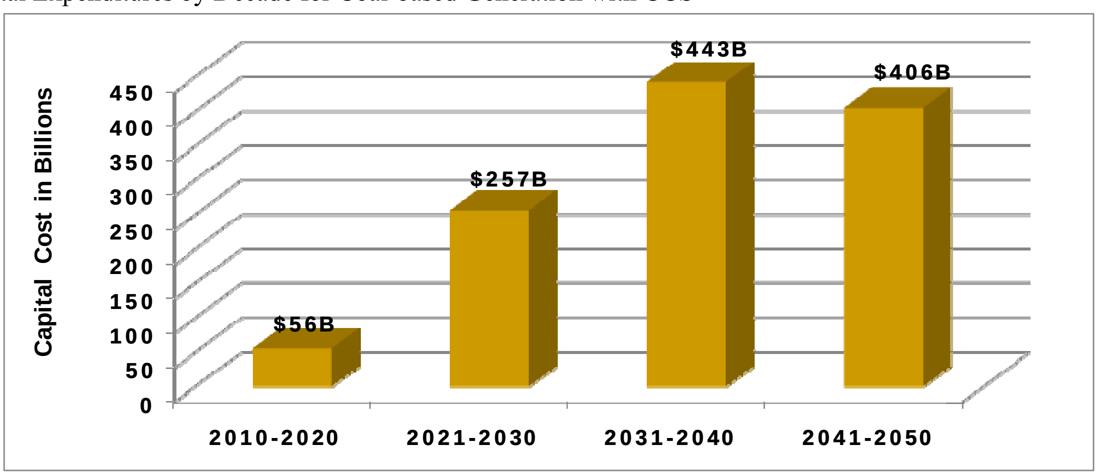
The socioeconomic benefits of the construction program outlined by the NRC would be far-reaching indeed --and nothing short of a major revitalization of the industrial sector of the U.S. Figure 1-9 shows how the NRC view of deployment of coal-based generation with CCS would fit into a decadal format. These data are compatible with the NRC conclusion that by 2050 the existing coal-based generating fleet could be replaced by coal-based generation with CCS.

FIGURE 1-9
Commercial Coal-based Generation with CCS Initiated by Decade (GW)



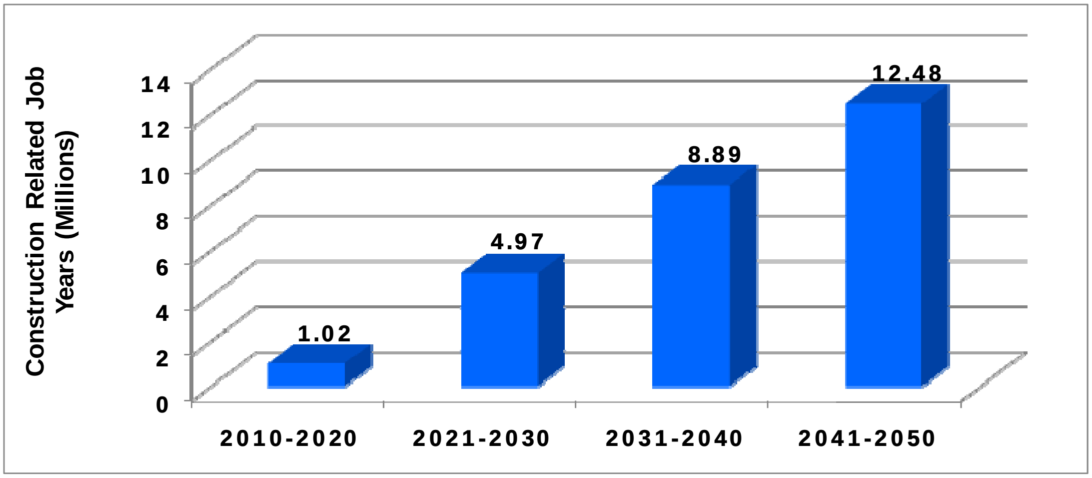
As discussed in other sections of this report, building a network of plants, pipelines and storage sites would be capital intensive, requiring a base coal utilization facility, CO_2 capture equipment, CO_2 compression, CO_2 transportation to a storage site, site acquisition, injection wells, and monitoring equipment. Once again, following the NRC assessment, this analysis assumes that 60% of all new capacity would include CCS and the remaining 40% would be retrofit or repowered with CCS. The total cost of building 360 GW of coal capacity with CCS will approach $1.2 trillion in 2007 dollars. Figure 1-10 shows how these expenditures would occur by decade.

FIGURE 1-10
Capital Expenditures by Decade for Coal-based Generation with CCS



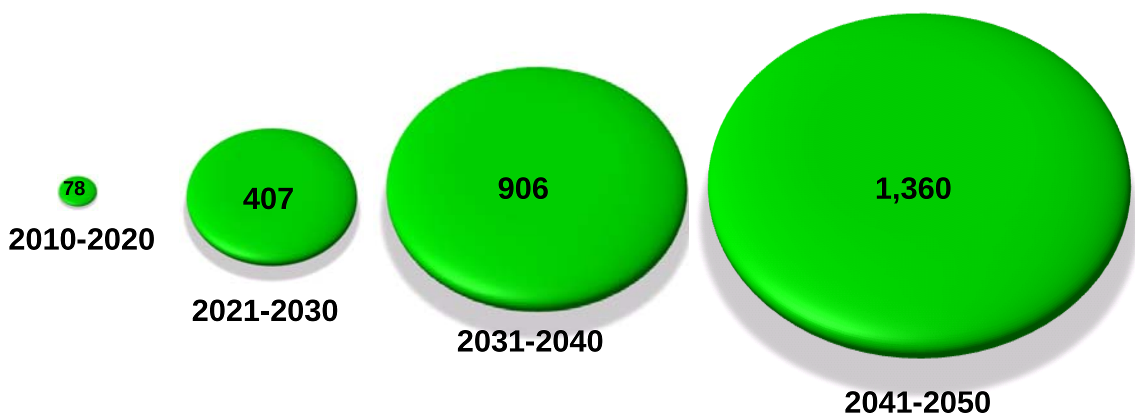
The construction of this fleet of coal-based generation with CCS will have a positive, dramatic impact on employment throughout the U.S. Using input-output multipliers estimated from a study of advanced coal-based generation with CCS conducted for the AFL-CIO by BBC Research and Consulting (2009), over a 40-year period, an annual average of over 800,000 jobs will be supported by these construction projects. As Figure 1-11 shows, the eventual impact this effort will exceed 28 million job years.

FIGURE 1-11
Construction Related Job Years by Decade for Projects with CCS



The investment effort associated with the construction activities described above will have substantial value added financial impact on the U.S. Figure 1-12 indicates GDP increases by decade. These data show:

FIGURE 1-12
GDP Increases Will Benefit Generations of Americans



Value Added in Billions of Dollars

1.6.3 Continuing Benefits for Generations of Americans

The deployment of 10 GW of demonstration projects with CCS in the 2016 period coupled with the installation of commercial-scale facilities by 2020 will initiate a continuing presence of coal-based generation with CCS for many decades. By 2030, upwards of 60 GW of coal-based generation with CCS will be operating and this will steadily increase to almost 200

GW by 2040. The operation and maintenance of these facilities will have dramatic positive impacts upon their respective local communities.

Research conducted by BBC Consulting for the AFL-CIO (2009) has clearly laid out the potential benefits in terms of jobs and income. These benefits are shown in Table 1-1.

TABLE 1-1
Economic Benefits from Operation and Maintenance of 360 GW of Advanced Coal-Based Generation Facilities with CCS

Measure	Direct Benefit	Indirect Benefit	Total Benefit
Permanent Jobs	176,400	669,600	846,000
Salaries	$22 Billion	$35 Billion	$57 Billion

Source: AFL-CIO/ BBC Research and Consulting (2009)

1.7 Time is of the Essence

There is increasing recognition that the movement toward CCS must begin immediately if the technology is to fulfill its promise as the core component of the President's goal for reducing CO_2 emissions. Today, progress throughout the world has been sporadic and often delayed, raising concerns that although these advanced technologies are generally available they are not being integrated and demonstrated as rapidly as necessary. The IEA (2009) has stressed the immediacy of the issue: **"The next 10 years will be critical for CCS development ...If these demonstration projects do not materialize in the near future, it will be impossible for CCS to make a meaningful contribution to GHG mitigation efforts by 2030."**

Similar concerns have been raised not only by Secretary Chu (2009) but also by a variety of other groups ranging from the NRC (2009) in the U.S. to the World Coal Institute (2009) to work by Great Britain's former Prime Minister Tony Blair (2009).

In many ways, the leaders of the world face a dual responsibility to both the current generation and to future generations of humanity. On the one hand, economic growth and energy development must be maintained as they are the primary means to lift billions of people out of abject poverty. On the other hand, they desire to meaningfully reduce global CO_2 emissions. Balancing this equation will be a difficult enough task. If we delay moving toward what is rightly regarded as the most promising means of mitigating CO_2emissions -- CCS -- the task will be all that much more difficult for the next generation or perhaps even impossible.

Progress will depend on a concerted policy effort and willingness to make *timely* capital investments. The word *timely* is especially stressed because the window of lowest cost opportunity will only remain open over the next decade. Therefore, it is imperative that these activities be started immediately, even though some will be expensive and not all will be successful, some may fail, prove uneconomic, or be overtaken by better technologies (NRC, 2009).

Based on Secretary Chu's statement of October 12, 2009, the goal is to have 10 large-scale CCS demonstration projects online by 2016 in order to begin widespread deployment of CCS by 2018. The failure to demonstrate the viability of these technologies during the next decade would greatly restrict options to reduce the electricity sector's CO_2 emissions over succeeding decades. The urgency of getting started on these demonstrations to clarify future deployment options cannot be overstated.

1.8 The Coal Reserves Provide the Opportunity

> **"U.S. recoverable reserves of coal are well over 200 times the current annual production of 1 billion tonnes, and additional identified resources are much larger. Thus the coal resource base is unlikely to constrain coal use for many decades to come" (National Academy of Sciences, 2009)**

1.8.1 The Past and Present are Prologue

For over 100 years, coal has been the energy workhorse for America. From the locomotives crossing the Great Plains to the steel mills of Pittsburgh to the over 600 power plants scattered across the nation, coal has been the centerpiece in providing energy, price stability, and economic growth. By mid-century, affordable and reliable coal brought American manufacturing to the center of the world's stage. Over the past three decades, coal provided 50% of the electricity to support an unprecedented economic expansion in the U.S. From 1975 to 2005, electricity consumption increased 2,135 billion kilowatt-hours -- over 110%. During the same period, the increase in coal-based generation was 1,160 billion kilowatt-hours, or more than 135%.

The prevalence of coal in maintaining a dynamic social and economic structure can be readily seen by the number of states which rely heavily on coal and represent the core of the nation's population. Over 200 million people in 34 states rely on coal for over 30% of their electric power and these states comprise about two thirds of our nation's economic activity.

In essence, coal-based electricity is an integral part of modern life, reliably powering homes, businesses, and institutions as well as facilitating transportation, communication, and public safety. Rose and Wei (2006) assessed the indirect and induced jobs that are created by the ongoing production of coal-based electric power as well as the increased family income and economic output. That research indicated that the coal industry not only provides reliable electricity at a relatively modest cost, but also is a source of steady well-paying jobs throughout the nation. Rose and Wei found that in 2015, the socioeconomic benefits of coal-based electricity will continue to reach every corner of the nation, providing almost 7 million jobs, over $350 billion in family income and more than of $1 trillion in economic output. There can be little question that coal-based electricity is the cornerstone of American socioeconomic stability.

1.8.2 Vast Resources Provide Great Opportunity

The value of coal to the U.S. economy and national security is founded on the size, quality, and accessibility of our domestic coal resources. The economic potential of coal is realized though a value chain consisting of reserve exploration, mineral rights acquisition, mine development, coal production and processing, coal transportation and use, and eventual mine closure and remediation.

Coal is the largest fossil fuel resource in the U.S. The energy content of proven recoverable coal reserves exceeds that of our petroleum and natural gas reserves by a factor of 5 to 10. Between the 1973 oil embargo and 2007, domestic natural gas production declined by 11% and oil production by 44%. Coal production, however, nearly doubled from 599 million to 1.15 billion tons.

Because of the abundance of domestic coal, and the productivity of American miners, U.S. coal has ranged from one-fourth to one-tenth the price of oil or natural gas on an equivalent energy basis. Coal is our nation's only net fossil fuel export, resulting in a positive trade balance of $2.4 billion in 2007, compared to net costs of imported natural gas and oil of $25 billion and $245 billion, respectively.

Mined in 26 states, coal represents 33% of all domestic energy production. It is used in 48 states to meet 22% of domestic energy demand; it fuels more than 50% of U.S. electricity generation, providing reliable, low-cost energy to drive our economy.

1.8.3 Abundant U.S. Coal Reserves

The U.S. coal resource is truly vast. The term "resource" refers to the total geologic extent of a mineral. In 1999, the EIA estimated the total U.S. coal resource to be 3.97 trillion short tons. Of this total resource, the EIA estimated the Demonstrated Reserve Base (DRB) to be almost 500 billion short tons in 2007. The DRB is the portion of the resource that meets certain criteria related to mining, including quality, depth, and thickness. The DRB is distributed among 31 states: 100 billion tons in ten Appalachian states; 160 billion tons in eleven Interior states; and 240 billion tons in 12 Western states. The majority (340 billion tons) of the DRB is accessible by underground mining methods and the rest (160 billion tons) by surface mining.

A portion of the DRB is accessible and economically recoverable by current mining methods, at current prices, under existing regulations. The EIA estimated in 1999 that 54% of the DRB, 265 billion tons, fell into this "estimated recoverable reserve" (ERR) category. At current production rates, the ERR would last for about 240 years. Even if production were to double, the ERR would last for more than a century. U.S. coal reserves are much greater, on a total energy basis, than the oil and gas reserves of the major oil and gas exporting nations.

1.8.4 A Vast Coal Transportation Infrastructure

Transportation is crucial to coal growth and usage. Coal is consumed in all regions of the U.S. and users depend on timely coal delivery through an efficient transportation system encompassing railroads, trucks, barges and vessels, and mine-mouth conveyor systems. In 2006, 800 million tons of coal was delivered by rail, 122 million tons by truck, 114 million tons by barge or ship, and 77 million tons by mine-mouth conveyors. Of the approximately 600 U.S. coal-based power plants, 58% are served by rail, 17% by barge or ship, 10% by truck, 12% by multiple modes of transportation (primarily rail and barge), and 3% are mine-mouth plants. All transportation modes have significant capital invested in infrastructure and equipment and will be called upon in the future to transport coal longer distances to existing and new markets. Capital investments for locomotives, freight cars, and track infrastructure will need to be put in place by rail owners to meet this growing demand. The inland waterway system can cost-effectively expand its capacity to move more cargo and facilitate the delivery of coal and other basic materials. The trucking industry will face many of the same challenges and opportunities.

1.8.5 The Potential for Growth

The National Coal Council's 2006 study concluded that the coal mining industry and transportation infrastructure can be expanded to double coal production by 2025. Even at this expanded rate, domestic coal reserves are adequate for over 100 years. Continued investment in mines and transportation infrastructure will be required within a regulatory structure that accommodates both public policy and coal production goals. Maximizing and expanding coal production will build a platform for strong new economic growth, job creation, and economic security for Americans.

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2 Timeline and Costs for Commercial-Scale CCS Deployment

Findings

- Secretary Chu (2009) laid out an aggressive timeline to have up to 10 commercial-scale CCS demonstration projects in operation by 2016 and to begin widespread and affordable deployment of CCS within 8 to 10 years. With sufficient funding and an immediate start, the timeline discussed in this report is generally consistent with the Secretary's goals.
- Commercial-scale deployment of CCS technology is contingent on a successful "Pioneer Plant" phase in which 5-7 GW of CCS capacity is built. These pioneer plants could complete four years of operation and monitoring of the CO_2 storage sites by about 2020, but funding sources to accomplish this are inadequate at present, and would require congressional action.
- Following the Pioneer Plant phase, potential owners should have sufficient confidence in CCS to build commercial-scale "Early Adopters" but they would require adequate and appropriate financial incentives (as discussed below) to justify the investment. If commercial-scale facilities could be built at the highest historical power plant capacity addition rates in the U.S., 60 GW of coal-based generating capacity (including 7 GW of Pioneer Plants) with CCS could be on line by 2030-35 and the U.S. coal-based generating fleet could be replaced with CCS-equipped capacity by 2050. This assumes an immediate start of the Pioneer Plant phase, and that non-technical issues including legal, regulatory, permitting, liability, and financial factors do not impede commercial-scale CCS deployment.
- Based on cost estimates by EPRI, the incremental capital cost (relative to new plants without CCS) for 7 GW of CCS Pioneer Plants is about $12 billion, and for the 53 GW in the Early Adopter phase is about $75 billion (all in 2007 dollars). The annual increment of the LCOE would be about $2.4 billion for the Pioneer Plant and about $15 billion for the Early Adopters. These CCS costs are competitive with the range of costs of alternative technologies proposed to meet the President's goal to "decarbonize" the electricity generating system.
- CCS projects that are dependent in the short term or long term on investment by regulated utilities, non-regulated utilities, other energy companies and private individuals must fall within reasonable risk guidelines and provide an IRR at or exceeding 20 percent per annum in order to attract investment.
- The insurance industry will not commit capital to long-term CCS projects without well-defined roles for government and an understanding of how liability is addressed, but will support the CO_2 capture and transportation phase of CCS projects, based upon current engineering/underwriting considerations.

Recommendations

- The DOE should expand the CO_2 storage tests currently being conducted under the Regional Carbon Sequestration Partnership program to larger, longer duration injection tests in a wider range of geologic and oil/gas/coal fields and fund characterizations of 5-10 potential commercial scale CO_2 storage sites. This information will be critical to making commercial investment decisions, and for developing the regulatory, permitting, legal and financial structures needed for CCS to be widely deployed.
- The DOE should design and determine the costs, timing and co-funding requirements of a "Pioneer Plant" program to achieve about 7 GW of coal-based power generation facilities integrated with CCS with the goal of achieving four years of operation and storage site monitoring by 2020. The Pioneer Plants should be geographically diverse and encompass a range of coals, CO_2 capture and electricity generating technologies, and geologic storage sites. Funding for these Pioneer Plants will require timely legislative action.
- The DOE should continue and expand research to improve the performance and reduce the cost of CCS for greenfield and retrofit applications. This should include expedited testing at pilot and larger scale of promising CO_2 capture technologies.
- Legislation or relevant agency actions at DOE and elsewhere are needed to:
  - Create an appropriate mix of medium to high levels of financial incentives to stimulate investment in CCS projects.
  - Define the responsibilities/liabilities, including federal and state regulatory cognizance associated with long-term CO_2 storage facilities. This should involve consideration of previously established models to fund or insure the liabilities associated with these facilities.
  - Encourage alternatives to long-term CO_2 storage, such as CO_2 reuse in industrial processes, which should be explored to alleviate legacy liabilities.

2.1 CCS Deployment Timeline

The purpose of this subsection is to present a model for the timing and cost of deploying CCS technology for coal-based power plants[1]. Consistent with the technology development pathways proposed by the Coal Utilization Research Council (CURC), MIT, EPRI and DOE, the timeline model assumes the need for large-scale stand-alone CO_2 storage tests and for demonstration-at-scale of integrated CCS technology as a prerequisite for power plant owners to commit to extensive commercial-scale deployment. Some CCS capacity will be built to serve the EOR and enhanced coalbed methane (ECBM) markets, but widespread deployment will require extensive storage in saline formations. The timeline model divides the necessary steps to commercial deployment into these phases:

- Stand-alone CCS storage tests in geologic formations. These are tests of CO_2 injection and post-injection monitoring, particularly in saline formations that are not necessarily integrated with an industrial source of CO_2. This in underway in Phase III of the DOE 's Regional Carbon Sequestration Partnership program, but needs to be expanded in scope

[1] This model is largely the result of work by the CURC Technical Committee.

to conduct tests in additional geographic regions, geologic formations, and at larger scale. There also is a need for detailed characterization of a number of potential commercial CCS storage sites using the suite of tools traditionally used for oil field exploration.

- Pioneer Plants (greenfield and retrofit) at least partially integrate CCS with electricity generation or some other major industrial use of coal. These would include facilities such as FutureGen and projects that include CCS which are built using incentives under the CCPI, tax credits and other financial incentives such as those proposed under various climate and energy bills currently in Congress. Pioneer Plants also would include the first plants built to provide CO_2 for EOR or ECBM recovery, for which part of the financial incentive would be oil and gas production revenue. As discussed below, 5-7 GW of equivalent CCS capacity[2] will be need to be built and operated for a period of time (approximately four years of operation and monitoring) before potential CCS system vendors and adopters will have sufficient understanding of and confidence in the technology and its costs to permit widespread deployment. The 5-7 GW of Pioneer Plant capacity is a substantial amount, representing 20-30 installations, and would be some mix of new and retrofit applications. An example of a Pioneer Plant suite that accommodates a range of technologies, coals and performance objectives was developed by the CURC Technical Committee (Table 2-1).

[2] "Equivalent CCS capacity" refers to the likelihood that to minimize technical and cost risk, plants in the Pioneer Plant phase will not treat 100% of the flue gas or syngas stream. The equivalent capacity refers to the amount of gas treated. For example, a 600 MW plant that treated half its flue gas would represent 300 MW-equivalent of CCS capacity.

TABLE 2-1
CCS Pioneer Plant Categories

Capture Location	Technology		New (N) or Retrofit (R)?	Unit size Range, MWe		Gas Treated Range, MWe equivalent		% CO_2 Capture of Gas Treated	Fuel[1]	Storage Geology	Technical Risk
Pre-combustion	IGCC	O_2	N	250	600	250	600	≥75	B/S/PC	Saline	H
Pre-combustion	IGCC	Air	N	250	600	250	600	≥75	S/L	Saline	H
Post-combustion	PC/FBC	Scrub	N	200	600	200	300	≥90	Any	Saline	M
Post-combustion	PC/FBC	Scrub	N	200	600	200	600	≥90[2]	Any	Saline	High Operational
Post-combustion	PC/FBC	Scrub	R	400	1,300	200	400	≥90	Any	Saline	M
Post-combustion	PC/FBC	Experimental	R	200	1,000	50	50	≥ 60	Any	Saline	High Technology
Oxy-combustion	PC/FBC		N	100	150	100	150	≥90	Any	Saline	M/H Ops Risk
Oxy-combustion	FBC		N	50	100	50	100	≥90	Any	Saline	M/H Ops Risk
Any								≥90	Any	Oil & Gas	M

Note 1: B = Bituminous, S=Subbituminous, L = Lignite, PC = Petroleum Coke, H = High, M= Medium

Note 2: 100% flue gas treated, fully integrated process configuration

If the Pioneer Plant phase were to begin now (late 2009), and all installations follow a typical power plant construction schedule (approximately seven years from project announcement to initial operations), some of the Pioneer Plants would achieve four years of operation by about 2020. To facilitate subsequent widespread CCS deployment, the Pioneer Plant configurations need to span a range of generating and CO_2 capture technologies, geologic storage sites, regions of the country, and coal types. Some Pioneer Plants would use CO_2 injection and storage in oil and gas fields, but a majority of these plants need to store CO_2 in saline or other geologic formations to verify the technical feasibility of this important option. All of the Pioneer Plants are assumed to continue to operate as commercial plants, and thus add to cumulative capacity over time.

- Early Adopters. Following the successful operation of a sufficient amount of Pioneer Plant capacity, plant owners would add CCS capacity on a routine basis, with the initial Early Adopter plants coming on line in the 2025 time frame. CCS would be accepted as technically proven at this point, but it likely that it will require financial assistance to justify an investment decision. CCS costs are expected to decrease over time as operators gain experience, and R&D results are incorporated into plant designs. Approximately 60 GW of cumulative capacity in the Pioneer Plant and Early Adopter phases is necessary to bring the cost of the technology down to acceptable commercial-scale levels. If the highest historical rates in the U.S. of coal-based power plant capacity addition[3] could be achieved for CCS, this implementation level could be achieved in the 2030-2035 timeframe, and perhaps a few years earlier if a significant amount of CCS coupled with enhanced oil/gas recovery is installed because of the additional revenue from oil/gas production. It is assumed that Early Adopters will anticipate success in the Pioneer Plants by planning for new CCS-equipped generation, but will not commit to construction until the Pioneer Plants have been in operation for some period of time in order to validate the costs and performance.
- Capacity Addition. Following the Early Adopter phase, CCS will be deployed based on demand, economic competition with other electricity generating technologies, and regulatory and public policy measures that facilitate or impede it. Once the Early Adopters begin operation, CCS capacity can be added at rate up to a maximum annual build rate (e.g., 10 GW/year). Some of the plants will be retrofits, limited by a maximum net retrofit capacity (e.g., 90 GW, as determined by EPRI in an analysis of existing units' sizes and ages). EOR/ECBM construction would be additional, and is assumed to have its own annual and total capacity addition limits. It is expected that costs will continue to decline with experience, and that advanced "second generation" technologies may become available in later years. In the model, this advanced technology is defined by a lower capital cost and lower LCOE, and optionally lower heat rate and higher CO_2 capture percentage.

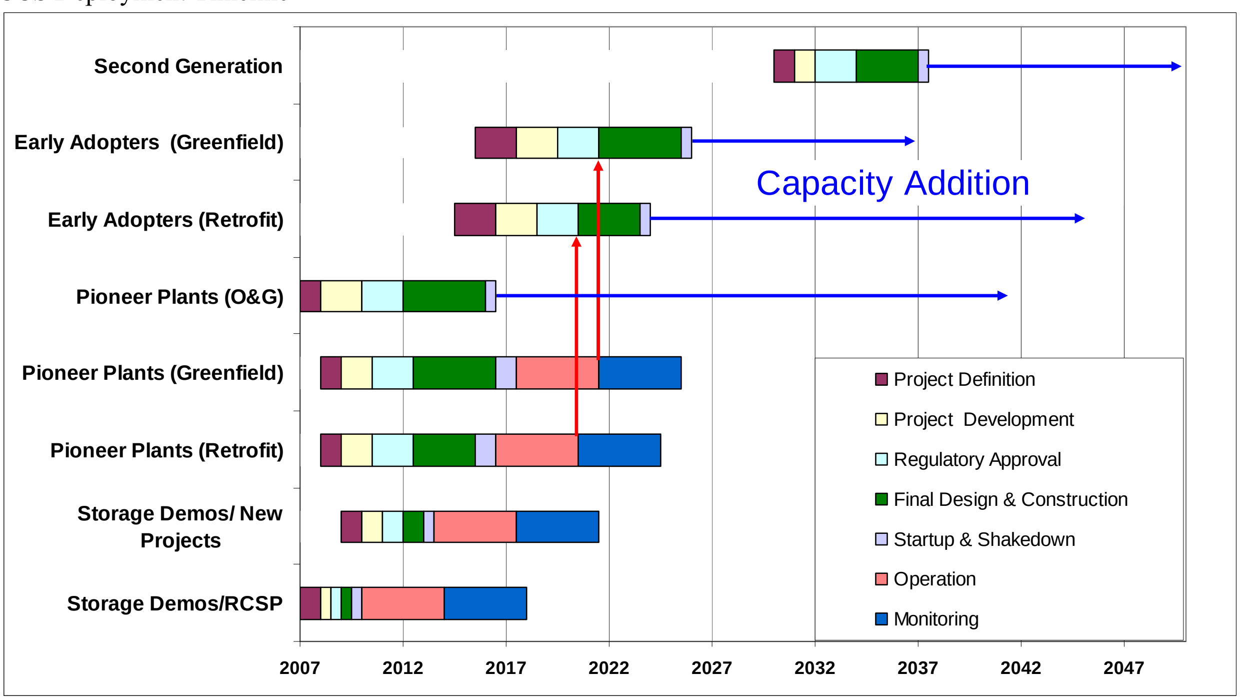
The initial deployment phases (CO_2 storage tests and Pioneer Plants) consist of individual projects each of which will proceed through a series of steps listed below:
Project Definition: Technology Assessment, Site Screening, Initial Environmental Assessment

[3] As a point of reference, in the 1970s and 1980s, the U.S. added an average of 12 GW/yr of coal-based power plant capacity, with a maximum of about 16 GW in any year. Of course, what was built at the time was much simpler (with faster permitting processes) than for a current coal-based plant with CCS.

- Project Development: DOE Selection/Contracting (if DOE-funded), Financing, Site Acquisition including CO_2 Storage Infrastructure, Access and Mineral Rights
- Environmental Approvals including National Environmental Policy Act (NEPA), Grid Access, Power Purchase Agreement, Rate Recovery, Permitting
- Site & Infrastructure Development, Design and Construction
- Startup & Shakedown
- Operation (e.g., 4 years for CO_2 storage and power plant demonstrations)
- Monitoring (e.g., 2 years for demonstrations)

The timeline is constructed by assigning start dates to each of the phases, and durations to each of the project steps within each phase. For simplicity, this model assumes that all projects in the stand-alone CO_2 storage and Pioneer Plant phases are conducted essentially in parallel and are completed successfully. This is optimistic, and results in a timeline that reflects the minimum duration required achieving a given level of commercial deployment. The model is based on the assumption that potential owners would begin the construction of CCS capacity in the Early Adopter phase only when the Pioneer Plants have been operation for some period of time (e.g., 4 years), shown in Figure 2-1 below as vertical red arrows.

FIGURE 2-1
CCS Deployment Timeline



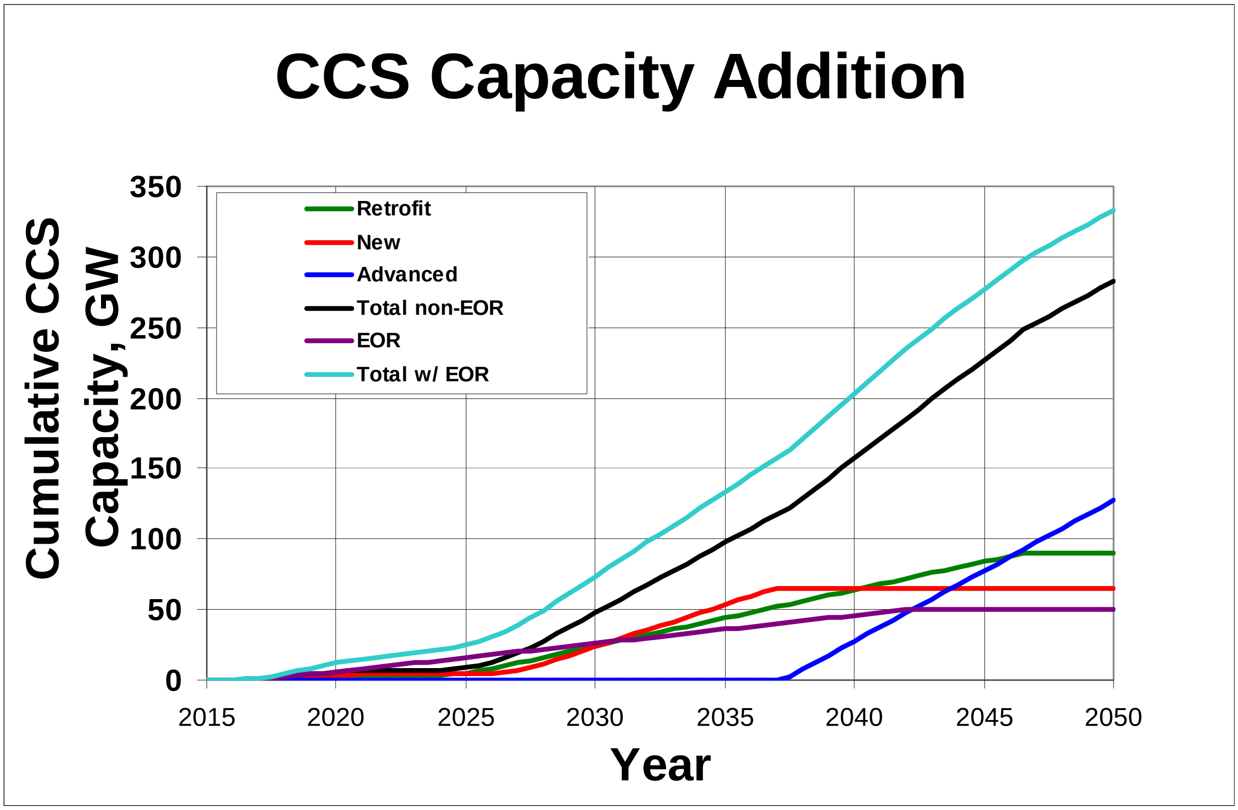
The addition rate of commercial capacity is modeled based on the start date for Early Adopters (separately for retrofit and new plants with CO_2 storage in saline formations, and EOR/ECBM projects), a rate of annual capacity addition, and an upper limit to the total capacity addition for retrofit/repowering and EOR/ECBM applications. In the model, capacity addition can ramp up linearly to the maximum rate over a number of years. These assumptions result in a cumulative capacity calculation for retrofit and new applications for saline and EOR/ECBM storage, including the Pioneer Plants projects, which are assumed to continue in operation. The input data used in the case shown here are provided in Table 2-2 below.

TABLE 2-2
CCS Timeline and Capacity Input Data

Timing and Capacity Input Data	
Pioneer Plant Capacity, GW	7
New Plant Ramp Time, Yr	3
New Plant Addition Rate, GW/yr	6
Retrofit Ramp Time, Yr	3
Retrofit Addition Rate, GW/Yr	4
Maximum Retrofit, GW	90
EOR Ramp Time, Yr	5
EOR Addition Rate, GW/yr	2
Maximum EOR, (GW)	50
Advanced Plant Ramp Time, Yr	1
Advanced Plant Addition Rate, GW/Yr	10

With these capacity and timing inputs, and the schedule shown in the timeline graph, the cumulative CCS capacity over time is determined, as shown in Figure 2-2 below. The graph shows greenfield and retrofit capacity in the Pioneer Plant, and Early Adopter phases, and plots EOR capacity separately. The results suggest that with an immediate start to the Pioneer Plant phase, 60 GW of Pioneer and Early Adopter capacity could be in operation by about 2030, and that the existing 300 GW of coal-based capacity in the U.S. could be replaced by 2050. However, it is important to note that the model attempts to define a maximum rate of CCS capacity addition over time, based on the timing of the Pioneer Plant phase, and subsequent annual capacity addition limits. This supposes that there is policy in place to fund the Pioneer Plant phase. Although there are programs in existence, such as FutureGen and the CCPI programs that are conceptually aligned with the Pioneer Plant phase, they are not funded at the level it would take to build 5-7 GW of CCS-equivalent capacity. Nor does this analysis explicitly take account of factors like financing, regulatory, permitting, legal, liability, land use, and infrastructure development which must be in place to allow for the kind of rapid expansion of CCS capacity modeled in the Early Adopter and later stages. In effect, the analysis assumes that these factors are dealt with in a timely manner so that they do not impede the ability to reach and sustain a maximum annual CCS build rate.

FIGURE 2-2
Cumulative CCS Capacity Over Time



2.2 CCS Deployment Cost: Pioneer Plant and Early Adopter Phases

The cost of CCS includes the capital expenses for the base coal utilization facility (most likely for power generation), CO_2 capture equipment, CO_2 compression, CO_2 transportation to a storage site, site acquisition, injection wells, and monitoring equipment. For a retrofit application, the capital cost of the base facility effectively may be zero (i.e., the original capital cost has been fully amortized), but an additional capital expense is assumed to be incurred (in addition to retrofitting costs) to replace the generating capacity lost because of the derating of the retrofit unit. The ongoing expenses include fuel and non-fuel operations and maintenance (O&M) costs for the coal utilization facility, CO_2 transportation system and the storage site. The LCOE is the sum of the O&M expenses and the recovery of capital. A plant owner may look at CO_2 transportation and storage as an operating expense rather than a capital expense, if it contracts with another party to take the CO_2 at the plant gate.

Various organizations have estimated the capital and operating costs of CCS. A particularly useful analysis was done by EPRI under its CoalFleet program[4]. EPRI analyzed various CO_2 capture scenarios based on a variety of electricity generating technologies (pre- and post-

[4] See, for example, Holt and Booras, "Review of New CoalFleet Engineering-Economic Evaluations", Tulsa, OK 4/16/2008. Updated data from EPRI, February 2009 were subsequently incorporated in the model.

combustion) in greenfield and retrofit applications, for bituminous and subbituminous coals. The average capital cost over the range of cases EPRI considers is approximately $3,900/kilowatt (kW)[5] for electricity generation and CO_2 capture, and a LCOE of $105/megawatt-hour (MWh) (including $10/tonne CO_2 for transportation and costs) for a new coal-based generating plant equipped with CCS. This includes a 10% first-of-a-kind contingency. The EPRI analysis of the retrofit of an existing pulverized coal (PC) unit results in a capital cost of about $2,000/kW and LCOE of about $76/MWh (both costs include the cost of new CCS-equipped replacement power). All costs are in 2007 dollars.

Determining the incremental cost of CCS requires a baseline. A useful approach is to assume that existing coal-based plants would be retired over time, and replaced and augmented with new capacity. If this were to happen absent GHG regulation, plant owners would be expected to build the non-CCS generating technology with the lowest LCOE, which in EPRI's analysis is SCPC technology. The corresponding assumption is that if GHG legislation were enacted, owners would replace or retrofit existing capacity over time with CCS-equipped units. In EPRI's analysis, these might be based on IGCC or SCPC, with the economic choice depending on the coal and technology. The results show that the capital costs and LCOEs are comparable for the two technology classes if they incorporate CCS; it is therefore reasonable to use the average of EPRI's IGCC/CCS and SCPC/CCS values compared to supercritical PC (SCPC) w/o CCS. Average values from EPRI's analysis[4] are shown in Table 2-3 below (constant 2007 dollars). The incremental cost of the retrofit CCS system is relative to a fully amortized existing plant with a busbar power cost of $20/MWh.

TABLE 2-3
CCS Capital Cost and LCOE

	New SCPC w/o CCS	**New SCPC w/CCS**	**SCPC w/Retrofit CCS***
Capital, $/kW	$ 2,450	$ 3,910	$ 2,040
LCOE, $/MWh	$ 62	$ 105	$ 76

* Includes cost of new CCS-equipped replacement power

Using these values, it is possible to calculate the total incremental capital cost of the Pioneer Plant and Early Adopter phases, and the annual incremental LCOE. This is based on a Pioneer Plant phase consisting of 7 GW of capacity (4 GW of new build and 3 GW of retrofit), and the Early Adopter phase consisting of 53 GW (27 GW of new build and 26 GW of retrofit). As shown in Table 2-4 below, the incremental capital cost for 7 GW of capacity in the Pioneer Plant phase is about $12 billion, and for the 53 GW in the Early Adopter phase it is $75 billion. The annual incremental LCOE cost in the Pioneer Plant phase is $2.4 billion (of which over half is capital recovery), and in the Early Adopter Phase, when all capacity is on line, it is $15 billion.

5 For more information, see, for example: George Booras, "Economic Assessment of Advanced Coal-Based Power Plants with CO_2 Capture", MIT Carbon Sequestration Forum IX: Advancing CO_2 Capture Cambridge, MA September 16, 2008. EPRI did not estimate capital or operating costs for CO_2 transport and storage, but included $10/MWh in the LCOE to account for it.

TABLE 2-4
LCOE and Capital Cost Compared to New Build w/o CCS

LCOE, Pioneer Plants vs. New Build w/o CCS						
	Plant Capacity, GW	**Annual generation, MWh/yr**	**Pioneer Plant LCOE, $/MWh**	**New Build LCOE, $/MWh**	**LCOE Difference, $/MWh**	**Annual Cost Difference, $ Billion**
New	4	28,032,000	105	62	43	1.21
Retrofit	3	21,024,000	76	20	56	1.18
Total						2.39

LCOE, Early Adopter vs. New Build w/oCCS						
	Plant Capacity, GW	**Annual generation, MWh/yr**	**Early Adopter LCOE, $/MWh**	**New Build LCOE, $/MWh**	**LCOE Difference, $/MWh**	**Annual Cost Difference, $ Billion**
New	27	315,360,000	94.5	62	32.5	6.15
Retrofit	26	126,144,000	68.4	20	48.4	8.82
Total						14.97
Costs are in constant 2007 dollars.						
The "new build" is assumed to be a SCPC unit without CCS.						

Capital Cost, Pioneer Plant vs. New Build w/o CCS						
	Plant Capacity, GW	**kW**	**Pioneer Plant Capital $/kW**	**New Capital Cost $/kW**	**Difference in Capital Cost $/kW**	**Difference in Capital Cost $ Billion**
New	4	400,0000	3,910	2,450	1,460	5.84
Retrofit	3	300,0000	2,000	0	2,000	6.0
Total						11.84

Capital Cost, Early Adopter vs. New Build w/o CCS						
	Plant Capacity, GW	**kW**	**Early Adopter Capital Cost ($/kW)**	**New SCPC Capital Cost ($/kW)**	**Difference in Capital Cost ($/kW)**	**Difference in Capital Cost ($)**
New	27	27,000,000	3,510	2,450	1,060	28.6
Retrofit	26	26,000,000	1,800	0	1,800	46.8
Total						75.4

One way to put these values into context is to calculate the cost of avoided CO_2 based on the incremental LCOE and amount of CO_2 captured. In the cases presented here, 85% CO_2

capture was assumed. This results in a CO_2-avoided cost of about $85/tonne for retrofit applications and about $65/tonne for greenfield installations. Although the incremental LCOE from a retrofit unit is higher than for a greenfield unit, the absolute COE is lower for the retrofit unit because of the amortized capital value of the plant that was retrofitted. These costs are expected to decrease over time through a learning experience and the possible incorporation of advanced technology.

These costs are substantially higher than the current average COE from coal-based generation or other sources in the U. S. However, the cost of "decarbonizing" the electricity generation system is going to be high, regardless of the options chosen. A recent report from the National Research Council[6] compared the LCOE of new electricity sources. The results (see Table 2-5) show a high degree of uncertainty. Note that "Coal w/CCS" falls well into the ranges of "low-carbon" options.

TABLE 2-5
LCOE for Low-Carbon Electricity Generation Sources[6]

Energy Source	LCOE Cost Range, $/MWh
Biopower	80-100
Geothermal	100
Nuclear	60-130
Natural Gas Combined Cycle w/CCS	70-210
Coal w/ CCS	90-150
Wind (offshore)	50-180
Wind (onshore)	40-100
Solar Photovoltaic	140-300
Solar Concentrating Solar Power	80-200

Given the current knowledge, the LCOE from any of these technologies is substantially higher than the LCOE from the current generating fleet. The average busbar cost of electricity over the range of technologies in the table above is over $100/MWh. For comparison, in a recent presentation EPRI used a value of $20/MWh for the busbar power cost from existing coal-based power plants[4]. Data compiled by FERC and reported by EIA show that retail prices in highly coal-reliant states (e.g., West Virginia and Kentucky) are in the range of $40/MWh, with wholesale prices of $25-40/ MWh[7]. A query of the Ventyx Energy Velocity Power Plant Cost Model provides a value of $30/MWh for busbar electricity production costs in June 2009 for all coal-based generating plants in the U.S. with capacity factors greater than 25%.

6 "Summary Edition, America's Energy Future: Technology and Transformation," Committee on America's Energy Future, National Research Council, Prepublication Copy, August 2009.

7 http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html

In addition, various factors make it difficult to compare costs from different generating sources in a simple manner. For example, the National Research Council report cited above notes that the low end of the LCOE range for nuclear plants (as shown in Table 2-5) would be for a few units receiving federal subsidies; natural gas price volatility results in a large range of estimated costs and corresponding uncertainty; biopower can provide only limited new supplies of electricity; wind power can have large electrical-transmission and distribution costs because power generation sources are spatially distributed; and most renewable sources provide intermittent power, which reduces their value in the electricity system. Nevertheless, it is clear that CCS-equipped coal-based generation plants are expected to be competitive with other sources, with the advantages of a reliable fuel supply and the ability to meet the large base-load demand now satisfied by conventional coal-based facilities.

2.3 Ranges of Acceptable Risk and Risk Management for Private Investment, and Private and Public Incentives

2.3.1 Incentives – Financial Tools to Accelerate Deployment

It is critical that future investments in coal-based power generation be attractive not only to government entities that might provide financial subsidies, but also to private investors. This would include companies strategically motivated to invest in coal-based power generation projects (i.e., which include CCS) such as regulated and non-regulated utilities, oil and gas and other energy-related companies. Moreover, it is important that the projects be attractive to individual and institutional investors, which in turn will invest in these energy companies.

There are three primary elements to the investment evaluation in coal-based generation projects:

1. Risk analysis by type of risk, evaluation and mitigation
2. Estimate of return on the capital to be invested in the project
3. Assessment of incentives; valuation and availability

Today, the appetite for risk is low and investment analysis is very conservative, exacerbated by the extreme downturn in the global economy. This dynamic is compounded when considering coal-based generation investments, due to the amorphous nature of the risk and return analysis.

<u>Return on Investment:</u> Regulated electric utilities are considered to be one of the most prolific private investors. Their characteristics are:

- The required rate of return is the same for all projects (currently 10-11% on equity).
- The public utility commission effectively dictates the return allowed.
- The utility must be assured by regulators that sufficient rates will be allowed to provide the minimum internal rate of return (IRR).
- They must be able to pass investment costs to the consumers via rates or subsidize project costs with public sector funding, principally at the federal level.

- If the rate of return looks feasible, then there is scrutiny of risk and whether the risk is within their tolerance profile.
- State legislation may be necessary to allow funding of advanced coal-based generation projects.

There must be an adequate level of "Pioneer Plant" capacity operating by the early 2020s (as discussed above) to give investors confidence in the performance and cost of the technology. Therefore, projects need to be approved, permitted and under construction within the next few years.

Secondly, the oil and gas industry represents a logical sector to invest in coal-based generation technologies. With oil and gas depleting at an ever increasing rate, many traditional oil and gas companies are searching for logical alternative energy investments. They, along with non-regulated utilities, would likely require an IRR of 20% (more detail appears in Table 2-6.

TABLE 2-6
Rate of Return Required By Type of Investor

Returns / Yield	Acceptable Range
Private Investor Non-Utility e.g. Oil and Gas Sector	
Present Value (PV) of operating income to investment	1.3 x operating income x initial investment
Net Present Value (NPV) of discounted cash flows	Positive NPV when discounted at 15 % with cost of capital at 15 %
IRR 15 % above low risk equity, total 20 % IRR. Assume life long 3% inflation and no risk government securities above inflation i.e., 5-6% bonds. Also assume no terminal value.	20 %
Regulated Utility Investor	Regulated utility investors IRR ≥11 %
Unregulated Utility Investor	IRR of 22 - 25% since the risk is much higher than for the regulated utility due to market conditions

PV = present value

<u>Risk Tolerance:</u> Every entity, utility or other industry sector will very carefully assess risk of implementing new technologies. Due to the historical amorphous nature of any emerging technology, overlaid by uncertain regulatory and political risk, coal-based generation technologies are perceived to carry considerable risk. This subsection provides a break down of risk by category and analyzes how each category may be assessed to determine what degree of risk is tolerable (see Table 2-7). Risk factors minimally include the following[8]:

- **Human** - from individuals or organizations, illness, death, etc.
- **Operational** - from disruption to supplies and operations, loss of access to essential assets, failures in distribution, etc.

8 MindTools TM Analysis and Risk Management, http://www.mindtools.com/pages/article/newTMC_07.htm

- **Reputational** - from loss of business partner or employee confidence, or damage to reputation in the market.
- **Project** - risks of cost over-runs, jobs taking too long, of insufficient product or service quality, etc.
- **Financial** - from business failure, stock market, interest rates, unemployment, etc.
- **Technical** - from advances in technology, technical failure, etc.
- **Natural** - threats from weather, natural disaster, accident, disease, etc.
- **Political** - from changes in tax regimes, public opinion, government policy, foreign influence, etc.
- **Others** - Porter's Five Forces analysis may help identify other risks.

TABLE 2-7
CCS Project Risks by Category

Risks Types	Measurement	Acceptable Range	Rating Low to High
Human	Projected injuries compared to OSHA average for relevant sector	10 – 20% lower	Low
Operational	Employment of proven technologies, analysis of integrated system uptime probability	90 – 94% uptime based on availability. Non utility investors may expect an uptime higher than utilities.	High
Reputational	Monitor public opinion; start with baseline at startup based on survey.	Deterioration in rating of no more than 10% at the end three years	High
Project cost and schedule	If a company uses Construction Industry Institute processes. Over/under estimates budget and schedule	5 % over to 10 % under	High
Financial	IRR	Non utility average 20%	High
		Regulated Utility average ≥11% IRR	
		Non regulated utility 22 – 25% IRR	
	PV of discounted cash flows	Positive NPV when PV is discounted at 15% with cost of capital at 15%	
Technical	Discrete segments of process weighted, probability analysis	95% chance of success; no major delays in system start up; 90% plus uptime based on availability	High
Natural	E.g., EPA, and State Air and Water Quality agencies parameters	Over 0%, under 20%	High
Political	Identify key success factors in political arena and analyze probability of achievement	Average 85% probability of achievement	High

2.3.2 Public Sector Financing/Incentives for CCS

Until carbon prices (or taxes) rise to a level that justifies private investment, some amount and kind of financial incentives will be needed for private investors to build and operate the early CCS facilities. The magnitude of that investment can be gauged by examining the capital and operating costs estimated for the Pioneer Plant and Early Adopter phases described above. In addition, there will be a need for R&D funding to improve the performance and cost of CCS. CURC and EPRI have estimated the R&D costs as approximately $5 billion over the next 15 years[9].

Various financial instruments and non-financial incentives, as discussed below and listed in Table 2-8, are potentially available from the government. A combination of incentives will likely be needed, because different segments of the industry have different abilities to use these financial mechanisms. For example, municipal utilities, which do not pay income tax, would not be able to use tax credits. Large investor-owned utilities may have less need for loan guarantees. For individual projects, a combination of incentives may be appropriate. The most important characteristic of any combination of incentives is that the amount is adequate to offset the difference between the incremental cost of CCS and the value of CO_2 allowances (if this is done under a cap-and-trade program) or carbon tax.

- Annual appropriations currently are being used by the federal government to support DOE CCS R&D and demonstration projects (e.g., CCPI and FutureGen). These direct-grant programs provide funds to the recipient in a relatively simple manner, but have several drawbacks. Their future funding (unless appropriated in advance) is uncertain because of the vagaries of the Congressional budget process. The projects themselves are subject to DOE procurement and acquisition regulations including lengthy NEPA-approval processes, and reporting and intellectual property requirements.
- A self-imposed fee on electric utilities (i.e., a wires charge) to fund early CCS deployment (essentially the Pioneer Plant phase in the timeline) was authored by Rep. Rick Boucher (D-VA) and is included in H.R. 2454. This approach avoids the uncertainty of the appropriations process while retaining the attractive features of the direct grant program. It also may avoid some of the administrative requirements of the DOE programs. However it does add to the electricity costs of consumers and may require state regulatory action to allow utilities to include the costs in their rates.
- Investment tax credits (ITC) support capital investment and can facilitate financing. The process to receive the tax credit may be relatively fast, avoiding appropriations and procurement concerns, but not if the credits are subject to allocation, which is the case with the tax credits in EPACT of 2005. However, the qualifying performance criteria, particularly for nascent technology like CCS, must be flexible enough so that the full, intended benefit of the tax credit is achieved. As noted above, tax credits do not benefit not-for-profit utilities and rural cooperatives, although an analogous "tax credit bond" could provide a similar incentive for these entities.
- Production tax credits, CO_2 storage credits or bonus allowances have advantages and disadvantages similar to those of ITCs. As with ITCs, the amount and duration of the credit must be sufficient to encourage sufficient private investment. One disadvantage of production-based credits is that funding is not available or guaranteed until the facility

[9] The CURC/EPRI roadmap can be accessed at http://www.coal.org/roadmap/index.asp.

begins operation, and the investor may incur a substantial risk if the ITC is tied to a particular performance standard (e.g., percentage of CO_2 captured). In the case of bonus allowances, there is additional uncertainty in the value of the credit because the future price of allowances is unknown, unless the credit value is linked to some price collar or schedule.

- Federal Loan Guarantees or financing by a federal bank can help reduce the cost of capital and buy down the technical risk for Early Adopters. It may be particularly attractive for entities in the power sector with lower credit ratings. However, the application process can be complicated and lengthy, particularly if the federal agency or agencies are required to allocate limited loan guarantee amounts to competing recipients.
- Direct subsidies, either based on production or covering a percentage of capital and operating costs, would be paid to facilities that meet specified performance requirements on a fixed schedule. The funding should not be subject to annual appropriations, in order to provide certainty to the private investor. The program could be structured to provide higher incentives to Early Adopters, and the payment rate could vary depending on performance (e.g., percentage CO_2 captured) to provide additional incentives for technical risk. As with the other incentives, the stringency of the performance standards and the amount and duration of the subsidy must be adequate to secure private investment.

TABLE 2-8
Incentives to Consider for Private Investors

Incentives: State and Federal[10]	**State and/or Federal S/F**	**Previously Employed**	**Attractiveness low to high**
Guaranteed loans	S/F	X	H
Bond funding	S	X	M
Full cost recovery on projects from customers, e.g., regulated utility, i.e., securitization	S	X	H
Waiver of certain PUC rules	S	X	L
Financial assistance i.e., Office Energy Management & Conservation	S	X	L
Tax credits	S/F	X	H
Qualified tax exemption	S/F	X	M
Property tax abatement	S	X	H
Specific project incentives i.e., Mesaba Energy proposed IGCC project, Taconite, MN	S/F	X	L
Govt. minority share partner	S	X	L
Coal development impact trust fund	S	X	L
Tax credit $/ton local coal burned	S	X	H

[10] State Incentives for Advanced Coal Projects, prepared by CURC, 2006

Incentives: State and Federal[10]	State and/or Federal S/F	Previously Employed	Attractiveness low to high
Permit syngas producers exemption from utility regulations	S/F	X	L
Require Railroad Commission to own CO_2 captured by certain facilities	S	?	L
Sales and use tax exemption equipment and materials for construction.	S	X	M
Environmental agency deferral air/water quality standards.	S/F	X	M
Guaranteed pricing tied to index	S	X	L
Bonus allowances (of the kind proposed in various legislation)	F	X	H
Direct grants (e.g., the Boucher bill or DOE CCPI program) as categories of incentives	F	X	H

2.3.3 Insurance/Risk Management Role in CCS

Like any other project backed by the public/private sector, no individual project will move forward without all financial, liability, and environmental risks identified, measured and dealt with through prudent risk management practices and/or risk transfer mechanisms. Insurance itself will not guarantee that CO_2 will not be released into the atmosphere. It will deal with the public liability impacts of premises/operations associated with these sites. Success will require some combination of public and private resources that will guarantee the long-term viability of CCS locations.

The CCS lifecycle presents a different set of risk management issues and potential solutions depending upon the stage in the cycle. Different risk transfer mechanisms or combination thereof are appropriate throughout the lifecycle. The lifecycles are categorized as follows:

- CO_2 capture
- Transportation
- Storage (i.e., injection and long-term storage)

The Capture and Transport cycles can create risk to public and private property. However, these risks are managed through existing risk management/risk transfer mechanisms that are common to many industrial applications. Current underwriting standards have evaluated, priced and transferred these risks. Understanding that established operators will undertake these projects, these risks are now managed through a combination of risk retention and transfer (bonds, insurance, self-insurance, etc.) that are common to their existing operations.

The insurance industry will be a silent partner to the public sector in evaluating and supporting which projects will move forward into full-scale commercial development. The following insurance companies have expressed a willingness and ability to commit the resources necessary to support these projects:

- Zurich
- Chubb
- Arch
- Chartis (AIG)
- Lloyds

There will be stringent review of management, engineering, environmental, financial and risk management plans. Only those facilities exhibiting “best-of-class” operations will be able to obtain the required insurance support.

It is the Storage phase that presents many unique and sometimes immeasurable and uninsurable risks. The real role of government (the long-term liability of storage) is not yet defined or legislated. Various approaches to transferring liability for long-term storage from the private to the public sector have been proposed, but none has advanced. Potential investors are waiting for the government to act. Which agency or agencies (state and federal) will regulate these projects is not yet finalized. More importantly, the financial consequences of unplanned releases of stored CO_2 and the responsibility for long-term stewardship of CO_2 facilities have not yet been determined. It will be difficult for private equity to invest capital with unknown long-term consequences.

To date, there has not been a loss associated with CCS technology. It can be argued that the incremental release or leakage from a permanent CO_2 storage facility is an irrelevant event from a public liability prospective and is an uninsurable event. Even though the “damages” are not measurable from a liability standpoint, they could come in the form of fines and penalties, loss of operating permits, forfeiture of bonds and the shutdown of the facility. These types of damages are secured through financial mechanisms such as bonds and/or letters of credit. Like other financial guarantees of a long-term nature, only the strongest, most well-capitalized organizations will be able to satisfy the requirements and be able to post the required bonds or financial instruments to secure the liability, unless government at some time and some manner assumes the liability.

The long-term stewardship from closure/post closure requires a public/private framework as the key to the long-term success of the CCS facility. There needs to one oversight authority to manage the conflicting jurisdictions and laws governing this type of facility. There are several good models on which to rely, including the following:

- Price-Anderson Nuclear Industries Indemnity Act (1957)
- The National Flood Insurance Act (1968)
- Oil Pollution Act (1990)

This may involve the establishment of a quasi public/private authority that vests the responsibility for these projects from siting to long-term management of the facility once past the post-closure phase. This can include the establishment of trust funds and other financial responsibility guidelines similar to the mandates in the Acts listed above.

In Section 5, the subsection on “Beneficial Uses of CO_2” outlines a suite of alternatives to geologic storage. These methods create a completely different risk profile and can eliminate the concern created by the legacy issues of long-term storage. The issues then become “operational” issues similar to industrial applications and can be handled within the context of existing risk management, insurance underwriting mechanisms.

3 Retrofitting the Existing Coal-based Generating Fleet to Increase Efficiency and Decrease CO_2 Emissions

Findings

- Commercially-available technologies could be retrofitted today to a large portion of existing coal-based power plants; increasing their efficiency by only 1-2% would result in near-term reductions in CO_2 emissions of 20-40 million tons per year. Retrofitting combinations of these technologies on existing plants would provide significant additional reductions.
- Until high CO_2 removal rate and CO_2 storage technologies are commercially available and proven at large scale, partial CO_2 capture (i.e. 40-60%) could provide additional near-term reductions in CO_2 emissions from the existing coal-based generating fleet. This could be accomplished by the installation of high removal rate CO_2 capture systems on a slipstream of each plant's exhaust gases.
- Together, the combination of high efficiency retrofits and partial CO_2 capture would result in significant near-term reductions in CO_2 emissions from the existing coal-based generating fleet.
- There is a need for economic incentives and regulatory changes that will encourage electric utilities to undertake these large capital expenditures solely for the purpose of meeting the President's goal of reducing CO_2 emissions.

Recommendations

- In order to achieve the President's goal of near-term reductions in CO_2 emissions from the existing coal-based generating fleet, the Council recommends that Congress and the DOE provide economic incentives to encourage the retrofit of efficiency-improving technologies and/or partial CO_2 capture technologies to the existing coal-based generating fleet.

3.1 Introduction

Prior sections of this report focus on new technologies that can be applied to new coal-based power generation units in order to minimize their CO_2 emissions. According to the EIA's 2009 Annual Energy Outlook, coal-based capacity additions through 2025 are expected to be about 8 GW. Significant increases in CO_2 emissions can be avoided using these new technologies.

However, the existing coal-based generation fleet includes about 315 GW of capacity and emits approximately 2 billion tons/year of CO_2. While the CO_2 capture technologies described previously in this report are intended to be applied to large, commercial-scale units, the existing fleet represents the greatest opportunities to achieve the most significant near-term reductions in nationwide CO_2 emissions. These reductions can be accomplished by retrofitting the following combinations of technologies:

- Technologies that increase the efficiency of power generation, thereby reducing the amount of coal burned for the same amount of generation, resulting in reduced emissions of CO_2; and
- CO_2 capture technologies which would treat a slipstream of the flue gas.

Together, this combination of technologies can provide for a significant, near-term reduction in CO_2 emissions from the existing coal-based power generation fleet. Each of these technology areas is described below.

3.2 Retrofit Technologies for Increasing Generation Efficiency and Decreasing CO_2 Emissions

3.2.1 Reducing CO_2 Emissions from Existing Units

Prior to the commercial availability of CCS technologies at large, commercial scale, the best option for existing plants to reduce CO_2 emissions is through the retrofit of efficiency-increasing technologies. While new, higher efficiency coal-based power plants offer lower CO_2 emissions per unit of electricity generated, complete replacement of existing generating units is not economically feasible because their lifetimes are typically greater than 40 years. Therefore, replacement costs would be prohibitive. Also, less efficient subcritical PC units play a key role in meeting base load electricity demand, and taking them out of service for replacement would have significant impacts on the availability and reliability of electricity nationwide.

There are approximately 315 GW of coal-based generating capacity in the U.S., provided by 1,100 generating units. They are of various types, sizes, and ages. Fortunately, there are many technical methods to gain modest efficiency improvements in many of these units. These methods range from combustion improvements to enhanced heat transfer in boiler components to moderate rebuilds of specific boiler sections. They involve modest capital expenditures, incurrence of variable expense, or both.

The technical modifications that have potential to increase plant efficiency are discussed in the following section. These options are commercially available for small and large-sized generating units, unlike CCS technologies.

3.2.1.1 Efficiency Improvements

Improved efficiency reduces CO_2 emissions by reducing the amount of fuel required to generate a given amount of electricity. A two percentage point gain in efficiency provides a reduction in fuel use of about 5% and a similar reduction in CO_2 emissions. Improved efficiency can also provide similar reductions of other pollutants regulated by the Clean Air Act, and reduce water consumption.

While not as dramatic in scale as building new higher efficiency power plants, small gains can be made across the fleet of existing plants through component upgrades, as well as O&M

activities. These improvements will be very specific to a given unit, but generally can lead to improvements resulting in reduced CO_2 emission rates. As an example, the average generation efficiency in 2005 for fossil-fuel steam generating power plants was 33%. If the national average heat rate (a measure of efficiency) was improved by 100 British thermal units (Btu)/kWh (the lower, the better, for heat rate), CO_2 intensity would be reduced by 1%, with a 20 million ton/year reduction in CO_2 emissions.

Improvements in efficiency are available with commercially available technology and are segregated into several performance areas of a coal-based boiler: combusting the coal, transferring heat to the steam, reduction of gas temperature leaving the boiler, facilitating steam turbine performance, and auxiliary equipment efficiency. All the improvement areas stated above for the existing coal-based fleet are for maintaining initial design performance of all areas of the generating unit, from decades of real-world experience with numerous changes in coal quality, water quality and electricity demand.

Applicability of any of these upgrades to any of the 1,100 currently existing units is very site-specific. The technical solutions include in general:

- Steam turbine improvements, including computer-designed upgrades of blades and control valves.
- Cooling tower and surface condenser upgrades and programs to reduce cooling water temperature and turbine back pressure, minimizing air leakage into the exhaust steam.
- Variable-speed drive technology for pumps and for motors to reduce power consumption.
- Air heater upgrades to increase heat recovery and reduce leakage.
- Advanced control systems to optimize temperature, pressure and flow rates of coal, air, steam and water.
- Programs to maintain boiler cleanliness when firing coals with low ash fusion temperatures or difficult ash chemistry.
- Coal drying (cleaning, drying, blending, granulation, or chemical treatment).

3.2.1.2 Specific Technologies to Improve Efficiency

For an existing coal-based unit, the potential efficiency improvement attainable varies by unit. The biggest factor is the existing baseline level, e.g., if a plant was previously focused on optimizing efficiency, there will be less room for improvement. Conversely, if attention to efficiency was not as high, substantial gains may be achievable, thereby providing low-cost reductions of CO_2 per unit of electricity generated.

Summarized below are technologies for efficiency improvement, classified in terms of three nominal levels of effort which have been termed “minor”, “average” and “major”.

1. **Minor**. Technologies in this category cost up to $1 million, and typically yield a heat rate improvement of up to 1% on a stand-alone basis. Examples include:

    - Combustion tuning (e.g., low excess air operation, fuel/air balancing, mill performance improvements).
    - Reduction of steam side losses (e.g., turbine steam seals leakage, feedwater flow nozzle calibration, and low-pressure turbine efficiency measurement).

- Installation of efficiency monitoring hardware, along with efficiency awareness courses for plant operators.
- Implementation of on-line performance monitoring system.
- Chemical addition to surface condenser cooling water for cleanliness factor improvement.

2. **Average.** Technologies in this category cost up to $10 million, and may yield a heat rate improvement of 1% to 2%, depending on the application. Examples in this category include:

   - Implementation of commercial software-based optimization systems.
   - "Intelligent" sootblowing systems.
   - Flame diagnostic systems (such as the EPRI Flame Doctor)
   - Utilization of advanced (near-commercial) sensors for mapping of critical gas species (CO_2, O_2)
   - Deployment of targeted chemical injection programs to inhibit slag formation on superheat, reheat and furnace wall sections. An example of this is Fuel Tech's FUEL CHEM® program, incorporating TIFI® Targeted In-Furnace Injection™ technology.

3. **Major**. Technologies in this category can cost well in excess of $10 million, but may yield a heat rate improvement of 2% or greater. Examples of items in this category include:

   - Major modifications or upgrades to condensers (e.g., to improve back pressure).
   - Major modifications or replacement of pulverizers (e.g., to improve particle size distribution).
   - Installation of higher efficiency large motors (e.g., circulation water pump motors) and/or variable speed drives.
   - Cooling tower optimization (e.g., reduced cells in service during winter operation).

3.2.1.3 Combustion Improvements

Combustion improvements burn coal more efficiently. Greater energy is released from the coal, while utilizing less combustion air, thereby producing more electricity per unit of coal.

Means of combustion improvement that are categorized as a minor expense include tuning burners for maintenance of optimal coal/air ratios, thereby minimizing combustion air use (excess combustion air carries heat out of the stack). "Intelligent" control systems are available that analyze completeness of combustion in the boiler, and also adjust firing parameters automatically based on "learning" the optimal operating parameters for changing furnace conditions. The "major" expense category includes coal pulverizer upgrades. The function of pulverizers is to reduce coal size to make the coal easier to burn. Improvements in coal grinding and particle size distribution prevent unburned combustibles, thereby increasing efficiency. The consistency of pulverized coal is similar to that of talcum powder.

After the pulverized coal-air mixture leaves the pulverizer, it enters a classifier, which separates the fine-sized coal from coarser particles by aerodynamic means, and returns the latter for further grinding in the pulverizer. Upgrading the classifier is much less expensive than that of the pulverizer, and can produce the required particle size distribution of the pulverized coal needed for more efficient combustion.

3.2.1.4 Steam Side and Fireside Changes to Improve Efficiency

The basis for efficiency of the steam cycle component of electricity generation is the difference between the temperature of superheated steam entering the steam turbine and the temperature of the exhaust steam leaving the turbine. There are several means of maintaining design superheat steam temperature and optimizing removal of heat/expansion of steam leaving the turbine.

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. This is particularly true with the boilers that frequently cycle to lower loads. Upgrades to the cooling tower heat transfer media may be applicable on certain units, which would yield lower circulating water temperatures. Lowering condenser temperature reduces back pressure, and increases turbine efficiency.

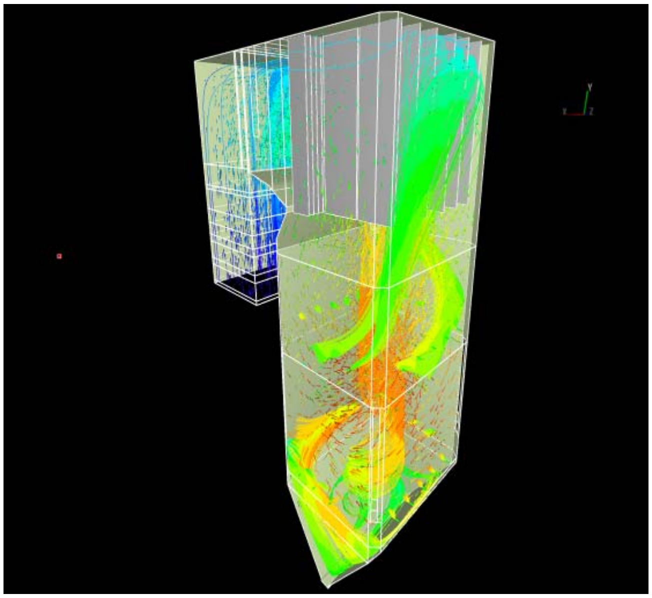
Variable speed drive technology can be applied to pumps and fan motors. By only running large pumps and fans at speeds necessary to support a given load, auxiliary power consumption is reduced. Air preheater upgrades can be applied to many older units. Modern heat transfer media and seal upgrades increase heat recovery and reduce leakage, resulting in better use of heat and energy.

In addition to upgrades in specific steam-side components, heat transfer media in the heat transfer sections, and component motors, programs to maintain cleanliness of heat transfer areas on the fireside also increase cycle efficiency. Mechanical and chemical programs are commercially utilized to maintain greater cleanliness of steam generating tubing and super heater tubes, with respect to the insulating effects of coal ash. This is particularly important as switching away from the coal for which the boiler was initially designed has become more prevalent for SO_2, NOx and cost-related reasons.

This coal switching phenomenon has accelerated in recent years due to the growing use of PRB subbituminous and Illinois Basin bituminous coals. These coals contain high levels of sodium and iron, respectively, which can result in low ash fusion temperatures. In boiler regions where gas temperatures are greater than the initial softening temperature of the ash, tenacious deposits of slag (or fused ash) form on boiler tubes and other heat transfer surfaces.

One approach to inhibiting slag formation is the injection of a chemical reagent directly into the boiler. Utilizing advanced computational modeling (as shown in Figures 3-1 and 3-2) coupled with a proprietary, virtual reality-based, visualization software system, Fuel Tech's TIFI® technology determines an optimal injection strategy whereby magnesium hydroxide is injected in precise dosages at precise locations, thereby ensuring maximum chemical coverage of potential slagging areas in the boiler.

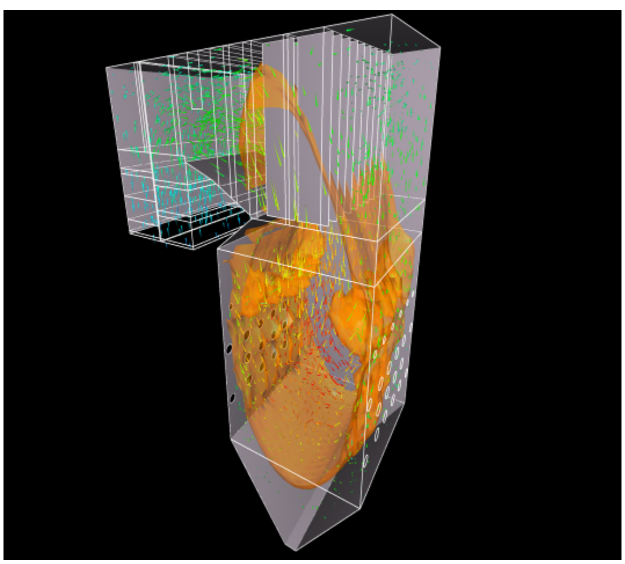
FIGURE 3-1
Computational Models Optimize Droplet Trajectories and Chemical Distribution to Inhibit Slag Formation



Source: Fuel Tech

Upon entering the boiler, the magnesium hydroxide becomes superheated and ultimately forms nanometer size particles of magnesium oxide, which interact with the deposit formation to alter the physical crystal characteristics of the slag as it adheres to tube surfaces. The deposit becomes more friable, enabling the slag deposit to be removed with light sootblowing. Heat transfer surfaces remain cleaner, resulting in improved heat rates.

FIGURE 3-2
Orange Contour Visualizes Likely Slag and Fouling Fronts at Specified Ash Fusion Temperature



Source: Fuel Tech

TIFI® technology has been applied to over 40 coal-based units worldwide, including in the U.S., Europe and China, on units ranging from under 100 MW to well over 500 MW. Many benefits, including greater fuel flexibility, are associated with these chemical injection programs. Application of this technology typically yields returns on investment of 4:1 or higher (i.e., a $1 million annual outlay would yield annual cost savings of at least $4 million). With heat rate improvements being one of the technology's documented benefits, these efficiency enhancing programs also yield reductions in CO_2 emissions – and do so at zero incremental cost.

Opportunities to broaden the application of this technology in the U.S. exist, but are limited in part by regulatory impediments that restrict the ability of power plant operators to pass through the costs of these programs to their customers. For example, a utility wishing to switch to a lower cost fuel, say PRB coal, may determine that a chemical injection program is necessary to avoid expected slagging issues. Because of state regulatory requirements, the utility might be required to pass along the fuel cost savings in the form of a periodic fuel cost adjustment (FCA), but would be unable to recover the cost of the chemical program until such time as it applies for an overall rate adjustment based on all of its costs.

A utility would have a greater incentive to implement this technology, resulting in higher efficiency and reduced CO_2 emissions, if it could include its cost in the FCA. This would reduce the utility's cost structure while reducing CO_2 emissions. One possible remedy would be to expand the definition of "fuel" by the Federal Energy Regulatory Commission (FERC), since most state public utility commissions rely on that definition in calculating their FCAs. This definition is contained in Account 151 of the Uniform System of Accounts prescribed for "Public Utilities and Licensees Subject to the Provisions of the Federal Power Act."

In addition to the foregoing, there are mechanical and chemical programs that exist for maintenance of cleanliness in the surface condenser – the component that converts low pressure steam exiting the steam turbine to water for reuse in the boiler. This is the largest point of heat loss in the steam cycle. Therefore, some level of efficiency improvement can be available on many boilers.

The items listed above are a sampling of options that can offer measurable increases in unit output and/or reductions in CO_2 emissions. In a recent study by American Electric Power, presented to the Asia Pacific Partnership in September 2006, AEP estimated these types of 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 retrofit of emission control systems.

In addition to CO_2 reductions, optimizing efficiency brings significant coal cost savings. In the examples above, and assuming a fuel cost of $2 per million Btus, the plant also would realize $700,000/year in fuel savings for the same 1% heat rate improvement.

3.3 Partial CO_2 Capture: A Near-term CCS Application

3.3.1. Background

RD&D for post-combustion CO_2 capture is oriented toward high levels (approximately 90%). Such technologies presently are not yet commercially available at the sizes needed for large-scale coal-based power plants, and are considered to be too expensive when applied without significant government subsidy. Further, the application of these currently available technologies to existing coal-based power plants would result in significant reductions in plant efficiency and output. It is expected that the technologies to provide 90% CO_2 capture for large-scale coal-based power plants will be commercially available (without government subsidy) in the 2020-2025 period.

Fortunately, the U.S. does not have to wait for commercialization of those technologies at full scale to achieve significant reductions in CO_2 emissions. In the near term, as an important intermediate step, partial CO_2 capture, especially when combined with high generation efficiency, would allow the U.S. to realize the economic benefits of coal-based power generation with CO_2 emissions that are comparable to those of natural gas-fired generation.

Partial CO_2 capture, compared to 90% CO_2 capture, can reduce initial capital cost and the risk of investment, as well as minimize the significant reductions in plant output and efficiency that occur with full CCS application. Also, the experience gained by the operation of such plants would be valuable for future deployments of 90% CCS at full scale. Partial CO_2 capture is a viable means to provide near-term reductions in CO_2 emissions from both new and existing coal-based power plants. This concept can be applied to post-combustion and pre-combustion technologies.

3.3.2 Partial Post-combustion CO_2 Capture

Post-combustion CO_2 capture technologies are described in detail in Section 2. A primary concern for post-combustion retrofit of 90% CO_2 capture technology using today's state of the art technologies is the ability to get the heat needed for the regeneration of the solvent. For currently available technologies, this can amount to about one-half the steam generation being extracted from the existing LP turbine. This imposes serious impacts on the operation and performance of the unit. It is important to maintain sufficient steam flow through the steam turbine to provide proper cooling of the turbine elements. Also, sufficient pressure must be maintained to allow proper operation of the condenser system.

For post-combustion CO_2 capture at PC plants, the most common method considered for applying partial CO_2 capture is to bypass a portion of the unit's flue gas through a CO_2 capture system. The CO_2 absorber equipment could achieve up to 90% capture of CO_2 from the flue gas treated, but only for that portion of the total gas flow. For example, 90% CO_2 capture from 50% of the exhaust gas stream would achieve an immediate 45% overall reduction in the unit's CO_2 emissions, at significantly less capital, operating cost, and performance impact than for treating the unit's full flue gas. This approach is intended to lower the impacts of CCS on the unit efficiency and net output, specifically targeting a reduction in the amount of steam that must be extracted from the steam turbine cycle for solvent regeneration. Total auxiliary power would be less, since the size of the CO_2 compressor would be smaller. However, Sargent & Lundy has conducted a study (2008 Mega Symposium) that showed that implementing CO_2 capture on one-half the flue gas from a large PC unit can still have significant effects on the performance of that plant. It would limit plant turndown to a minimum of 80% in order to provide steam at the desired temperature and pressure for the CO_2 capture process. Operation below that level would require use of high-pressure steam, severely reducing any economic benefits.

An alternative approach to partial CO_2 capture is to use a supplemental steam boiler as an alternative source for steam for the solvent regeneration. This source could also provide electric power using a steam turbine without a condenser, so that the exhaust steam was at the appropriate conditions for the CO_2 capture system. Using natural gas as a fuel, the overall emissions from the treated flue gas and the new gas-fired auxiliary boiler would be less than for a unit with 90% CO_2 capture on 100% of the flue gas. The advantage is the reduction in disruption to the existing steam turbine cycle, and the new source of electricity would support the auxiliary power needs of the CO_2 capture process. Such a system, if applied to the entire PC plant's flue gas, might yield an overall 80% removal, assuming 90% CO_2 capture from the PC unit.

There are other possible scenarios that could be developed which would all be site-specific but could be applied to early adopter units to lower CO_2 emissions with less impact on the existing coal-based fleet in the near term. Compared to "full" capture, partial capture reduces the loss of plant output and drop in plant efficiency, and lowers the overall cost of CCS.

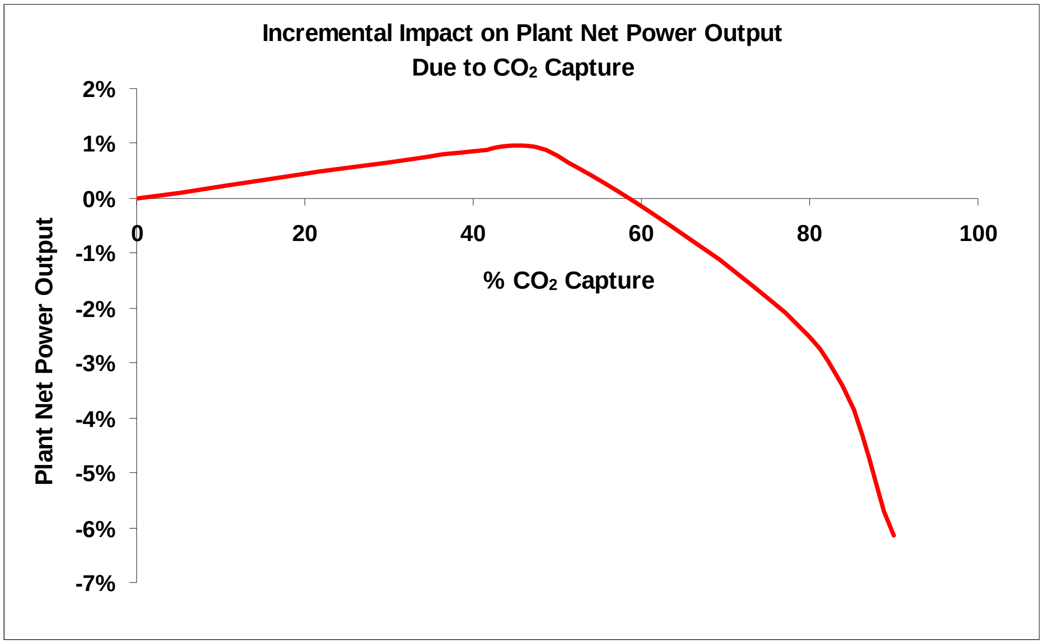
On the existing fleet of PC units, the best candidates for near-term retrofit of partial CO_2 capture would be higher efficiency SCPC units equipped with existing FGD and NOx controls that have sufficient space for addition of CO_2 capture equipment, and are conveniently located near sites where the CO_2 can be stored or used for EOR.

3.3.3 Partial Pre-combustion CO_2 Capture

In IGCC plants**,** there are several options for pre-combustion partial CO_2 capture. For technologies that produce fairly high H_2 content in the gasifier, the CO_2 formed in the gasifier can be removed without the installation of a water-gas shift (WGS) reactor and its associated equipment. For this "limited" CO_2 case, recovery and compression systems can be significantly reduced in size and thus provide partial removal at a lower capital and operating cost for the plant. For these technologies (typically slurry fed gasifiers) it may be possible to achieve up to 40% removal with this concept (Gadde, 2007).

To achieve "high" CO_2 removal rates requires three water gas shift reactors (WGS) in series. This requires a full capital expenditure for equipment and CO_2 compression and a significant amount of steam is required for the WGS reactions. Moderate removal rates could be achieved cost effectively with only a single WGS, which would simplify plant design and reduce capital costs. The impacts of these concepts on the total energy output of an IGCC plant are shown in Figure 3-3. Note that the total plant output increases with CCS up to a point of about 45% removal. This is because the WGS requires significant amounts of water to be present in the syngas. If insufficient levels are present in the syngas exiting the gasifier, water must be added in the form of steam. Injection of steam significantly reduces the overall efficiency of the IGCC facility by reducing the amount of steam available for power generation in the steam turbine. Thus, a more efficient overall plant may remove less than the maximum amount of CO_2, but will have a more reasonable capital and operating cost. Another advantage of partial CO_2 capture is that the derating of the combustion turbine due to the high H_2 content of the syngas can also be reduced or avoided.

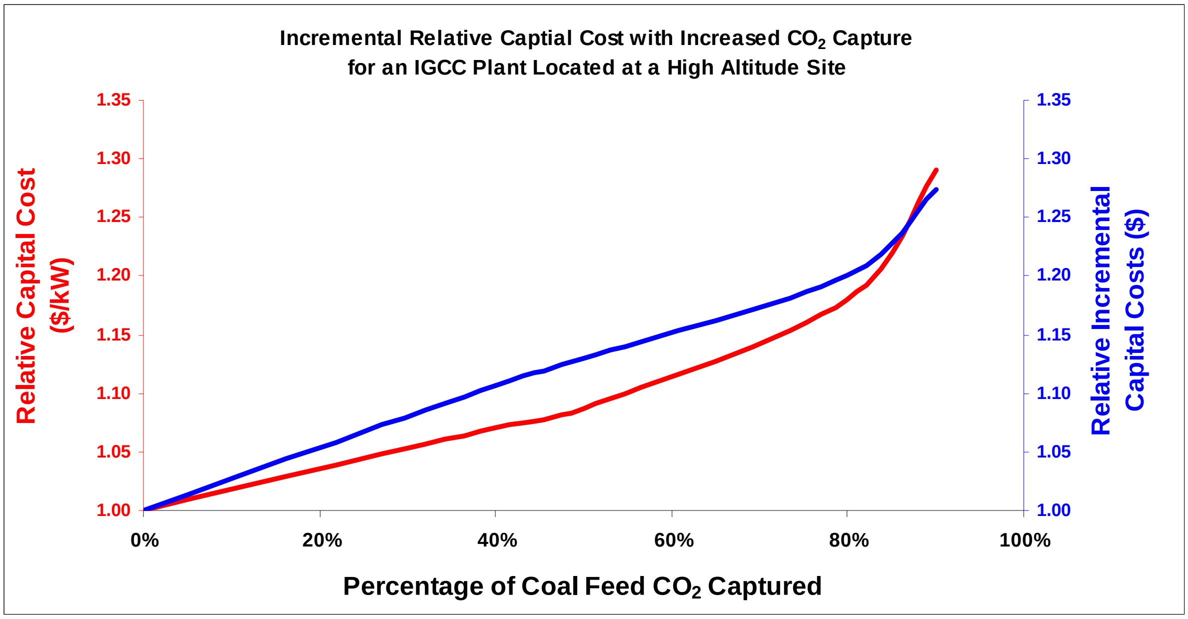
FIGURE 3-3
Incremental Impact on Plant Net Power Output Due to CO_2 Capture



Source: Gadde, 2007

Thus, the overall capital costs are significantly impacted by the degree of CO_2 removal. This is illustrated in Figure 3-4.

FIGURE 3-4
Incremental Relative Cost with Increased CO_2 Capture at High Altitude IGCC



Source: Gadde, 2007

Partial CO_2 capture, combined with high generation efficiency, could reduce CO_2 emissions to those of natural gas-fired generation (1,100 lbs. CO_2/net MWh). This would provide significant, fleet-wide, near-term reductions in CO_2 emissions and accelerate the commercial deployment of CCS at full commercial scale.

Additional analysis of how combining efficiency improvements with partial CO_2 capture (on the existing coal-based generating fleet) can result in immediate and near-term reductions in CO_2 emissions is covered in Section 4 of this report.

3.4 Conclusions

The existing coal-based power generation fleet provides the best opportunity to achieve significant, near-term reductions in CO_2 emissions, in order to help meet the President's goal. By retrofitting commercially available technologies and equipment, improvements to efficiency can be made to existing coal-based generating units. A key result of these efficiency enhancements is a reduction in the amount of coal burned per unit of electricity generated, which results in a direct reduction in emissions. The advantages of these retrofit programs are as follows:

- For the existing coal-based generating fleet, increasing supply (generation) side energy efficiency is a key strategy for low-cost reductions of CO_2.
- Many technologies are commercially available today to provide modest gains in generation efficiency.

The partial capture of CO_2 from the existing coal-based generating fleet also provides for the opportunity to achieve significant, near-term reductions. During the next 5-10 years, a significant number of CCS technologies will be demonstrated, at small and large scales. Until these technologies are commercially available at large scale, there will be good opportunities to retrofit them onto existing units. By implementing partial CO_2 capture on a number of existing generating units, where applicable, additional reductions in the nation's CO_2 emissions can be achieved

The combination of increased efficiency and partial CO_2 capture will provide the means for the nation to reduce its emissions of CO_2 now, without waiting for CCS technologies to be available at large scale for either existing units or new units. Further, some of the losses in efficiency inherent with CO_2 capture can be offset by retrofitting efficiency improving technologies.

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4 Technologies for the Capture of CO_2

Findings

- Due to the growing U.S. and worldwide dependence on coal for the generation of electricity, CCS can and must be an important component of the Administration's effort to reduce overall CO_2 emissions.
- A variety of CO_2 capture technologies are being developed and demonstrated. Many of these technologies hold the promise of providing cost-effective application of CCS for electric power generation.
- For the goal of 90% CO_2 capture and storage from coal-based power plants to be commercially available in the 2020-2025 period, additional government support is necessary for technology demonstration at the commercial scale.
- In the near term, partial CO_2 capture (e.g. 50%), along with efficiency improvements, can serve as an important intermediate step; this will reduce investment risks and lessen the most significant impacts on plant performance and efficiency.
- The 2009 CCPI selections represent the first round of projects that will be necessary to demonstrate integrated CCS technologies. The CO_2 capture technologies demonstrated represent the current state-of-the-art for implementation at commercial scale. These projects will yield valuable information on the operation and integration of these advanced technologies with CO_2 compression and storage operations.

Recommendations

- Due to the complexity and variability of coal-based power plants, it is imperative that a variety of CCS technologies be available to the industry. To support this, the DOE should expand the CCPI and plan for additional rounds of the CCPI to allow for opportunities to demonstrate technologies that have matured through R&D to the commercialization stage. The DOE should also develop more consortia-matching projects (like FutureGen) that will support commercial-scale demonstration of promising CCS technologies.
- To continue progress with development of commercial-scale IGCC with CCS, the Council recommends that the DOE continue to support the FutureGen program, in order to demonstrate high H_2 combustion turbine technology.
- The Council recommends that the DOE increase its financial support for R&D to develop improved high-temperature and pressure materials and validate the use of these advanced materials for boilers, turbines, and other critical components to support the advancement of new higher efficiency power generation equipment.
- The Council recommends that the DOE streamline the application, selection and funding processes associated with the CCPI and demonstration programs.

4.1 State of Knowledge of Existing and Emerging Technologies

To fully understand the challenges, costs, and timeframes for developing CCS technologies, it is first necessary to appreciate how emissions control technology is developed, demonstrated, and commercialized in the power industry. Since the first Clean Air Act of 1970, the power industry has gone through several rounds of implementing emissions control technology for particulate matter (PM), SO_2, and nitrogen oxides (NOx). In each case, there were very similar experiences as the new technologies were applied to this capital intensive and highly-regulated industry, including:

- Unexpected reactions between chemical reagents added to control the pollutants and flue gas constituents;
- Differences in coal characteristics and plant operating conditions, causing wide variations in performance;
- Significant O&M problems that did not show up until after long-term operation; and
- Secondary effects on other components of the power plants were discovered, including higher carbon in the fly ash from low-NOx burners or ammonia in the fly ash from NOx reduction systems (making the ash unusable for construction materials and manufacturing), and changes in concrete characteristics when new chemicals are collected with the fly ash.

In all of these cases, the problems that resulted from the implementation of new technologies had a significant impact on the availability of power generation. The plants were forced to operate at reduced loads and suffered many unplanned shutdowns for maintenance and repair. Over time, solutions to these operating problems were developed and the technologies now operate more reliably. The severity of the impact of the initial problems, both in costs to the consumer and in the reduction of available capacity, depended upon how widespread the technology was applied during the early adopter phase. For example, hot-side electrostatic precipitators were deemed a promising technology for control of PM emissions, and this technology was quickly applied to 150 power plants. Following early successes, longer-term operation resulted in the discovery of a fatal flaw with this technology, costing the industry over a billion dollars. One of the difficulties with implementing new emissions control technology is that the equipment is so massive. For example, emissions control equipment for a 500 MW plant must treat two million cubic feet of flue gas every minute. To minimize the potential detrimental impact of new emissions control technology on the capacity and availability of coal-based power plants, history has shown that the following phases are necessary:

1. Laboratory testing: provides a cost-effective means to determine general feasibility and test a variety of parameters.
2. Bench-scale and pilot-scale: test under actual flue gas conditions but at reduced scale of equipment.
3. Full-scale field tests: scale up the equipment and perform tests under optimum operating conditions to define capabilities and limits of the technology.
4. Full-scale field tests at multiple sites: each new site represents new operating conditions and new challenges, and identifies a range of applicability of the technology.

5. Long-term demonstrations at several sites: Some problems don't show up until after the first year of operation.
6. Commercial implementation: problems will still be found at new sites, but most of the fatal flaws will have already been discovered and resolved.

If an attempt is made to accelerate technology development by skipping one or more these steps, there will be significant potential for operating problems that would lead to untimely shutdowns of the plants using the new technology. Therefore, the process of *implementing new technology in the power industry is a careful, well-planned ten- to fifteen-year process, which still* can provide significant risk to the developers and users (early-adopters) at each stage. Incremental equipment modifications and improvements in operations can be accommodated much more quickly, but it still requires three to five years for implementation at commercial scale.

The development process can be accelerated somewhat by reducing financial risk through federal research, development and deployment (RD&D) support. The process can be further enhanced through the regulatory process by initially establishing lower, more achievable performance goals that gradually increase in stringency over time. This allows for expected improvements in the performance of various technologies as operating experience is gained. This is valuable because most improvements in emission control technologies result after the equipment has been installed and operated for some time. Based on history, there has been a consistent pattern of installing new emission control technology, then the discovery of operating issues and side effects, followed by competition among equipment providers for the development of innovative solutions to the problems that can then be incorporated throughout the industry. Once the regulations drive the installation of new technologies and equipment, improvements do follow. Continued laboratory research to improve a product does not substitute for the problem-solving phase in the field on commercial-scale systems. However, laboratory work may be necessary to help solve specific field problems, once discovered.

Over the past four decades, technologies have been developed that have achieved levels of emissions of the criteria pollutants SO_2, NOx, and PM from the existing fleet of coal-based power plants that are lower today than they were in 1970, even as power produced from coal-based plants has increased by 173%. This has resulted in continuous improvements in emission control technologies. In the early 1970s, flue gas desulfurization (FGD) systems, commonly referred to as "scrubbers", were new and suffered from poor reliability and performance. As operating experience was gained and equipment was modified, SO_2 removal efficiencies rose from about 70% to today's 95-98% levels, with similar improvements in reliability. Reliability improvements have included use of improved materials of construction and hardware components provided by suppliers for pumps, spray nozzles, and filter systems.

Using past technology development as an example provides a pathway to efficiently and cost-effectively address the challenge of meeting the President's CO_2 emission reduction goal. It is noteworthy that there is significant cost and performance loss attached to the capture and compression of CO_2 from both combustion and gasification power plants. Results of studies presented in Table 4-1 provide information on estimates of total plant cost, cost of electricity (COE) and avoided cost of CO_2 for different demonstrated pulverized coal

(PC) plants with post-combustion capture and IGCC technologies, without and with 90% CO_2 capture and compression, respectively. Note that the cost projections provided in the table were determined before the DOE's current study on the costs through FutureGen.

TABLE 4-1
CO_2 Emissions, Efficiency and Costs of Advanced Power Generation Technologies Without and With CCS

CCS	**Supercritical PC (3,530 psi, 1,050ºF)**		**Ultra-supercritical PC (4,640 psi, 1,112ºF)**		**IGCC**	
	Without	**With**	**Without**	**With**	**Without**	**With**
CO_2 Emitted (*lb/MWh*)	*1830*	*258*	*1627*	*223*	*1953*	*239*
Efficiency (% HHV basis)	38.5	29.3	43.4	34.1	38.4	31.2
TCR ($/net kW)	2,800	4,524	2,865	4,408	3,106	3,996
COE (¢/kWh)	6.00	9.64	5.93	9.25	6.44	8.24

Source: CO_2 and efficiency data from MIT 2007. TCR and COE data modified after Booras (2008) to include the effect of the recent increase in construction costs
HHV = Higher Heating Value
psi = pounds per square inch
TCR = total capital requirement

One of the most important challenges with CCS is to reduce the associated costs. Many groups are carrying out in-depth RD&D efforts to reduce these costs and to identify how best to integrate CCS technologies with the existing fleet. The following sections discuss several such options which are in varied states of research, development, and demonstration.

According to the Institute of Clean Air Companies (ICAC), the next ten years are crucial for demonstrating the commercial deployment of CCS with a reasonable increase in COE to consumers. One critical question is how many MW of capacity must be retrofitted with CCS technologies and how many different technologies need to be validated to insure confidence in the full deployment. Present estimates range up to 6,000 MW. ICAC emphasizes the overall concepts of urgency and sufficient subsidization to overcome the near term technological hurdles to full commercial-scale deployment of CCS.

CO_2 capture on coal-based power plants is commonly categorized in three major areas: pre-combustion, post-combustion, and oxy-combustion. Common to all three categories is the process of capturing/concentrating the CO_2 from the other major constituents in the flue gas or syngas, such as nitrogen (N_2). How this process is approached is the fundamental difference in the three areas and each has its own advantages, disadvantages, and trade-offs. Within each category are a broad array of alternative processes, wherein lie the future opportunities to reduce capital costs and parasitic power consumption. It is likely that all three methods will be required for broad-based, commercial-scale deployment of CCS to accommodate a variety of site requirements, financial constraints, and utility needs.

4.1.1 Pre-combustion CO_2 Capture

4.1.1.1 Background

In the gasification process, coal is converted into a synthetic gas, or syngas. This is accomplished by reacting the coal with water (or steam) and oxygen (O_2) or air to convert solid carbon in the coal to a mixture of carbon monoxide (CO) and H_2. The H_2 is produced by the reaction with water (H_2O) in the gasifier. Constituents in the syngas also include CO_2, N_2, hydrogen sulfide (H_2S), ammonia (NH_3), and other trace gases. Ash from the coal is separated from the syngas and discharged as a solid byproduct. The syngas can be used as a building block for production of chemicals, synthetic natural gas (SNG), liquid transportation fuels or fertilizers, or burned as a fuel to generate electricity. Prior to being used for these downstream applications, the syngas is cleaned to remove contaminants that can interfere with those downstream processes or to reduce emissions from syngas combustion.

Coal gasification is a proven technology that has been employed for over 200 years, beginning with the production of town gas by coal gasification, which was used for lighting, heating and cooking prior to the discovery and use of natural gas. The process has been refined and improved over the past several decades. There are numerous suppliers of the technology for large-scale application. These suppliers have developed their own proprietary technologies that are intended to overcome the various challenges of injecting either slurried or dried coal under pressure into a pressurized reaction chamber, achieving a high conversion of the coal to syngas, efficiently removing the ash and other contaminants from the syngas, and improving reliability. Each supplier's technology has its own advantages and disadvantages when compared to others. One technology may work better with some coal types compared to others. The reality is that there is no "best" technology.

When the syngas is used as a fuel for power generation, it can be used in the high-efficiency combined cycle applications that are widely used with natural gas. This combination of coal gasification and combined cycle power generation (IGCC technology) has significant energy and environmental advantages:

- The syngas is cleaned of impurities at high pressure prior to use;
- The syngas is burned in combustion turbines for high energy conversion (first cycle); and
- The waste heat of combustion is used to generate steam for a steam turbine generator (second cycle), increasing overall efficiency of power generation.

The application of combined cycle technology with natural gas yields a very efficient conversion to electricity of 50–55% (HHV basis). Advances in combustion turbine technology, such as improvements in operating at higher temperatures on the first rows of turbine blades, promise even higher electricity conversion rates approaching 55–60%. When syngas is used as the fuel for the combustion turbines, the overall efficiency of the process is typically in the range of 38-42% (HHV basis). As the new combustion turbine technologies become available and are adopted for use with IGCC, they are expected to convert coal to electricity at efficiencies of up to 50%. These efficiency values do not consider the significant energy and efficiency penalties associated with the addition of CCS technology, which are discussed later.

It is necessary to remove impurities from the syngas prior to its use either for power generation or for chemicals production. There are a variety of technologies that have been employed by gasification technology suppliers based on the purity requirements for the syngas application, and the properties of the syngas generated by their gasification technology. These typically employ a variety of filtering, water washing, and chemical absorption to remove impurities. A key focus has been on removal of sulfur-based contaminants from the syngas, primarily H_2S, using acid gas removal technologies common to the petrochemical and chemical industries. Once separated from the syngas, the sulfur is recovered as a byproduct for sale either as elemental sulfur or as sulfuric acid.

The capture of CO_2, which is also an acid gas, can be readily adapted to operation with gasification technologies. This is accomplished by reacting the CO portion of the syngas with H_2O (as steam, in the "water shift reaction") to create a modified syngas composed primarily of H_2 and CO_2. The CO_2 can then be readily separated from the syngas, using the same solvent that absorbs the H_2S, although additional equipment is required in the removal system to selectively regenerate the H_2S and CO_2 from the solvent so that they can be handled separately. This creates a syngas that is primarily H_2, which can then be efficiently combusted in specially designed combustion turbines. N_2 or other diluents may be added to the high H_2 syngas to provide better combustion characteristics, minimize NOx emissions and boost power output.

Specific acid gas removal technologies typically applied for co-removal of H_2S and CO_2 include Selexol™ (UOP) and Rectisol® (Lurgi, Linde). There are four key advantages of CO_2 removal from syngas compared to post-combustion CO_2 capture applications:

1. The technology is applied at the high pressures of the gasification system (typically 450-1,000 psi). Thus the equipment required to treat the syngas is much smaller than for post-combustion CO_2 capture processes which treat much higher volumes of flue gas at near-atmospheric pressures.
2. The relative concentration of the CO_2 is much higher in the syngas compared to that in flue gas. This improves the ability to remove larger quantities of CO_2 from the syngas with less contacting time with the solvent.
3. Many of the solvent technologies require less (or no) heat for regeneration, using pressure differential across the solvent for CO_2 release, which improves efficiency. This is analogous to the "soda pop" effect where CO_2 is released when the can is opened and the pressure is reduced.
4. It is possible to extract the CO_2 at higher pressures from the solvent with syngas, reducing the CO_2 compression requirements for transport of the CO_2 in pipelines and downstream injection for EOR or storage.

The DOE is aggressively supporting research that improves the efficiency and reduces the costs associated with the removal of CO_2 and H_2S from the syngas. These advanced technologies are expected to further improve the overall efficiency of IGCC by two to four percentage points.

One disadvantage of converting CO to H_2 in the syngas is that it reduces the heating value of the syngas. CO has a heating value of about 322 Btus per standard cubic foot (scf), on a lower heating value (LHV) basis. H_2 has a heating value of 273 Btu/scf (LHV). Thus, about 15% of the chemical energy in the syngas is lost in the conversion of CO to H_2. Since the syngas already has some H_2 in it, the actual reduction of syngas heat to the CT is about 10%. Thus, more coal must be gasified to provide the same heat input (in Btus) of fuel to the combustion turbine to achieve its full rated output. In the case of a retrofit application of CCS to an existing IGCC plant, the existing combustion turbine would be derated if the facility is unable to supply the additional syngas.

The water shift reaction is regularly used for the production of fuels and chemicals such as SNG, methanol, NH_3, and with the Fischer-Tropsch process, or direct coal to liquids conversion process, for the production of liquid transportation fuels. For chemical production, typically only a fraction of the CO in the syngas is "shifted" to provide a specific H_2:CO ratio. For IGCC with CO_2 capture, the conversion of CO to CO_2 would be optimized based on level of $CO_2$2 capture desired and the overall economics.

In the future, producing chemicals from coal may prove even more cost effective as the cost for natural gas as a chemical feedstock increases due to high demand. The CO_2 that is naturally separated from the product chemicals is readily available for either EOR applications and/or geological storage.

The applications of these chemical processes that use syngas include CO_2 separation technologies at commercial scale. However, CO_2 capture and separation has not yet been demonstrated in coal-based IGCC applications. It is important that this technology be demonstrated prior to wide-spread deployment. Although problems are not anticipated with the removal of CO_2 from the syngas, there is no commercial-scale experience with the combustion of the nearly pure H_2 fuel in combustion turbines. DOE has supported extensive research to develop combustors for high-H_2 fuels over the past several years. These have not yet been demonstrated at commercial scale. The FutureGen project is anticipated to be the first application for such testing of high-H_2 syngas fuels.

4.1.1.2 Costs and Efficiency Improvements

Presently, there are two coal-based IGCC power plants in the U.S.: Tampa Electric Company's Polk Power Station in Florida, and SG Solutions' Wabash River Generating Station in West Terre Haute, Indiana. Thousands of lessons learned from the operation of these two plants are being incorporated into the designs of the next fleet of IGCC power plants. A major industry source of these lessons learned, as well as advanced concepts for CO_2 capture, is the IGCC User Design Basis Specification, which has been developed by EPRI's CoalFleet for Tomorrow Program. The CoalFleet program includes over 60 industry members, such as electric utilities, technology suppliers, and engineering companies. The specification document, now at over 1,300 pages in length, provides potential IGCC users with process descriptions, system integration concepts, IGCC plant configurations, efficiency improvements, designs for higher reliability, and comprehensive engineering details on the application of CO_2 capture with IGCC technology.

Many of the design enhancements target improved efficiency. There are a number of means by which efficiency of IGCC can be improved. An example is a syngas clean-up process under development at Eastman Chemical's facility in Kingsport, Tennessee. Eastman has been testing a warm syngas clean-up process developed by RTI International. A technical analysis conducted for Eastman by RTI indicated that the warm syngas clean-up process, when applied to IGCC, would improve power output by greater than 9%, and thermal efficiency by 3.6 percentage points, compared to a base case using conventional low-temperature syngas clean-up (typical chemical or physical solvents). The capital cost would be reduced by approximately 14% compared to the base case. Further testing of this promising technology, with DOE co-funding, is planned for Tampa Electric Company's Polk Power Station IGCC plant.

4.1.1.3 Gasification of Biomass

The gasification of biomass has a long history, with numerous applications worldwide, typically for steam and/or power production from direct combustion of the syngas. There are hundreds of suppliers of biomass gasification technologies. Many types of biomass (wood wastes, agricultural wastes, biosolids, municipal solid waste) make excellent feedstocks for gasification because they tend to be very reactive, meaning that it can easily be converted to syngas. However, the physical properties of biomass are very different from coal, so that feedstock handling and preparation equipment needs to be carefully specified based on the type of biomass considered. Processing typically includes shredding and drying to make the biomass easier to feed into the gasifier and to reduce the moisture content and improve overall efficiency. Furthermore, as with coal, a gasifier designed for one type of biomass may not be suitable for other types of biomass.

A limitation to the widespread application of biomass as a feedstock for gasification has been the high cost of transporting it to a central gasification facility. The very large amounts of biomass needed to feed even moderately-sized gasification facilities (due to its low heating value, compared to coal) require extensive acreage. One means of improving transportation related costs associated with biomass is pelletization of the fuel. This process allows for shipping a denser product over greater distances. However, the additional costs of pelletization must be compared to any potential reduction in transportation costs.

The gasification of biomass has been evaluated by many power companies as an effective means of providing a renewable fuel to an existing power plant. Potential applications include:

- Re-fueling an existing coal-based boiler to combust only syngas;
- Co-firing syngas along with coal in the existing boiler; and
- Replacing the coal-based boiler with a new gasification facility that uses biomass (or a blend of biomass and coal) and produces syngas that is combusted to produce steam for the plant's existing steam turbine -generator.

Extensive tests were conducted at Burlington Electric in the 1990s, where syngas from a biomass (wood) gasification system was co-fired in an existing coal-based boiler. Biomass can also be used in blends with coal as the gasifier feedstock. Xcel Energy is planning to install a biomass (wood) gasification system at its Bay Front plant in Wisconsin, replacing all of the coal combusted in an existing boiler with syngas. This will result in a significant reduction in the unit's CO_2 emissions.

4.1.1.4 Fuel Cells and IGCC

Even with the anticipated improvements projected with higher combustion turbine firing temperatures, IGCC power plant efficiency cannot progress beyond the inherent thermodynamic limits of the combustion turbine and steam turbine power cycles, along with lower limits imposed by available materials technology. For this reason, the DOE has been supporting continued development of fuel cell technology that promises even higher efficiencies for conversion of coal to electricity. Several IGCC fuel cell hybrid power plant concepts (IGFC) aim to provide a path to coal-based power generation with efficiency levels of 55-60%.

Along with its high thermal efficiency, the IGFC cycle reduces the energy consumption for CO_2 capture. The anode section of the fuel cell produces a stream that is highly concentrated in CO_2, with some water. After removal of water, this stream can be compressed for EOR or storage. The concentrated CO_2 stream is produced without having to include a water-gas shift reactor in the process. This further improves the thermal efficiency and decreases capital cost and water consumption. IGFC power systems are a long-term solution, however, and are unlikely to see full-scale demonstration until about 2030.

The Solid State Energy Conversion Alliance led by DOE has set up a goal to develop solid oxide fuel cell hybrids in multi-MW sizes by 2015. By 2010, the program will demonstrate a capital cost of $700/kW (in 2007 dollars). The goal is to operate IGFC at a capacity of up to 500 MW by 2020. A pressurized IGFC system with >90% CO_2 capture is expected to achieve an efficiency of >57% (HHV basis), and a COE of 7.3 cents/kWh, compared to a similar size IGCC plant with 90% CO_2 capture and an efficiency of 32.4% (HHV basis), at a COE of 10.6 cents/kWh (Surdoval, 2009).

4.1.2 Post-combustion CO_2 Capture

As noted in Section 1, coal is used to generate over one-half of the electricity consumed in the U.S. and represents approximately 40% of the energy consumed worldwide. It is clear that efforts to reduce global CO_2 emissions must include an element that focuses on CO_2 reductions from existing power plants. The post-combustion CO_2 capture processes being developed for near-term implementation on the existing coal-based fleet draw upon commercial experience with amine-based solvent capture and separation processes used at a much smaller scale in the food, beverage, and chemical industries, including three U.S. applications of CO_2 capture from coal-based boilers. This technology has been shown to be expensive, and much work is required to provide a suite of technologies that can be applied to existing units to accomplish more cost-effective CO_2 capture. Industry and government are conducting extensive research and demonstration projects, as described below. It is imperative that resources be allocated at the national level to ensure that the most promising of these technologies move forward toward commercial-scale application.

The advancement of these technologies will lead to their application both for retrofit to existing power plants and to inclusion in the design of new power plants that are integrated with the application of CCS technologies. There are several attributes that CCS technologies should seek to address to improve the overall economics for both retrofit and greenfield applications. These include:

1. Reduction in heat required for regeneration of solvent solutions
2. Identification of sources of heat that minimize the impacts on an existing power plant
3. Reduction in the amount of water required for the process
4. Reduction in the amount of parasitic power required for the process

5. Minimization of the space requirements for application of CCS technologies
6. Identification of means to reduce the capital and operating costs associated with application of CCS technologies

Industry will be carefully examining technology options as they become commercialized to determine how these attributes are addressed for application at their plants. For new coal-based power generation, the integration of post-combustion technologies will be compared to pre-combustion and oxy-combustion alternatives based on their overall costs and the perceived technical and economic risks of deployment. It is important for the industry to have multiple choices to ensure a competitive basis for selection of the best technologies.

The following subsections provide a summary of existing technology capabilities and the current status for development of new technologies.

4.1.2.1 Liquids

4.1.2.1.1 Commercially Available Amines

Chemical absorption of CO_2 has been used for 70 years to separate CO_2 from natural gas used for high value industrial uses. The post-combustion CO_2 capture processes being considered for power plants in the near-term draw upon commercial experience with amine solvent separation at much smaller scale in the food, beverage and chemical industries, including three U.S. applications of CO_2 capture from coal-based boilers. These applications typically use monoethanolamine (MEA). Only a subset of commercially available amine processes have been operated at coal-based plants, because flue gases contain other pollutants, primarily PM and SO_2. These contaminants degrade the amines and/or cause operations problems such as foaming. In order for these technologies to be applied to existing PC units, additional emission control systems must first be retrofitted; this alone will result in reduced plant efficiency. Then, in order to apply the amine-based technologies at these plants, they will need to be scaled up an order of magnitude.

In amine-based technology, the CO_2 is first captured from the flue gas stream in an absorption tower. The absorbed CO_2 must then be stripped (released) from the amine solution using large amounts of steam to regenerate the solution for recycle to the absorption tower. The recovered CO_2 is cooled, dried, and compressed to a high pressure (>2,000 psi) supercritical fluid. It is then ready to be transported by pipeline for either EOR or long-term storage.

The quantity of steam required for regeneration of a typical amine solution is about one-half of the total steam flow from a typical coal-based power plant. Thus, a plant that generates about 3 million pounds per hour of steam would need about 1.5 million pounds per hour of low-pressure steam at about 60 psi for the CO_2 capture system. The most commonly proposed arrangement for supply of this steam is extraction from the existing steam turbine, usually at the intermediate pressure/low pressure (LP) crossover. This method has operational and efficiency drawbacks, and research is being conducted on other retrofit solutions to reduce the energy demands of post-combustion CO_2 capture.

The resultant energy penalties on a power plant required to recover CO_2 from a typical amine solution include: 1) a reduction of overall plant efficiency by about five percentage points for solvent regeneration, 2) reduction in efficiency by 3.5 percentage points for compression of

CO_2 to a supercritical fluid, and 3) reduction in efficiency of about 1 percentage pint due to other auxiliary power requirements. Overall, this 9.5 percentage point efficiency reduction is a significant impact to a coal-based plant, whether existing or new. To put it in real perspective, a 9.5 percentage point reduction on a PC plant with a "no CO_2 capture" efficiency level of 35% is an actual reduction in overall efficiency of 27%.

High levels of CO_2 capture can also significantly impact a plant's total water demand, primarily due to the need to cool the flue gas before it enters the CO_2 absorber. The following subsections discuss the different liquid-based technologies being considered for post-combustion capture.

4.1.2.1.2 Advanced Amines

Identifying new amine-based solvents for post-combustion CO_2 capture from coal-based power plants is attracting significant interest, because there is a long commercial track record using these solvents in the oil and gas industry. Technology providers are pursuing multiple designs competing to demonstrate efficiency, reliability, and robustness for power industry applications (Klein, 2009). The potential for improving amine-based processes appears significant. Using a mixture of amines, or a different solution, can reduce the energy requirements. A recent study based on an advanced amine suggests that its impact on net power output for a SCPC unit would be only 19% (compared to 30% for MEA). However, the lower energy requirements of these advanced amines have typically resulted in lower CO_2 absorption rates. Research to address this problem has focused on additives such as piperazine (developed by the University of Texas) to increase the absorption rates of those amines that require less energy to capture CO_2. Higher loadings of CO_2 require smaller equipment and lower operating costs, another potential cost savings (Langley, 2009). However, in cases where the amine concentration is being increased, there also may be impacts on the capital costs (due to more expensive construction materials) as well as additional life cycle and O&M costs. There are numerous companies investigating the application of advanced amine formulations for application to post-combustion CO_2 capture.. They include:

- Alstom/Dow
- Cansolv
- HTC Purenergy
- Fluor
- Mitsubishi Heavy Industries (MHI)

Advanced amines are currently being evaluated at the pilot scale. For example, Dow Chemical and Alstom are collaborating on a 2 MW pilot plant to capture CO_2 from a coal-based boiler owned by Dow in South Charleston, West Virginia. The pilot plant will use a proprietary advanced amine technology jointly developed by Alstom and Dow and will capture approximately 2,000 tons of CO_2 per year. The pilot test program began in September 2009 and will run for two years.

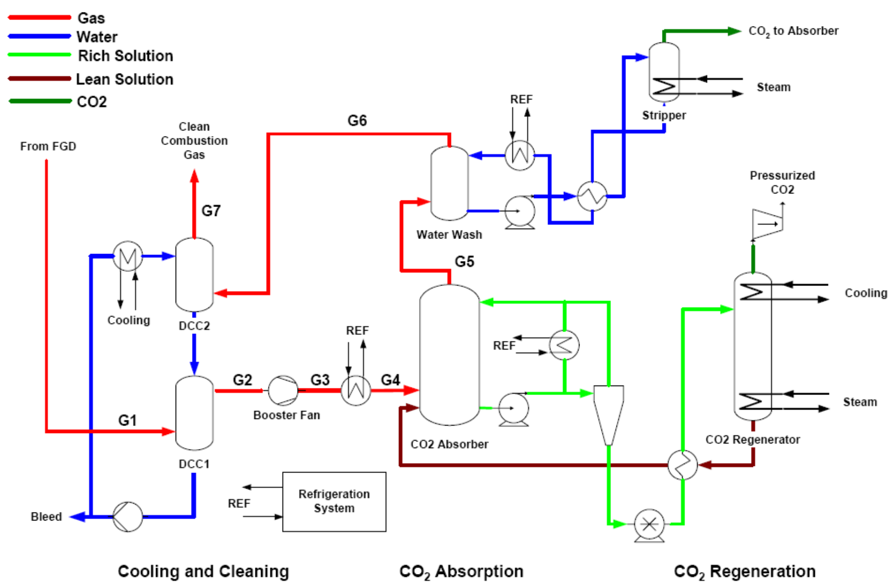
4.1.2.1.3 Chilled Ammonia

Ammonia-based solutions are proposed as an alternative to MEA or advanced amines. A recent study of the economic performance of NH_3-based processes suggests that the amount of steam required to regenerate the NH_3 solvent is about one-third the amount required when using a 30% MEA solution. It also concluded that operating costs could be 15% lower, with 20% lower capital costs. Ammonia, however, has poor mass transfer properties compared to amines, which results in the use of large absorber vessels.

Alstom has developed its proprietary Chilled Ammonia Process, where the volatility of the NH_3 is reduced by cooling the flue gas to the range of 32-68°F. This process is shown in Figure 4-1. The flue gas enters a vessel where it flows counter-currently to an ionic solution consisting of ammonium-based salts to absorb CO_2. The solution is then regenerated by heating under pressure to a temperature of 250°F. A key advantage of this process is the ability to release the CO_2 at high pressure, producing a CO_2 product stream of very high purity and reducing the energy requirements for compression.

Alstom has several pilot and demonstration projects currently operating or in construction, including pilot plants operating at We Energies' Pleasant Prairie Station in the U.S. and E.ON's Karlshamn plant in Sweden, a validation facility currently being commissioned at AEP's Mountaineer Plant in New Haven, West Virginia, and a validation facility being designed for construction at the TCM Mongstad facility in Norway. The validation facility at the Mountaineer Plant will capture up to 100,000 metric tons of CO_2 per year. This site has access to deep saline aquifers that will be used for CO_2 storage. This test started in October 2009 and is projected to continue for a period of 12-18 months. Alstom is currently working with AEP to develop a second phase, commercial-size demonstration that will be designed to capture 1.5 million metric tons per year. These demonstrations will provide information on NH_3 slip.

FIGURE 4-1
Alstom's Chilled Ammonia CO_2 Capture Process



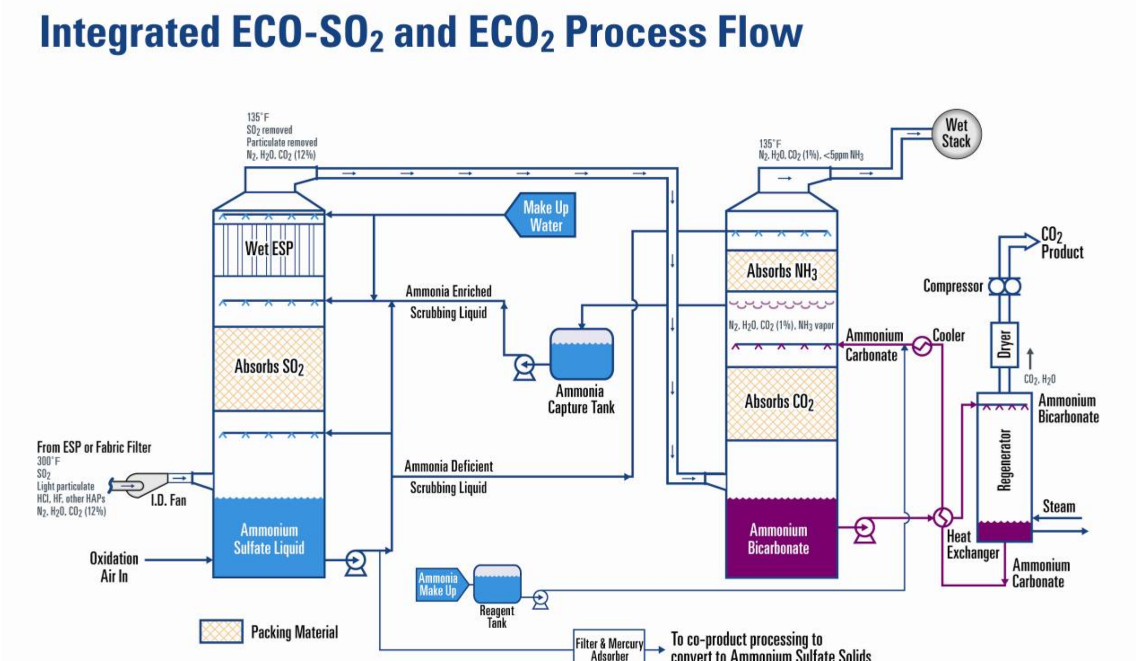
Source: Alstom

4.1.2.1.4 Multipollutant Control with Ammonia

Powerspan's CO_2 capture process, called ECO_2®, is being designed as an add-on system that could be deployed when needed; it is advantageous for sites where NH_3-based scrubbing of SO_2 power plant emissions is already being used.

Similar to the aqueous amines and chilled ammonia, the ECO_2 process is a thermal swing absorption process for CO_2 capture. CO_2 absorption into the NH_3-based solvent takes place at low temperature, similar to temperatures achieved in wet FGD systems. The solvent is then heated to release the CO_2. In the ECO_2 process, CO_2 in the flue gas is scrubbed with an aqueous solution of ammonium carbonate, forming ammonium bicarbonate. CO_2 is released by heating the solution, and it is then compressed for storage while the ammonium carbonate solution is recycled to the absorber for reuse. A general schematic of the ECO_2 process is shown in Figure 4-2.

FIGURE 4-2
Powerspan Corp's ECO_2® CO_2 Capture Process Integrated with the ECO-SO_2 Multi-Pollutant Control Process.



Source: Powerspan

In any NH_3-based CO_2 capture process, NH_3 vapor emissions must be controlled. The ECO_2 process controls the NH_3 release to the flue gas to less than 5 parts per million by volume (ppmv) and recovers NH_3 from the CO_2 product gas for reuse. This is accomplished by using ammonium sulfate from the ECO-SO_2 scrubber as a polishing wash liquid to capture NH_3 vapor.

The ECO_2 technology is currently being pilot tested using a 1 MW slipstream at FirstEnergy's R.E. Burger Plant in southeastern Ohio where a 50 MW application of Powerspan's ECO® multi-pollutant control technology has been operating since early 2004 (see Figure 4-3). The ECO_2 pilot processes a slipstream and is designed for 90% CO_2

capture. The pilot program is expected to run through 2009 and is preparing the technology for commercial-scale CCS demonstration.

FIGURE 4-2
Powerspan's $ECO_2^{®}$ Pilot Test Unit

Source: Powerspan

In March 2008, Basin Electric Power Cooperative announced the selection of the ECO_2 process for a 120 MW commercial-scale demonstration at its Antelope Valley Station located near Beulah, N.D. In July 2009, DOE Secretary Chu announced that the Antelope Valley project was selected to receive $100 million in federal funds under the CCPI, Round 3.

4.1.2.1.5 Ionic Liquids

Ionic liquids, which are molten salts at near ambient temperatures, are a promising option for CO_2 capture, although they are still in the research phase. Ionic liquids have many useful properties with regard to CO_2 capture, including favorable solvation properties, very low volatility, and thermal stability. There is a research project for ionic liquids being supported by the DOE. The goal of this research is to develop new solvents that are cheaper and more energy efficient than competing technologies. The research strategy is an integrated approach involving molecular modeling, experimental property measurement, and process engineering.

Preliminary results for physical-absorbing ionic liquids indicate that their CO_2 capacity is too low for commercial application. Continuing research will focus on increasing the CO_2 capacity while maintaining low regeneration energy. A molecular design strategy is being used to aid research, which includes quantum simulations to target functional groups and mechanisms. Preliminary results show enhanced CO_2 solubility. Issues for thermal stability, viscosity increase, and uptake kinetics still need to be addressed (Maginn, 2008).

4.1.2.2 Solids

Another promising area of research is advanced sorbents, including specialized structured materials and functional adsorbent surfaces, all of which could lead to significant reductions in parasitic energy requirements. The most important potential advantages of solid sorbents are: 1) the heat capacity of the materials is much lower than that of water, and 2) many sorbents can hold more CO_2 per unit mass compared to liquids.

Although CO_2 capture by solid sorbents is in the research phase, and thus has yet to be demonstrated on the scale necessary to reduce CO_2 emissions from power plants, this is not a new technology. For years, solid sorbents designed for CO_2 capture have been used to purify breathing air in confined spaces, such as space shuttles and submarines. There are different classifications of sorbents, such as chemical sorbents that react with the CO_2 and physical sorbents that adsorb the CO_2. Examples of solid sorbents that physisorb (physical adsorption with no chemical reaction) the CO_2 onto the surface include activated carbon, carbon nanotubes and zeolites. These sorbents can be regenerated using a pressure swing or a temperature swing approach.

Chemical sorbents that react with the CO_2 in the flue gas include a support, usually high surface area, with an immobilized amine or other reactant on the surface. The surface area allows for numerous sites for the desired reaction to occur. Examples of commonly used supports are alumina or silica, while common reactants include amines such as polyethyleneimine or sodium carbonate. Chemical sorbents such as calcium carbonate (limestone) can capture both CO_2 and SO_2 at higher temperatures. This option is attractive because it has high CO_2 capture capacity and has been demonstrated over time.

Novel solid adsorbents include metal-organic frameworks, porous crystalline solid materials, such as zeolitic imidazolate frameworks or "ZIFs," which appear to have high CO_2 capacities as well as selectivities and functional fibrous matrices designed to address the capacity and responses in adsorbents. With continued support for R&D, solid sorbents may be able to significantly reduce costs associated with CO_2 capture.

4.1.2.3 Membranes

Membranes offer the promise of a simple separation option with no or few moving parts, but are still in the research phase. They generally consist of thin polymeric films across which some molecules can cross and others cannot. The permeation rates vary inversely with the thickness of the membranes. The current selectivities of polymer membranes fall well below the selectivities of amines. However, combinations of amine/polymeric membrane systems show promise in raising CO_2/NO_x selectivities and are the focus of increased research interest.

Microporous membranes can also serve as platforms for CO_2 absorption and stripping. These membranes serve to separate gases and liquids. CO_2 and NO_x easily transfer through nonselective gas-filled membrane pores with selectivity provided by a liquid, typically an aqueous amine solution (MIT, 2007).

An advantage of membranes is that they require little or no thermal energy for regeneration. However, they do require a pressure gradient across the membrane to function, which represents a different energy penalty that must be evaluated for process application.

4.1.2.4 Carbonic Anhydrase

Absorption of CO_2 into an aqueous fluid is an acid-base reaction and thus, as CO_2 is a mild acid, depends on a strong base to drive the reaction. This can be accomplished by simply by increasing pH (including adding alkali hydroxide, amine, NH_3 or an amino acid, or a carbonate to water), or by addition of carbonic anhydrase (CA). CA provides the fastest reaction with CO_2, even faster than NH_3 or amines. Yet the pH at which this occurs is about 8 vs. 9-10 for amines or carbonates, and about 11 for alkalis. Similarly, CA can catalyze the desorption of bicarbonates to CO_2 with great rapidity and with maximal performance at about pH 5.8 vs. 4 for an alkali.

The SO_2 levels in the flue gas will need to be low for use with CA (<10 ppmv). This is similar to that required by aqueous amines, NH_3, and reaction-based sorbents. Because of the desorption promotion by CA, CO_2 can be desorbed with a modest increase in temperature (to <150°F) versus the substantial increase needed with amines, NH_3, or some carbonates (~250°F). These differences translate to far less energy required for CA-promoted CO_2 absorption or desorption vs. amines, NH_3 or simple carbonates. They also translate into a smaller and more flexible footprint, as the equipment does not need to be in a column configuration. CA for CO_2 capture is currently in the research phase. The CA can be utilized in a liquid, solid, or membrane-based or hybrid CO_2 capture system.

4.1.2.5 Algae for Biofuel

When exposed to sunlight, some strains of algae can use CO_2 to produce high-quality oil during photosynthesis. Technology developers hope to use algae to remove CO_2 from flue gas while producing biofuels. One company estimates that 5,000 to 8,000 gallons per year of oil can be produced from every acre of land devoted to algal growth (Solix, 2009). Therefore, the land requirements per gallon of oil produced are much lower than that of traditional biofuels. This technology is currently being tested on the pilot scale.

4.1.2.6 Catalysis Conversion to Methane or Other Useful Products

When the carbon in fuel is combusted with O_2, CO_2 will inevitably be produced. Some researchers have proposed breaking down the CO_2 and converting it back into a fuel, such as methane. The hydrogen in the methane is often produced via the decomposition of water. However, both CO_2 and water are highly stable, and breaking these compounds into their components requires significant energy input. The energy source that drives the generation of fuel from CO_2 and H_2O must not emit CO_2 itself otherwise overall emissions reductions will not be achieved. Although this research is still in the very early stages of development, the final objective is to reduce the energy required to create a fuel source from CO_2.

Researchers are examining catalysts as well as chemical drivers as potential options to improve process performance.

4.1.2.7 Other Novel Approaches

There are several options that are in the early stages of research, as well as many unlikely to become economically competitive with the alternatives listed previously. For example, cryogenic distillation can readily separate CO_2 and N_2. Unfortunately, this process will not effectively separate the other emissions, such as SO_2 and NOx, so it requires increased implementation of other emission control. In addition, the energy requirements cannot be reduced enough to make cryogenic distillation competitive with other means of separating CO_2.

4.1.3 Oxy-combustion

Combustion of coal in PC boilers uses air as the oxidant. Since air contains approximately 79% N_2, the flue gases from PC boilers contain a weak concentration of CO_2, making it difficult to efficiently capture. Oxy-combustion is the combustion of coal (or fuels produced from coal), as well as other fossil fuels, with relatively pure O_2 instead of air. This avoids dilution of the CO_2 in the flue gas. Stack gas volumes can be decreased to about 24% of air-fired volumes with the elimination of N_2 from the air. Replacing combustion air with a mixture of O_2 and recycled CO_2 mixed at a ratio similar to air, allows for the boiler and environmental equipment to be designed and operated in a fairly conventional manner.

By recirculating cooled combustion products, mainly CO_2, from the boiler exit to the furnace, the combustion products are diluted, and the flame temperature and furnace exit gas temperature can be operated at about the same levels as with air-fired combustion. For similar conditions of heat transfer in the combustion chamber, about 3 pounds of flue gas has to be recirculated for every pound of flue gas produced, resulting in an O_2 volume concentration of about 30%, compared to only 21% for air-fired combustion. This includes about 10% flue gas that is recirculated to transport the coal to the burners. The difference in the O_2 concentrations between air- and oxy-combustion is due to the higher specific heat of CO_2 than that of the replaced N_2, and to CO_2's high radiative emissivity. Flue gas recirculation (FGR) increases the CO_2 concentration in the flue gas to beyond 90% (the balance being mainly N_2 due to air in-leakage and about 3% excess O_2 required for complete combustion of the coal), making the high-CO_2 flue gas ready for compression, transportation and use either for EOR or storage without separation of CO_2 from the flue gas. Presence of O_2 in the gas is not desirable, however, for EOR and other revenue-producing uses of CO_2.

Oxy-combustion does not require heat to regenerate a solvent. Therefore, there is no need to extract significant quantities of steam from the turbine steam cycle. This attribute of the process is particularly of interest as an alternative for retrofitting existing power plants.

Since cryogenic air separation plants are an effective and mature technology, most of the development effort is focused on integrating known, mature and reliable technologies into a new process application that results in the capture of a concentrated stream of CO_2.

Oxy-combustion has matured over two decades from the conceptual stage, with numerous pilot facilities being operated by boiler equipment suppliers. The technology is now ready for demonstration, to validate that it is a viable commercial technology for coal-based power generation with CO_2 capture. There has been a comprehensive effort to assess a variety of design options for integrating heat from the air separation unit (ASU), CO_2 purification unit and process into the steam cycle, and optimizing equipment and process configurations. The objective of these studies has been to: 1) improve oxy-combustion performance and economics, 2) identify the strengths and weaknesses of several equipment and process configuration options, and 3) quantify the performance and economic impact of these variations. A list of operating and planned demonstrations is provided in Table 4-2.

TABLE 4-2
Large-Scale Oxy-combustion Pilot and Demonstration Plants

PROJECT	Location	MWth	Start Up Year	Boiler Type	Main Fuel	CO_2 Train
B & W	US	30	2007	Pilot PC	Bit, Sub B, Lig.	-
Jupiter	US	20	2007	Industr. No FGR	NG, Coal	-
Oxy-coal UK	UK	40	2009	Pilot PC	Bituminous	-
Alstom (Windsor Facility)	US	15	2009	Pilot PC (Tangential)	Bit., Sub B., PRB	-
Vattenfall	Germany	30	2008	Pilot PC	Lignite (Bit.)	**With CCS**
Total, Lacq	France	30	2009	Industrial boiler	NG	**With CCS**
Callide	Australia	90	2010	30 MWe PC	Bituminous	**With CCS**
CIUDEN – PC	Spain	20	2010	Pilot PC	Anth, Bit, Lig, Coke	**With CCS**
CIUDEN – CFB	Spain	30	2010	Pilot CFB	Anth, Bit, Lig, Coke	**With CCS**
ENEL High Pressure Oxy	Italy	48	2012	Pilot Plant	Coal	-
HBPW – Michigan / Praxair	US	225	2014?	~75 MWe CFB	Bit	**With CCS**
Vattenfall (Janschwalde)	Germany	~1,000	2014?	~300 MWe PC	Lignite (Bit)	**With CCS**
Endesa/CIUDEN	Spain	~1,000	2015?	~300 MWe CFB	Anth, Bit, Sub B., coke, biomass	**With CCS**
Black Hills Power/B&W/AL	US	~400	2015?	~100 MWe PC	PRB	**With CCS**
KOSEP/KEPRI Young-dong	Korea	~400	2016	100 MWe PC	Sub B., Bit	-

NG = natural gas
PRB = Powder River Basin
CFB = circulating fluidized bed

Successful completion of these oxy-combustion/CCS demonstration projects is needed to provide the power industry with the confidence necessary to deploy this technology.

Developers of oxy-combustion technology are focusing their process optimization efforts in several areas including:

1. Reducing the energy required for production of O_2
2. Integrating the O_2 production into the overall thermal cycle of the power plant to improve thermal efficiency
3. Redesigning the overall power plant thermal cycle for optimum performance
4. Developing improvements for purification of the product CO_2

There are three types of oxy-combustion: 1) low flame temperature oxy-combustion, 2) high flame temperature oxy-combustion, and 3) high pressure oxy-combustion. All three are applicable to any type of boiler application. The three types of oxy-combustion are discussed in further detail in the following subsections.

4.1.3.1 Low Flame Temperature (Atmospheric Pressure) Oxy-combustion

Low flame temperature oxy-combustion has flame temperatures in the same range as air firing, approximately 3,000ºF. Low flame temperature atmospheric pressure oxy-combustion is currently being tested at a pilot scale. Atmospheric pressure oxy-combustion is quickly moving from the pilot phase of development to the demonstration phase. Demonstration projects include:

- B&W's 30 MW_{th} PC demonstration unit (U.S.)
- Vattenfall's 30 MW_{th} pulverized lignite demonstration plant (Germany)
- CS Energy's 30 MWe Callide demonstration plant (Australia)

4.1.3.2 High Flame Temperature (Atmospheric Pressure) Oxy-combustion

High flame temperature oxy-combustion is in the 5,000ºF range (under a process patented by Jupiter Oxygen). With the high flame temperature, radiant heat transfer from the flame to boiler surfaces is increased due to the T^4 relationship (i.e. a change in temperature has a radiant heat effect of that temperature change to the fourth power). The T^4 higher temperature effect produces more visible and near infrared light which are not strongly absorbed by the flue gas, significantly increasing radiant heat transfer to the steam generating tubes in the boiler, and lowering fuel usage, while maintaining the same tube wall and steam temperatures as air firing. High flame temperature oxy-combustion's tight pressure value O_2 feed controls and lower combustion gas volumes at the burner for near-stoichiometric combustion requires less O_2, lowering O_2 production costs.

DOE has developed an Integrated Pollutant Removal (IPR™) system for CO_2 capture which has been used in pilot plants retrofitted with Jupiter's high flame temperature oxy-combustion technology. High flame temperature oxy-combustion results in low excess O_2 and a lower volume of flue gases with little N_2 and less criteria pollutants (SO_2, NOx, mercury, and PM), simplifying CO_2 capture system requirements. Up to 95% CO_2 capture has been demonstrated, as well as removal of essentially all of the H_2O, PM, low thermal combustion NOx, and SO_2, as well as 90% of mercury (Hg).

The IPR technology is a method of conditioning the non-diluted flue gases into a storage-ready CO_2 stream. IPR integrates PM removal, wet heat exchangers, filtering, flue gas water removal, and compression. IPR water recovery from the flue gas is greater than the boiler feedwater requirements.

4.1.3.3 Pressurized Oxy-combustion

Babcock Power Incorporated and ThermoEnergy Corporation have developed a pressurized oxy-combustion process, the Babcock-Thermo Carbon Capture process (BTCC). The process operates at 1,200 psi and changes the phase equilibria, such that criteria pollutants (SO_2, NOx, hydrochloric acid and Hg) are removed in a condensing heat exchanger, eliminating the need for FGD, selective catalytic reduction, and activated carbon injection (ACI). At the elevated pressure, the condensation temperature is over 500°F, allowing recovery of high-grade heat by the feedwater system. The water vapor content of the flue gas from oxy-combustion of coal can be over 40% by volume, depending on the fuel. The BTCC process also integrates the ASU by pressurizing liquid O_2 and then conducting the combustion at elevated pressure. By using liquefied, pressured O_2, less parasitic power is required compared to compressing it as a gas. Furthermore, condensing CO_2 on the back-end of the combustion process allows liquid CO_2 to be purified by distillation and then pumped to pipeline pressures as a liquid. This requires less energy than compressing CO_2 as a gas and minimizes one of the key parasitic losses associated with CO_2 capture.

The CO_2 capture efficiency of the BTCC process does not change as the flue gas flow rate or system load changes. Accounting for nominal CO_2 leaks during ash removal lockhopper operation, the expected CO_2 capture efficiency of the BTCC process is greater than 95%. Projected power plant efficiencies for the BTCC process are estimated at 35% with existing steam cycles and higher with the ultra-supercritical pulverized coal (USCPC) cycles under development. The BTCC process is currently at the demonstration stage of development. The BTCC process unit operations and basic physics of the unit operations are known or proven in existing industrial applications.

The Canadian Ministry of Natural Resources National Laboratory suggests, as a result of their studies, that high pressure oxy-combustion will improve overall efficiency, reduce equipment size, and separate CO_2 at high pressure. Together, these attributes are expected to provide a competitive option for coal-based power generation with CO_2 capture.

Clean Energy Systems has been developing and testing oxy-combustion systems coupled with a combustion turbine. These systems have been tested up to 200 MWth. The technology being applied is a derivation of the aero-space combustion technology which eliminates oxides and enables CO_2 capture to be relatively economical. In this combustion process, N_2 is extracted from combustion air, so that the flue gas has a high concentration of CO_2. This CO_2 can be readily separated and stored or used for other applications.

In cooperation with Sempra Energy and West Coast Regional CO_2 Capture Partnership, CES plans to demonstrate a 50 MWe system by 2011. The ultimate goal is to demonstrate a 400 MW system using a Siemens advanced combustion turbine and producing approximately 50% thermal efficiency (Bischoff, 2009).

4.1.3.4 Related Oxy-combustion Research

Although many oxy-combustion pilot-scale and demonstration projects are ongoing, research is also being conducted in order to further reduce operating costs. Supporting activities are being carried out at universities and test centers around the world.

4.1.3.5 Alternative Methods for Producing Oxygen

The cryogenic ASU is the standard method of producing O_2. Since this process operates at high pressure and requires significant energy for compression, less energy intensive approaches are being investigated. As current oxy-combustion designs operate at atmospheric pressure, approaches that do not require air compression are expected to be particularly advantageous. A few such approaches are described below:

- Air Products' Ion Transport Membrane (ITM): The ITM process uses non-porous, mixed ceramic membranes that have counter-current ion and electronic conductivity when operated at elevated temperatures, typically in the range of 1,470 to 1,650°F. The ceramics are inorganic mixed-metal oxides (for example perovskites), that are stoichiometrically deficient in O_2, creating O_2 vacancies in the lattice structure. Oxygen molecules from the hot air are absorbed onto the membrane surface where electrons transferred from the membrane cause them to dissociate. An 11-year R&D program started in 1999, and has $148M in funding.
- Praxair's Oxygen Transfer Membrane: Praxair's approach also uses perovskite material. Instead of containing the membranes in an external vessel, they are installed with the furnace. Oxygen passes through the outer wall and hot vitiated air leaves the annulus. The operating temperature range is 1,650 to 2,010°F, which is higher than for the ITM technology, but the governing reactions are the same.
- Linde's Ceramic Autothermal Recovery process: This O_2 production process is being developed by Linde with funding support from the DOE. The process employs the ability of perovskite materials to absorb O_2 in the range of 1,110 to 1,470°F. An O_2-free sweep gas is used to desorb the O_2.

4.1.4 Other enabling technologies.

4.1.4.1 Carbon Offsets from the Use of Coal-combustion Byproducts

Each year, over 125 million tons of coal combustion byproducts (CCBs) are generated by the electric power industry. Fly ash makes up approximately half of the CCBs, while FGD system by-products and boiler ash compose much of the remainder. Today, over 40% of fly ash is re-used by industry; the main use of this fly ash is as a cement replacement for concrete production. About 11% of the fly ash is used in cement blends or as a raw cement clinker feed. Although recycling the fly ash for this purpose clearly reduces the amount of material that must be landfilled, it has the added benefit of reducing GHG emissions related to cement manufacturing. When cement is manufactured, limestone must be calcined, which releases significant amounts of CO_2. For this reason, for every ton of fly ash (which contains varying amounts of calcium oxide) used in cement, approximately 0.8 tons of CO_2 is saved from being released from cement manufacture. This is already a commercial process that can immediately be used to reduce CO_2 emissions.

Another way to measure the environmental benefit of reusing fly ash is by the energy saved. Reusing one ton of fly ash saves the equivalent energy needed to provide electricity to the average home for 24 hours. Even more important to future generations is water savings. Concrete that contains fly ash requires less water than ordinary Portland cement. The U.S. consumes more than 400 million yards of concrete annually. Using fly ash to replace cement in concrete allows for a water reduction of 2 to 10% compared to traditional concrete. Therefore, between 200 million and a trillion gallons of water could be saved annually by including fly ash in concrete mixes. Because fly ash makes concrete more durable, less permeable and more resistant to adverse conditions, structures made with fly ash concrete will not need to be replaced as frequently as other buildings. In life cycle analyses, concrete shows definite advantages over asphalt in roadways and wood in buildings, lowering the overall cost. Using high-volume fly ash mixes would offset the need for additional cement and may actually delay the construction of new cement kilns because some of the demand for cement can be met by fly ash.

Research is still being conducted to encourage expansion of the use of CCBs. One challenge that may become more prevalent in the future is the higher carbon content in fly ash that results from the use of low-NO_x burners or from ACI for Hg removal. More than 5% carbon in the fly ash may render it unusable as cement replacement in concrete production. Research in this area is ongoing and promising (NETL, 2009).

4.1.5 Capture Ready

New coal-based power plants are currently being proposed by power generating companies across the country. It is important that these plants be designed in a way that can allow for the retrofit of CO_2 capture systems in the future. These "CO_2 capture ready" facilities need to consider how to best integrate CCS technology, while not necessarily knowing exactly what technology is likely to be selected. Actual implementation will depend on the timing associated with implementation of CO_2 regulations and the economics associated with the implementation of technology. The following subsections provide guidance for preparing to apply each of the generic technologies at a new installation.

4.1.5.1 Pre-Combustion CO_2 Capture Ready

IGCC technology is still in development, and it is important to prove the technology at large, commercial scale. It is important to first prove the technology at that scale without the additional complexity, performance impacts, and costs of CO_2 capture. However, a new IGCC facility can be designed with CO_2 capture in mind to reduce the impact of its installation after the facility has been commissioned and operated without CO_2 capture. The important considerations include:

- Select an acid gas removal technology that is amenable to both the capture of H_2S and CO_2. Evaluate the design to determine the differences in process layout and leave sufficient space for the additional CO_2 removal equipment required in the future.
- Leave space in the process area for installation of water shift reactors and associated heat exchangers.
- Provide space on the property for the CO_2 drying and compression systems and for the additional electrical transformers and related switch gear needed to provide the electrical feed to the CO_2 compressors.

- Study the plant design to determine the impact of CO_2 capture and H_2 combustion in the combustion turbines to determine the degree of derating that will be incurred. Evaluate the equipment, piping, and control system designs to determine if there is sufficient margin to accommodate the added pressure drop associated with operating at over-design feedstock capacity (typically 5 – 10%). If not, determine if an increase in the design throughput is justified or if the plant economics are acceptable with a derating in plant output.

4.1.5.2 Post-Combustion CO_2 Capture Ready

The power industry expects that there will be legislation and/or regulations that will require CCS. However, as discussed above, technologies for post-combustion CO_2 capture are not yet ready for large, commercial-scale deployment. At the same time, many federal and state permitting authorities are reviewing permit applications with a premise that that any new plant should have the ability to implement CO_2capture.

A new PC power plant can be designed with CCS in mind to reduce the impact of its installation after the power plant has been commissioned and operated without CO_2 capture. The important considerations include:

- Allow adequate space near the plant stack for installation of the CO_2 absorber modules. Consider the ductwork spacing requirements and the need to install additional booster fans.
- Allow adequate space near the turbine-generator building for installation of the CO_2 regeneration systems. This is the preferred location, since large amounts of low-pressure steam are typically required. Also, provide access to cooling water supply and return capability to this area.
- Allow space near the future regeneration area for the CO_2 compression and drying system. Also provide room in the switchyard for the additional auxiliary power transformers and switchgear needed to supply electricity for the CO_2 compressors.
- Evaluate the impact of steam extraction sites for supplying regeneration heat to the CCS process. Consider installation of flanged locations where supply can be extracted from the steam turbine cycle and where condensate can be returned.
- Provide either the maximum level of control of SO_2 and NOx or the upgrading of existing emission control systems to the lowest achievable limits given the fuel and plant configuration.
- Upgrade and optimize the boiler heat transfer surfaces to maximize unit output and reduce parasitic load impact.
- Provide adequate transformer area and switch yard capacity.
- Provide adequate space and arrangements for all necessary interface connections.

4.1.5.3 Oxy-Combustion CO_2 Capture Ready

A new PC power plant can be designed with oxy-combustion in mind to reduce the impact of retrofitting that technology after the power plant has been commissioned and operated without CO_2 capture. The important considerations include:

- Allow adequate space near the plant stack for installation of the booster recirculation fans needed to return flue gases to the boiler.

- Allow adequate space in the area of the burners to allow retrofit of new burners designed for oxy-combustion.
- Provide a site on the property sufficient for installation of the ASU. Ensure that necessary water/steam, etc. can be delivered to this location with minimal disruption to the site.
- Provide adequate space in the electrical switch yard for installation of auxiliary power transformers needed to power the ASU, CO_2 compressors, and booster fans.
- Provide space near the stack for CO_2 cooling and drying. Ensure that a method to transfer cooling water to this location is established in the design and that sufficient cooling water pumping capacity can be added to facilitate the installation.

4.1.6 Partial CO_2 Capture Combined with Higher Efficiency

Partial CO_2 capture is a viable means to provide near-term reductions in CO_2 emissions from both new and existing coal-based power plants. This concept can be applied both to post-combustion and pre-combustion technology. This concept is discussed in detail in Section 4.

The application of technologies that improve the efficiency of existing units can provide immediate benefits by incrementally reducing CO_2 emissions. Technologies that can be employed to existing units for efficiency improvement are described in more detail in Section 3. These technologies can also be applied to units being refitted for partial CO_2 capture to further reduce emissions from these existing plants.

4.1.7 Demonstration and Deployment Strategies

4.1.7.1 Pathways Approach

CCS technology deployment will be necessary to ensure a prominent role for American technology companies, for an improved economy, for an increased technical and scientific expertise base, and for enhanced national prestige. To address the tasks at hand, a scientific approach must be taken to clean coal technology development with the strategic focus of: 1) finding the best CCS pathways in a reasonable period of time so that commercial implementation can commence, and 2) having American companies positioned for domestic and global technology markets in order to strengthen the economy and provide jobs.

Government-funded cooperative agreements (discussed in the following section) are used to try to identify technology "winners" based on grant applications. In some cases, this may not provide a systematic and scientific approach to cover the leading technologies within each pathway. For instance, giving high weights to proposal evaluation criteria such as previous demonstrations or the current state of industrial readiness systematically biases technology selection to well-known approaches. This is not synchronous with the desire for new and different approaches that could represent improvements on what is currently known. If a technology is really new, it may well be too new to be funded by DOE's existing programs. If the national goal for reducing CO_2 emissions is to be equivalent to the Space Race or Manhattan Project, then the funding levels and funding vehicles will need to match those successful government programs as well. With the appropriate funding, these critical new technologies can be quickly demonstrated and brought to commercial scale.

Moreover, each of these pathways needs to be explored and tested in power plants where government vetted performance and economic data could be generated. This data would provide the basis for government regulatory decisions, and as well as for utilities which need to make technology deployment decisions on a free market basis but lack independently reliable information. This is a FutureGen type of approach which is being used for IGCC, and may provide benefit if used for the oxy-combustion and post-combustion pathways as well. Each of the promising technologies within those pathways should be addressed with a decision-tree type of approach.

Furthermore, the scale of projects should be appropriate for reasonably prompt deployment, including advanced pilot demonstration scale, where the next step is commercial application at a new build or retrofit larger scale, which may be at approximately 25 MW or larger depending on the technology. Especially in the current economic situation, the DOE should use smaller as well as larger demonstration projects that would allow more projects and technologies to be tested at an appropriate scale for sound scientific evaluations.

Beyond the technology benefits above, such projects can advance national goals for the enhancing the country's economic recovery effort in the short term, creating permanent jobs in the long run, and raising public awareness of the viability of CO_2 capture for America as a confidence building measure for American citizens as they view our economic future.

4.1.7.2 Grants Approach

The current CCPI program is based on a program that originated in the late 1980s and early 1990s. The focus of this program was collaboration among DOE, state agencies, and industry to help demonstrate new technologies on a scale sufficient to provide information for companies to make commercial decisions. Today, the CCPI is providing government co-funding for new coal-based power generation technologies that can help utilities reduce SO_2, NOx, Hg and CO_2 emissions.

A difficulty with receiving government support for energy projects is the lengthy and complicated process associated with receiving the financial support. The best example is the requirement to conduct a comprehensive NEPA assessment for the projects receiving funds under the CCPI. These activities can add a year or more to project schedules, and result in increased costs just based on the escalation and the need for all of the required associated studies (which rarely, if ever, have any impact on the actual project design). Many of the applications submitted under programs such as the CCPI are for projects which would be located on brown-field sites that would ultimately result in a finding of no impact under NEPA. However, these activities are still required and result in significant expenditure of effort and time that could otherwise accelerate a project to completion and provide earlier CO_2 emission reductions. In this period where action is needed quickly, the associated approval and evaluation processes actually serve to delay these critical projects and the associated CO_2 emission reductions.

4.1.8 Support for Industrial CO_2 Emissions Reductions

This section has focused primarily on capture of CO_2 emissions from the power sector. However, efforts to reduce emissions from other sectors, including those from the industrial sector, are also ongoing. The DOE has a long history of supporting research and demonstrations for clean coal technologies related to the power sector; this knowledge is now being applied similarly for the industrial sector. In June 2009, the DOE/NETL announced a cost-shared collaboration opportunity that was specifically focused on investing in clean industrial technologies and CO_2 storage projects. The funding for this solicitation, which was provided by the American Recovery and Reinvestment Act, was nearly $1.5 billion. The target applications of this solicitation included cement plants, chemical plants, refineries, steel and aluminum plants, manufacturing facilities, and power plants using opportunity fuels (petroleum coke, municipal solid waste, etc.). The cost-shared collaboration is designed for demonstration-scale projects including both the capture and storage of CO_2. The DOE's Industrial CCS target is to support projects that have the potential to capture and store 1 million tons per year of CO_2 by 2015 (DOE/NETL, 2009). The projects that were awarded with funding included everything from coke-to-chemicals plants to cement plants.

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5 Securely Storing CO_2

Findings

- CO_2 has been successfully transported on a commercial basis for over thirty years with the majority of the CO_2 having been used for EOR.
- CO_2 captured from fossil fuel combustion may contain some level of impurities, depending on separation technologies employed, which will need to be considered with respect to transport pipeline materials, compressor design and storage sites.
- Geological CO_2 storage capacity in the U.S. is geographically wide-spread and represents centuries of storage capacity. The DOE's establishment of the seven Regional Carbon Sequestration Partnerships has been very successful in addressing many of the issues surrounding CO_2 storage, but more work is required to qualify tests and develop more and better data from large-scale (>1 million tons/year) demonstrations.
- One of the biggest challenges facing geological storage is the custody and liability issues for the operation and long-term geologic storage of CO_2 at closed-out commercial-scale sites.
- Public outreach and education will be required on a massive scale to reassure the public that CCS can be safely deployed.
- Beneficial use technologies face both technical and economic hurdles to scale-up and to achieve widespread deployment, but they offer a permanent solution to CO_2 emission reductions.

Recommendations

- The Council recommends that the DOE continue its work on commercial-scale CCS demonstrations.
- The Council recommends that the DOE continue its efforts to more fully characterize and document the available geological formations available for CO_2 storage and continue its efforts to better understand the effects of CO_2 storage on geological formations, such as swelling impacts on permeability.
- The Council recommends that the DOE continue to work with other Federal agencies on issues such as long-term liability, and public education and outreach. DOE's CCS expertise can be of enormous assistance to other federal agencies tasked with various CCS-related regulatory requirements.
- The Council recommends that the DOE spearhead the cataloguing of available information to compare and contrast beneficial use technologies and conduct tests to determine which are the most promising. This would expedite the determination of which alternatives are most economically attractive, based on the specific circumstances of a company or plant.

5.1 Pipeline Transportation of Carbon Dioxide

5.1.1 Introduction

Pipelines transporting supercritical CO_2 have successfully been operated since 1972 in the U.S. and Canada. These are mostly large diameter (16 - 30 inch outside diameter), long-distance pipelines for the purpose of supplying CO_2 for EOR. The composition typically being transported in the EOR pipelines consists of 95 to 99.5% pure CO_2 with the remainder being impurities such as N_2, hydrocarbons and other compounds. To efficiently transport the CO_2, the gas is compressed to supercritical state at pressures often exceeding 2,000 psi. In this state, the fluid has density and flow properties more consistent with a liquid than a gas.

CO_2 pipeline designs may include larger quantities of known impurities in addition to some different impurities that may impact pipeline design and operation, depending on separation technologies employed.

5.1.2 Impurities in the CO_2 Stream

Steel remains the most cost effective material for transportation of liquids, fluids and gases in the oil, chemical, and natural gas industries. The product and flow characteristics, discussed below, can damage the steel pipeline by mechanisms such as corrosion and cracking. As noted above, CO_2 has been safely transported in steel pipelines for years but the presence of impurities may be the source of integrity issues. Proper selection of materials and control of the impurities can result in a pipeline that will operate for decades.

The design and location of prime movers (pumps and compressors) may be affected by impurities discussed above. As most impurity levels increase, the prime mover spacing decreases. For example, published calculations show the addition of 10 percent N_2 will double the number of recompression stations needed to keep the pressure at supercritical levels.

1. Water

   Water is the most significant impurity that adversely affects pipeline integrity of a CO_2 pipeline. CO_2 reacts with water to form carbonic acid, which is corrosive. Water in the product stream can be in either a vapor or liquid state. If the water remains in the vapor state, it can be safely transported through the pipe and into injection tube and the geologic formation without corrosion. In the operation of a pipeline, water can condense out of the vapor state into the liquid state at pipeline locations such as valves and bends, so the presence of any water in a CO_2 pipeline can activate the corrosion process. The generally accepted concentration of water is for 650 ppmv in the vapor state for pure CO_2 lines, and lower for pipelines with other reactive impurities. This value is a function of pressure, temperature, and flow conditions and should be considered carefully for each set of conditions. In the design of CO_2 capture system, water should be removed to as low a level as practical.

2. Hydrogen Sulfide and Sulfur Dioxide

   H_2S is likely to be present in a pre-combustion CO_2 capture stream, with SO_2 from a post-combustion CO_2 capture stream. While pipelines that contain CO_2 and H_2S have been safely operated, this impurity must be carefully considered in the design process. While storing this compound along with CO_2 underground would be desirable, the potential release of H_2S is a risk that must be carefully evaluated. The combination of H_2S and water is of greater concern in steel pipelines than the combination of CO_2 and water, since highly corrosive sulfuric acid is more corrosive than carbonic acid. For pipelines that carry both CO_2 and H_2S, the water concentration specification should be lower than for pipelines carrying pure CO_2. SO_2, while not as toxic as H_2S, is a precursor to sulfuric acid when liquid water and O_2 are present. This compound must be considered in a complete corrosion analysis.

3. Oxygen

   The presence of a mixture of CO_2, O_2, and free water can cause corrosion problems in steel pipelines. Internal corrosion in pipelines that contain supercritical CO_2 in solution is influenced by temperature, water chemistry, flow velocity, water wetting and composition, and surface condition of the steel. Oxygen content increases the corrosion process by forming iron oxides rather than protective carbonates. If H_2S is present, reactions with O_2 can form free sulfur. In the worst case, free sulfur deposits on the pipe walls and in valves can clog the pipeline. Low concentrations of O_2 should be maintained to minimize the corrosion rate. Oxygen scavengers can be used to reduce the corrosion rate in the pipeline and well tubing.

4. Nitrogen, Hydrocarbons, Hydrogen, and Argon

   Pipeline capacity and safety can be reduced by seemingly harmless impurities including N_2, hydrocarbons, H_2, and argon in combination with CO_2 as compared to pure CO_2. There is little industry experience in transporting CO_2 with significant amounts of these impurities and most published information only considers binary mixtures of CO_2 and one impurity. It is possible that where multiple impurities are present, interaction between them will also occur, thus resulting in additional modification of the net physical and transport properties that affect pipeline design.

5. CO_2 Capture System Chemicals

   Chemicals used in the CO_2 capture system that could enter the CO_2 stream should be at low levels and can usually be removed before entering the pipeline. Amines have been used for years to remove CO_2 from natural gas prior to transport without significant transportation problems. New CO_2 separation methods should be evaluated to ensure that less benign chemicals are prevented from entering the CO_2 product stream. For example, glycol (used for removing moisture from the CO_2 stream) is an impurity that can contaminate CO_2 pump seals, causing them to fail. Ammonia from the chilled ammonia process is another potential contaminant. Ammonia hydrolyzes water and forms alkaline solutions. It behaves as a solvent and can cause hydrogen embrittlement and promote stress corrosion cracking. Chemicals used in CO_2 capture systems should be carefully evaluated and removed if potentially harmful to pipeline integrity or if they would cause an increased cost by negatively impacting on the cost of the pipeline.

6. Flow Conditions

   Flow conditions have a large influence on the corrosion rate in a CO_2 transport system. Turbulent flow conditions can prevent formation or remove a protective iron carbonate scale exposing more iron to a potentially corrosive product. Conditions favoring the formation of the protective iron carbonate scale are elevated temperature, increased pH (bicarbonate waters), and lack of turbulence. Increasing diameter to reduce flow rate is one method to lower turbulence and reduce corrosion rate, although this increases the pipeline cost.

5.1.3 Industry Practice

There is no industry standard for transporting CO_2, but published practices do exist. A commonly quoted industry practice is the Kinder Morgan specification for EOR. Many other pipelines in the Permian Basin (West Texas and eastern New Mexico) follow the Kinder Morgan specification.

A noted exception is the Canyon Reef Carrier Pipeline owned by Petrosource, with the source of CO_2 being a gas stripping plant and using a 200 ppmv threshold for H_2S. Denbury, which operates a major pipeline system in the Southeastern U.S., also has its own pipeline quality specification.

The Great Plains Synfuels plant in North Dakota produces CO_2 that is captured and transported to the Weyburn Oil Fields in Saskatchewan, Canada for EOR. A cold methanol absorption and regeneration process is used to capture the CO_2; the process also captures sulfur compounds and small amounts of hydrocarbons in the gas form. The composition of the product that enters the pipeline is 96.8% CO_2, 1.1% H_2S, 1.0% ethane, 1.1% other and 0% water “bone-dry”.

5.1.4 Process Specific Comparison

Oil producers have safely transported CO_2 from Colorado and New Mexico for EOR in the Permian Basin for more than 35 years. CO_2-based EOR is currently being practiced in 10 states; associated pipeline networks total about 3,000 miles, with about 400 million tons of CO_2 stored in the Permian Basin. The transported product is at least 95% CO_2, less than 200 ppmv H_2S, and low water content all in the vapor state. There are many similarities for transporting CO_2 for EOR and storage. The differences do not present large technical hurdles and will be able to be addressed during the design of the pipeline.

5.1.5 Regulatory Issues

CO_2 pipelines are currently included in the pipeline regulations under Title 49 CFR Part 195 for interstate Hazardous Liquids Pipelines. These rules pertain to basic aspects of CO_2 pipeline design such as materials compatibility but do not address other issues that can affect significant design aspects and proper operation that are unique to CO_2 transmission by pipeline.

In Europe, it has also been recognized that comprehensive standards addressing the transport of high pressure, supercritical CO_2 by pipeline do not exist. Supported by a group of European and South American partners, Det Norske Veritas (DNV, Norway) is currently leading an international group that is writing a standard for CO_2 transportation by pipeline that is expected to be completed in about 18 months.

5.2 Geologic Storage of Carbon Dioxide

5.2.1 Introduction

CCS consists of the separation and capture of CO_2 from power plant gases or from other stationary CO_2 sources, transport of the CO_2 to a suitable injection site, and injection of pressurized CO_2 into a deep underground geologic formation in such a way that the CO_2 will remain permanently stored. There are essentially five types of underground formations for geologic CO_2 storage, each with its own challenges and opportunities: 1) oil and natural gas reservoirs, 2) deep unmineable coal seams, 3) deep saline formations, 4) basalts, and 5) organic shales.

The CO_2 capacity of formations in North America potentially represents centuries of emissions from large stationary sources (currently about 3.8 Gigatons CO_2/y in the U.S.). Estimates by formation are summarized below in Table 5-1:

TABLE 5-1
Estimates of CO_2 Storage Capacity for Various Geologic Formations

Formation	Billion Tonnes of CO_2	
	Low	**High**
Depleted Oil & Gas Reservoirs	138.2	152.3
Deep Saline Reservoirs	3,297.8	12,618.5
Unmineable coal seams	156.6	177.6
Basalt Formations	TBD	TBD
Shale Formations	TBD	TBD
Other	TBD	TBD

1. Depleted Oil and Reservoirs

   Of the geologic options for CCS, the one with the greatest near-term potential is storage in depleted oil reservoirs. There are several reasons for this. First, oil reservoirs have been extensively evaluated as a result of oil and gas exploration efforts, so a great deal of geologic and other data is already available. Second, injection of CO_2 can lead to EOR, in which the sale of the produced oil can help offset the cost of the CCS project. Finally, it may be possible to use existing wells and other infrastructure in place from the oil and gas industry, thus reducing costs. However, EOR sites are too few and too geographically dispersed to accommodate the quantity of CO_2 that would result from large-scale industrial CO_2 capture operations, should regulations require full-scale CCS.

Because of the economic benefits of increased oil production, EOR projects are likely to provide some of the earliest opportunities for CO_2 storage. As a value-added benefit, CO_2 injected into a mature oil reservoir can result in the production of additional oil. When CO_2 is injected into an oil reservoir, a small amount of the injected CO_2 dissolves in the oil, increasing the bulk volume and decreasing its viscosity, thereby facilitating flow to the wellbore. CO_2 injection typically allows recovery of an additional 10–15 % of the oil.

2. Deep Saline Reservoirs

   A second CO_2 storage option is in deep saline formations. Saline formations are widely distributed globally and can potentially hold hundreds of years of CO_2 emissions from large point sources at current rates. CO_2 can be more efficiently stored as a supercritical fluid in a saline formation rather than a gas, but this requires the formation to be at a minimum depth of about 2,500 feet to achieve favorable geologic storage conditions. Minimizing drilling costs will require a formation close to the 2,500 foot limit. Because supercritical CO_2 is less dense than saline water, the injected CO_2 tends to rise due to buoyancy effects. A suitable caprock formation above the targeted saline formation must be verified in order to contain the CO_2, as fractures and faults would allow CO_2 to migrate upward to the surface.

   Several mechanisms for trapping CO_2 are concurrently active in a typical saline storage formation. First, structural trapping is the simple displacement of formation fluids, and stratigraphic trapping is the retention of CO_2 by the caprock. Second, there is solution trapping, resulting from the dissolution of CO_2 in the saline water. Once dissolved in water, CO_2 is no longer buoyant, although a partial pressure of CO_2 is necessary to keep the CO_2 in solution. The final trapping mechanism is mineralization, in which dissolved CO_2 reacts with formation rocks to form stable carbonates.

3. Unmineable Coal Seams

   Unmineable coal seams are particularly attractive CO_2 storage reservoirs. Unmineable coal seams are seams that are too deep or too thin to be economically mined. Injection of CO_2 into these coal seams could be beneficial due to a relatively large storage potential (both domestically and globally), with the added benefit at some sites of enhanced production of methane from the coal. Laboratory investigations, small scale field tests, and numerical modeling results are encouraging but highlight the need for detailed understanding of both CO_2 sorption under formation conditions (to improve estimates of capacity) and the dynamic response of coal to CO_2 sorption (which may either enhance or degrade injectivity). If these issues can be successfully addressed, the potential benefit derived from methane production could provide a strong incentive for the rapid commercial deployment of CO_2 storage in unmineable coal seams.

4. Basalt Formations

   Basalt formations are geologic formations of solidified lava and possess a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus isolating it from the atmosphere permanently. Basalt is a dark-colored, silica-rich, volcanic rock that contains cations—such as calcium, magnesium, and iron—that can combine with CO_2 to form carbonate minerals. Any lava with less than 53% silicon is known as basalt. Major basalt formations that may be attractive for CO_2 storage occur primarily in the Pacific Northwest, the southeastern and northeastern U.S., and at several other locations around the world. Unlike sedimentary rock formations, basalt formations have unique properties that can result in chemically trapping injected CO_2. Issues exist with permeability and porosity that must be explored on a site-specific basis.

5. Shale Formations.

   Shale formations, the most common type of sedimentary rock, are characterized by thin horizontal layers of rock with very low permeability in the vertical direction. Many shales contain 1–2% organic material in the form of hydrocarbons that provide an adsorption substrate for CO_2 storage similar to CO_2 storage in coal seams. Organic rich shale reservoirs may behave similarly to unmineable coal beds and desorb methane in the presence of adsorbed CO_2. Research is focused on achieving economically viable CO_2 injection rates, given shale's low permeability and low porosity and the need to drill the formation extensively to disperse the CO_2.

The following conclusions can be drawn concerning geologic storage of CO_2.

- Geologic storage offers great potential for meeting the President's goal of reduced CO_2 emissions. Of the geologic storage options, storage in depleted oil fields offers the greatest near-term potential. Reasons for this include: a stratigraphic trap is assured; a great deal of information is already available because of extensive exploitation; enhanced oil production can help offset costs; existing infrastructure may be useable, further reducing costs; and regulatory issues should present fewer problems because CO_2 has been used extensively for EOR.
- A variety of EOR related tests are underway that will improve monitoring, verification and accounting (MVA) tools, including mathematical models, improved capacity estimates, and a framework to assist in developing regulatory protocols, risk assessments, and mitigating actions, should a problem arise.
- The technical feasibility of injecting CO_2 into saline formations has been demonstrated by the Regional Carbon Sequestration Partnerships (RCSP) and is discussed below. However, much work is still needed to reach full commercial scale in a variety of formations.
- Coalbed methane production (which currently represents about 10% of domestic gas production) can be significantly enhanced in conjunction with CO_2 storage.
- Understanding the dynamic response of coal to CO_2 flow, such as swelling that impacts permeability, remains a key scientific challenge and is the focus of several RCSP field tests and ongoing laboratory/theoretical efforts within DOE's CO_2 storage program.
- Basalt formations have unique properties that can result in chemically trapping injected CO_2, thus effectively and permanently isolating the CO_2 from the atmosphere.
- Organic-rich shale formations may behave similarly to unmineable coal beds and desorb methane as CO_2 is adsorbed. Research is focused on achieving economically viable CO_2 injection rates, given shale's low permeability.

5.3 Success of the Regional Carbon Sequestration Partnership Program

5.3.1 Introduction

The DOE established the seven RCSPs (made up of state agencies, universities, private companies, national laboratories, environmental groups, and nonprofit organizations) to address the challenges arising from the varied geology, climate, economic activity, and public attitudes across the U.S. Collectively, the RCSPs include more than 350 entities and span 43 states and four Canadian provinces. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-based CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all of the potential geologic storage sites in the U.S.

The RCSPs are tasked with determining the technology, infrastructure, and regulations most appropriate to promote CO_2 storage in their regions of the country. This public/private partnership is extremely important to the successful deployment of CCS. Industry involvement is key, since technology transfer will be occurring at the same time that CCS is being implemented.

Implementation of the RCSP Program involves three phases:

- Phase I began with the characterization of CO_2 storage opportunities for each of the seven regions (2003-2005),
- Phase II followed with field tests to confirm and validate regional CO_2 storage opportunities (2005-2009).
- Phase III consists of large-scale field CO_2 storage tests (2008-2017).

The three phases are interrelated, with each subsequent phase augmenting and building upon the previous phase. The highly successful first phase identified all of the significant point sources in each region, broadly identified potential geologic storage sites, and estimated the potential storage capacity of depleted oil fields, unmineable coal seams, and deep saline formations. Phase II consists of small-scale tests at the most promising sites identified in Phase I. Building on lessons learned from Phase II, Phase III involves large-scale tests (up to 1 million tons of CO_2 per year per test). This information is summarized in the "Carbon Sequestration Atlas of the United States and Canada (Second Edition)" which can be accessed at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII

The IEA has validated that the RCSPs and their large-scale CO_2 tests are the world's most ambitious and will significantly advance CCS in the U.S., Canada, and internationally. The IEA found that the seven RCSPs are unique in that no other country or region has initiated such an ambitious CO_2 storage effort. The IEA's findings indicate that:

- The projects are realistic, achievable, and should be implemented immediately to benefit national and international governmental organizations that will be responsible for establishing CO_2 storage projects.
- The projects are comprehensive and together comprise a major research initiative.
- No other country or region is undertaking such an ambitious program.

- Phase III is an excellent program that will achieve major results for the U.S., Canada, and the world.

5.3.2 Key CCS Issues are Being Addressed by the RCSPs

There are a number of key issues that must be addressed before CCS can be deployed on a large scale as a GHG mitigation strategy. These issues include:

- Site characterization
- Validating capacity and long-term storage
- Permitting
- Site development
- Site operations
- Site closure
- Liability
- Public outreach and education

5.3.2.1 Site Selection and Characterization

Site selection and characterization is the first step. Each RCSP broadly characterized promising geologic formations in their respective regions using mathematical models to estimate the storage capacities of saline aquifers, unmineable coal seams, and depleted oil reservoirs. This information is summarized in the DOE's "Carbon Sequestration Atlas of the United States and Canada (Second Edition)"

The results of the characterization activities showed that there are hundreds of years of capacity available to store CO_2 from large CO_2 point sources in the U. S. and Canada. A decision support resource for each region was developed to evaluate the suitability of the CO_2 sinks.

Many factors will affect this evaluation, including geologic characteristics of the target formation, characteristics of the cap rock, potential storage capacity, distance from the CO_2 source, availability of leases and rights-of-way, and existing infrastructure. Once a search has been narrowed to a few potential sites, a detailed site characterization is undertaken to ensure that the site is suitable. Primary tests for the initial identification of a qualified storage site include 2-D or 3-D geophysical surveys. If a well is drilled, a number of other tests will be applied to confirm the site characterization. In addition, site modeling and the simulation of reservoir performance will be carried out. A continuing effort is needed to identify and fully characterize potential geologic storage sites. Site characterization is the most time-consuming and costly part of the CO_2 storage site selection process.

5.3.2.2 Validating Capacity and Long-Term Storage

The most critical site selection issues include target formation capacity and cap rock integrity to prevent CO_2 leakage into underground drinking water sources or the atmosphere.

The Validation Phase (Phase II) requires pilot-scale field demonstrations to have a site-specific focus and verify estimates of site capacity and cap-rock integrity. Additional outcomes are the validation and refinement of existing CO_2 reservoir models; the development of coupled models, demonstration of geologic seal integrity; validation of MVA technologies; definition of project costs; risk assessment of operational and long-term storage of CO_2; addressing regulatory requirements; and education and outreach efforts for the public and stakeholders. The RCSPs have conducted 22 geologic storage injection tests during Phase II.

5.3.2.3 Permitting

Geologic CO_2 storage projects are covered under the Safe Drinking Water Act (SDWA). In its March 2007 guidance, the EPA clarified the permitting process by indicating that CO_2 storage met the definition of "underground injection control (UIC)" under the SDWA.

One of RCSP's stated goals for the Validation Phase (Phase II) is to develop regulatory compliance plans for geologic CO_2 storage. As Phase II progressed, the RCSPs worked with a variety of federal and state agencies to get projects permitted. As a result of the RCSPs' pioneering efforts, the EPA is now actively collaborating with DOE (and the RCSPs) to establish an effective regulatory framework for geologic storage of CO_2.

The RCSPs' Phase II demonstration wells were permitted under a variety of UIC well classes, due in part to the diversity of the projects and in part to differences in the permitting institutional structure; 80 percent of the Phase II projects were permitted by state agencies under UIC with 60 percent permitted under Class II and 28 percent permitted under Class V (experimental).

Phase III wells are anticipated to be permitted under the existing UIC classes of injection wells. In the event that EPA issues new regulations for the new classification of "Class VI" wells before projects apply for injection permits, these projects will likely be permitted as Class VI injection wells. The RCSP initiative has contributed to the positive development of a UIC well class specifically for geologic CO_2 storage by helping EPA make informed decision about the requirements for compliance with the new well class.

5.3.2.4 Site Development

Following site characterization and permitting, the next major activity for geologic storage projects is site development. It is anticipated that for the RCSPs' large-scale tests, CO_2 will arrive at the site by pipeline at a high enough pressure so that additional compression is not required. Therefore, site development will consist mainly of well drilling and construction of surface facilities, such as access roads, distribution lines, and control buildings. As additional geologic information is generated from well drilling, computer models of the site will be updated.

Depending on the location of the CO_2 source and the location of the storage site, site preparation may include pipeline construction. Typically, compression and dehydration to avoid pipeline corrosion will occur at the CO_2 source and will not be part of site development; however, if the pipeline is long, booster pumps may be required.

5.3.2.5 Site Operations

Site operations consist of injection, monitoring and performing required maintenance. Operations monitoring and reporting will be driven by the requirements of the operating permit and by the documentation required for verification of injected volumes. Operations and monitoring staff will be needed at stand-alone sites, but if the injection site is located at an industrial site, it may be possible to integrate operations and staff into the existing facility.

Procedures will be developed to understand wellbore storage or pipeline storage volumes should repairs, planned maintenance, or out-of-bounds conditions leading to atmospheric venting of CO_2. Accurately estimating these volumes may become important to third-party verification or to local regulators. Data from the RCSPs' field tests will help develop the most effective and efficient operating procedures and form the basis for operating standards for commercial-scale projects.

5.3.2.6 Site Closure

When a site has reached its full capacity, it will have to be closed and monitored, but regulatory requirements for closing a previously active CO_2 injection site have not yet been established. The focus of geologic storage well abandonment procedures will be to ensure site integrity for as long as current technology permits.

Preparation for well abandonment starts with initial well installation, including the use of corrosion resistant materials, the proper installation of well components, and the selection of well casing materials and cement that offer sufficient resistance to CO_2 attack. A condition assessment program will be required to verify each well's leak resistance. Existing remediation techniques will be used to address problems. Typical post-injection well abandonment will include a comprehensive below-ground cement sealing procedure. Documentation will capture all required details before being submitted to the appropriate regulatory authority. When sealing activity is complete, the closed injection site area will be restored for other acceptable uses. Results from the RCSPs' Validation and Deployment Phase tests are providing information that will be invaluable in establishing site closure protocols.

5.3.2.7 Liability

The RCSPs have addressed operational custody and liability concerns for CO_2 injection during the Validation and Deployment Phases through compliance with federal and state requirements for the UIC Program. Lessons learned from these forerunner projects will contribute significantly to development of risk management approaches for commercial-scale, long-term geologic storage projects.

The custody and liability issues for the operation and long-term geologic storage of CO_2 at abandoned commercial-scale sites have not been resolved. This is one of the biggest challenges facing geologic storage. Injected material will require management for hundreds of years, which is beyond the capability or existence of any private sector organization. Therefore, responsibility will have to reside with a governmental authority. The RCSP program has led efforts by governmental organizations and other stakeholders to begin addressing this issue.

5.3.2.8 Public Outreach and Education

Public outreach and education is a priority for the RCSPs. Each RCSP has a Lead Outreach Coordinator who has assembled a team of technical experts and communications professionals tasked with information dissemination and interactive communication with both stakeholders and the public. Public outreach is being tailored to the specifics of each project because public perceptions and concerns related to CO_2 storage projects will vary depending on project details and location.

Typically, a multi-level approach is used that focuses on the communication needs of the general public and local stakeholders. This approach provides awareness and understanding for the general public and detailed information and feedback opportunities for stakeholders. Proactively providing high-value information to each group assures that understanding is achieved and that feedback can be incorporated at an early stage of the specific project to support its success.

Education is also important for developing CO_2 storage capabilities. CO_2 storage will require many people with specialized education, knowledge, and experience. The requirement for human capital will be as great as that of the oil and gas industry; and, thus, shortfalls could occur for this valuable human resource. The RCSPs are a proven building block in this educational process. However, further educational efforts are needed to ensure a sufficient future supply of geologists, engineers, and scientists to build and operate a CCS industry.

5.3.3 Validation Phase (Phase II) Field Projects

The RCSP Validation Phase, initiated in 2005, is focusing on the implementation of field tests to validate the efficacy of CO_2 storage technologies in a variety of geologic sinks throughout the U.S. The seven partnerships are conducting a series of geologic field tests across a variety of resources and techniques. The small-scale field tests in the Validation Phase focus on testing CO_2 storage in depleted oil and natural gas fields, saline formations, unmineable coal seams and basalt formations. Appropriate measurement and monitoring technologies are being employed to track the movement of stored CO_2 and to satisfy compliance requirements associated with injection well monitoring requirements. Under the Validation Phase, the partnerships continue to characterize regional storage opportunities; maintain regional geographic information systems and decision support systems; permit field projects through the appropriate regulatory agencies; and implement public outreach and education activities in the communities where the field projects are located.

5.3.3.1 Validation Phase Accomplishments to Date

The Validation Phase is conducting small-scale field demonstration projects across diverse regional and geologic settings to confirm the capacity values determine during the characterization phase and perform the activities required to support these tests. Projects were selected based on regional geologic information gathered during the Characterization Phase and are being used to further develop instruments and numeric models used for CCS applications.

Each RCSP pilot project is working to develop innovative MVA techniques from nano-degree tiltmeters and satellite detection that can map millimeter changes in the earth's surface to high resolution geophysical imaging to detect CO_2 movement through the geologic storage site and to evaluate potential leakage pathways. The following subsections describe some of the accomplishments of the Validation Phase.

5.3.3.1.1 RCSP Validation Field Tests in Depleted Oil and Gas Fields

Nine CO_2 storage pilot field tests are being conducted in oil fields to promote EOR while simultaneously storing CO_2. Depleted oil and natural gas reservoirs provide ideal sites for CO_2 storage field tests for several reasons: 1) the fact that these reservoirs have retained hydrocarbon deposits for millions of years demonstrates that they are tight and will likely retain injected CO_2; 2) there is typically a large amount of site geologic data from the oil and gas industry, and 3) there is the potential for increased hydrocarbon production, through the displacement of oil and natural gas, that can help offset CO_2 storage. The RCSPs have identified a CO_2 storage potential in depleted oil and natural gas reservoirs of 138 billion metric tons of CO_2 across the U.S. and Canada.

5.3.3.1.2 RCSP Validation Field Tests in Saline Formations

Six CO_2 storage pilot field tests are being conducted in deep saline formations. The areal extent of saline formations vastly exceeds that of oil and natural gas fields so the potential for storing CO_2 in these formations is very large. However, the chemistry involved is much more complex, and there is less assurance of containment, since a saline formation can exist without an impermeable cap rock. The RCSPs have estimated that saline formations have the potential to store between 3,297 and 12,618 billion metric tons of CO_2.

5.3.3.1.3 RCSP Validation Field Tests in Unmineable Coal Seams

Five CO_2 storage pilot field tests involving injection into unmineable coal seams accompanied by enhanced coalbed methane (ECBM) production are being conducted. Methane strongly adheres to coal surfaces, but when CO_2 is injected into a coal seam, it displaces the methane. Sale of the coalbed methane produced can help offset the cost of CO_2 storage.

5.3.3.1.4 RCSP Validation Field Test in Basalt/Mafic Rock

One CO_2 storage test in basalt/mafic rock with permanent CO_2 storage through mineralization is being conducted. Flows and layered intrusions of basalt occur globally, with large volumes being present in the U.S., especially in the Northwest.

5.3.4 Regional Carbon Sequestration Partnership Large-Scale Phase III Development Testing

The RCSP Phase III Development activities, proceeding as an extension of the work completed in the Characterization and Validation Phases, will demonstrate that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically at a large scale for hundreds of years. Phase III testing involves the injection of 1 million tons or more of CO_2 into a regionally significant geologic formation. These tests will promote understanding of injectivity, capacity, and storability in various geologic formations across a variety of regional settings. Results and assessments from these efforts will help in the commercialization efforts for future CO_2 storage.

5.3.4.1 Specific Objectives of Development Phase

The geologic structures to be tested may become candidate sites for future near-zero emissions power plants. The primary goal of the Development Phase is to establish large-scale CO_2 storage projects across North America, where large volumes of CO_2 will be injected into a geologic storage formation containing significant CO_2 storage potential in each region. Each project will inject CO_2 over several years. While injection volumes will vary, each project will maximize CO_2 injection volumes and fully utilize the infrastructure of its region. Projects that procure CO_2 from post-combustion CO_2 capture facilities and industrial vents will inject at least 1 million tons, while projects receiving CO_2 from natural gas processing plants or natural vents will inject over 1 million tons, depending upon cost and availability. The Development Phase tests will be implemented in three stages, to test key technologies during the project's life-cycle.

5.3.4.2 Development Phase Timeline

Years 1-3:

- Detailed site selection and characterization;
- Permitting and NEPA compliance
- Well completion and testing;
- Infrastructure development

Years 4-7:

- CO_2 procurement and transportation;
- Injection operations;
- Monitoring activities

Years 8-10+:

- Site closure;
- Post injection monitoring;
- Project assessment

While projects in the Validation Phase were designed to demonstrate that regional CO_2 storage sites have the potential to store thousands of years' worth of CO_2 emissions, the tests in the Development Phase will address practical issues such as sustainable injectivity, well design for both integrity and increased capacity, and reservoir behavior with respect to prolonged CO_2 injection. Development Phase goals include: 1) collecting physical data to confirm capacity and injectivity estimates made during the Characterization Phase; 2) validating the effectiveness of simulation models to predict and MVA technologies to measure CO_2 movement in the geologic formations, confirming the integrity of the seals, and confirming indirect storage in terrestrial ecosystems; 3) developing guidelines for well completion, operations, and closure in order to maximize storage potential and mitigate leakage; 4) developing strategies for optimizing storage capacity for various reservoir types; 5) developing public outreach strategies and communicating the benefits of CO_2 storage to various stakeholders; and 6) satisfying the regulatory and permitting requirements for CO_2 storage projects.

5.3.4.3 Development Test Highlights

Table 5-2 lists the site location, site geology, injection schedule, and accomplishments of the nine RCSP Phase III tests. Since the Development Phase is at a very early stage (initiated in 2008), the majority of the Phase III tests have either just begun site characterization or are still in the overall site-selection process.

TABLE 5-2
Overview of Project Details for RCSP Phase III Development Test Highlights

RCSP	Project Name	Project Location	CO_2 Source	Geologic Province	Geologic Setting	Formation Type	Total Injection (tons/CO_2)	Target Depth (ft)	Injection Start Year	Accomplishments
Big Sky	Injection of CO_2 into Moxa Arch	Big Piney, WY	Proposed Cimarex Facility	Moxa Arch LaBarge Platform	Riley Ridge Unit	Saline	1,000,000	11,000	2011	▪ Site selection completed ▪ Site characterization and baseline work underway
MGSC	Large-Volume Sequestration Test: Ethanol Plant Source	Decatur, IL	ADM Ethanol Facility	Illinois Basin	Mt. Simon Sandstone	Saline	1,000,000	6,000 - 7,000	2009	▪ UIC Permit Received 1/2009 ▪ Injection well drilled by 5/2009 ▪ Extensive site characterization conducted ▪ Shallow groundwater wells installed ▪ Pre-injection modeling conducted
MRCSP	Large-Volume Injection: TAME Site	Greenville, OH	TAM Ethanol Plant	Illinois Basin	Mt. Simon Sandstone	Saline	1,000,000	3,300	2010	▪ Pre-injection modeling conducted ▪ Several public outreach meetings have occurred ▪ Site characterization and baseline work underway
PCOR	Williston Basin Demonstration Test	Williston Basin, ND	Basin Electric Power Cooperative's Antelope Valley Station	Williston Basin	Cedar Creek Anticline, Billings Anticline, Nesson Anticline, and Northeast Flank	Oil-bearing	1,000,000	16,000	2010	▪ Site selection underway
PCOR	Ft. Nelson Demonstration Test	Ft. Nelson, BC, Canada	Ft. Nelson Plant	Alberta Basin	Elk Point Carbonate Rock Formation	Saline	6,000,000	5,000	2010	▪ Characterization well drilled and cores collected from caprock and target formation ▪ PCOR teaming with Spectra Energy to develop needed infrastructure: ◦ Acid gas compressors and pumps ◦ Dehydration systems ◦ Pipeline
SECARB	Early Test	Cranfield, MS	Jackson Dome	Tuscaloosa Formation	Strandplain Sandstone	Saline	1,650,000	10,000	2009	▪ Extensive site characterization effort ◦ 100+ logs ◦ Two whole sample cores ◦ Access to 3-D seismic (4-D anticipated) ▪ Began injection 4/2009 ▪ Extensive monitoring program in place and underway ▪ Reservoir modeling
SECARB	Anthropogenic Test	TBD	Southern Company Plant	Tuscaloosa Formation	Strandplain Sandstone	Saline	1,000,000	10000	2011	▪ Plant Berry Site selected for anthropogenic site ▪ Baseline characterization initiated
SWP	Deep Saline Sequestration Test	Uinta Basin, UT or San Juan Basin, NM	To Be Determined	Uinta Basin or San Juan Basin	Navajo, Wingate, and White Rim Formations	Saline	1,000,000	TBD	2011	▪ Site selection underway
WESTCARB	Sequestration of CO_2 from Oxy-combustion	Bakersfield, CA	Clean Energy Systems ZEPP-1	San Joaquin Basin	Vedder Sandstones	Saline	1,000,000	7,000	2011	▪ Site selection completed ▪ Site characterization underway ▪ Development of modeling framework and pre-injection modeling underway ▪ UIC Class V well permit application completed

5.3.5 Beneficial Uses of Carbon Dioxide

5.3.5.1 Introduction

When they are proven and commercially available, the suite of beneficial use technologies currently in the development pipeline could permanently store CO_2 in a manner that is safe, economical, and environmentally acceptable. Moreover, they will not leave future generations with a legacy of CO_2-related issues.

These beneficial use technologies:

- offer a permanent solution to CO_2 storage,
- reduce the volume of material to be disposed,
- mitigate the risk of future leakage,
- generate revenue to offset some capture costs,
- improve the competitiveness of users' products, and
- eliminate CO_2 (and other) emissions and energy consumption associated with manufacturing the alternative materials

One of the major issues facing the nuclear power industry today is long-term waste disposal. Scientists, engineers, politicians and the public have debated the issue for decades (nearly half a century), but there is still no safe, permanent solution. The development and commercialization of the technologies described in this section, and others, will help to achieve CO_2 emission reductions in the decades to come.

Firms who are developing permanent storage or beneficial use technologies that do not involve injection into geologic formations or conversion of CO_2 to fuels include:

- C-Quest: formation of cements and aggregates using the power plant fly ash
- Calera: formation of cements and aggregates from flue gas
- Skyonic: formation of bicarbonate from flue gas
- Greensols: formation of carbonate from flue gas
- Carbon Sciences: formation of mineral carbonates from flue gas
- Novomer: polymers from CO_2
- Carbon Sense Solutions: mineralization; accelerated concrete curing and carbonation using flue gas
- Catelelectric: electrolytic conversion of CO_2 to chemicals
- Mantra: conversion of CO_2 to formic acid
- Carbon 8 Systems: carbonation of industrial waste—atmospheric or with flue gas
- Novacem: atmospheric CO_2 absorbing cement
- Carbonscape: pyrolysis to extract energy and carbon for soil amendment

5.3.5.2 CO_2 Storage in Concrete

The C-Quest technology is characterized by passing flue gas through counter-current treatment vessels with a sorbent that removes pollutants from the gas and captures them in the fly ash which has improved cementitious properties compared to ash collected from untreated flue gas. The development of this technology began in 2005 and two patents were filed in 2006. An additional patent was filed in 2008.

Various pilot trials have been conducted in 2007 and 2008 by the Energy and Environmental Research Center at the University of North Dakota. The testing has focused on sorbent selection and dosage and reactor design. Results achieved to date for various pollutants are shown below.

Pollutant	Capture Rate (%)
CO_2	35-90
NOx	20-55
SO_2	60-100
Hg	40-90

C-Quest is developing its technology to be deployed in a variety of industries--cement, steel and pulped paper, in addition to coal-based power plants. The patents describe the sorbents which are various oxides of calcium, silica, aluminum, iron, sodium, and potassium. The potential advantages of this technology are: 1) conversion of CO_2 into benign, inert materials that can be used in any construction project using concrete, 2) reduction in CO_2 emissions associated with energy or cement production, and 3) multi-pollutant storage in a material that will not leach or release them back into the environment.

The largest technology demonstration in the beneficial use field is Calera Corporation's Carbonate Mineralization by Aqueous Precipitation (CMAP) process. Greensols, Skyonic, Carbon Sense Solutions and Carbon Sciences are other firms that are developing similar processes. Calera Corporation is currently operating a 0.1 MW continuous pilot facility in Moss Landing, California, and is constructing a demonstration facility which will capture the CO_2 from a 50 MW slipstream of a natural gas-fired power generation facility at Moss Landing.

The CMAP process utilizes high pH and aqueous divalent cations such as calcium and magnesium to remove CO_2 from a flue gas stream, convert it into carbonate ion, and precipitate it as a carbonate mineral. The carbonate minerals are precipitated into a form that can be used as a cementitious material. This material is then used to make concrete, or it can be formed into aggregates. These aggregates can also be used in concrete, or as asphalt, road base or in structural fill applications. Aggregates are formed via accelerated lithification, wherein a combination of heat and pressure (and in some cases additional reactive components) is used to cause the minerals to reform themselves from powders into a solid mass.

The precipitation process utilizes divalent cations from seawater, industrial waste such as slag, fly ash or red mud, geologic brine, mafic minerals such as serpentine or olivine, and other sources to combine with carbonate ions to form carbonate mineral precipitates. To precipitate carbonate minerals without the release of CO_2, as often happens in nature, the pH of the solution is elevated utilizing hydroxide ions to form carbonate ions. The hydroxide ions are obtained from alkaline industrial waste such as slag, fly ash or red mud, mafic minerals, or via a revolutionary low-voltage electrochemical base generation technology which is being scaled coincident with the scaling of the aqueous mineral precipitation process.

Flue gas from coal-based power plants is directed into an aqueous contacting system, generally after the fly ash is removed by a baghouse or electrostatic precipitator, wherein the CO_2 is dissolved into the water as carbonic acid, converted to carbonate ion, and precipitated as a carbonate mineral. Waste heat from the flue gas stream is used to dry the precipitate after accelerated gravitational dewatering, or is used to provide heat needed for accelerated lithification into aggregate.

As compared to traditional CCS techniques such as amine absorption, chilled ammonia, etc., the CMAP process has several economic advantages:

- A distinct CO_2 capture and separation step is not required.
- Removal of sulfur compounds to very low levels prior to the process is not required for this process. In fact, the CMAP process removes SOx from the flue gas and obviates the need for scrubbers.
- The overall capital and operating expenditures are expected to be significantly lower.
- The byproduct is a salable product rather than a material which requires transport and geologic injection.
- Formation of aggregate provides a salable product for which there is a market of 3 billion tons/yr in the U.S. (at a 50% captured CO_2 content this provides beneficial re-use of 1/5 billion tons of captured CO_2).
- The process can use solid wastes (fly ash, red mud, slag, etc.) and liquid wastes (brine from oil extraction or desalination) and thereby mitigate other environmental issues.

5.3.5.3 Other Novel Technologies with Longer Development Times

Several developing technologies may also provide productive uses for CO_2 after it is captured. These technologies may require another decade of development, including pilot plant testing and detailed economic reviews that have already been completed for the Calera and C-Quest technologies. However, the development and testing process can be accelerated with increased funding and human resources.

1. Gasoline Production

Sunlight can be captured by solar panels and converted to chemical energy, resulting in CO and O_2 that can then be combined with H_2 to create liquid fuels in the well-known Fischer-Tropsch process, and then converted to gasoline.

2. Magnesite Treatment

CO_2 can also be converted into useful iron oxide and waste in an exothermic reaction resulting from the use of freshly-mined mineral ore, serpentinite or peridotite in a chemical extraction and carbonation process. In addition to the iron oxide which has commercial value, this technology also yields silica which is returned to the mine.

NETL conducted extensive laboratory tests on the development of an industrial process for mineralization of CO_2. These studies focused on an aqueous process using three primary silicate mineral reactants: olivine, serpentine, and wollastonite. While serpentine is by the far the most abundant of these minerals, it is the least reactive in the subject process. Wollastonite is the most reactive, but also the least abundant, thus making olivine the favored silicate mineral reactant, and the focus of the feasibility study conducted for the process. A compilation of the studies conducted on the process, including silicate mineral location and availability, proximity of the mineral reactant to CO_2 point sources (coal-based power plants), process development, and economics, is included in the project

The feasibility study was scaled for the mineral storage of 100% of the CO_2 emissions from a 1.3 GW coal-based power plant. The assumptions and basis for the feasibility study follow:

- Olivine is the mineral reactant, with an ore grade of 100% and MgO concentration of 49% by weight;
- Olivine ore is ground to 80% minus 400 mesh (37 microns);
- 65% reaction efficiency (R_x) with each pass through the process;
- 60% of the unreacted olivine from the products is separated at 20 μm size and recycled;
- Twin Sisters olivine (NW Washington state) is utilized for the process, with the storage facility located next to the mine;
- The mining operation is open pit, and the process products (free silica mixed with magnesium carbonate) are re-deposited in the depleted pits;
- CO_2 is transported to the plant via pipeline from the Centralia, Washington 1,300 MW coal-based power plant (CO_2 separation costs are not included in mineral storage cost estimates);

The NETL study was designed for the storage of approximately 1,100 tons per hour of CO_2, requiring roughly 2,500 tons per hour of virgin olivine ore plus an additional 800 tons per hour of olivine from an unreacted product recycle loop. Power requirements total 352 MW, with nearly 75% of the total power required for the ore grinding operations. This power represents a 27% energy penalty on the power plant for which the storage operation was designed. The overall carbonation costs were $54/ton CO_2 stored, with a CO_2 balance (CO_2 stored – CO_2 generated by the process) of approximately 70%. Thus, the effective cost was about $78/ton CO_2 avoided.

3. Dimethyl Ether

Technology developed MHI has been used by Japan's Kansai Electric Power Company to produce dimethyl ether from CO_2. This substance is commonly used as an aerosol propellant in spray cans. Further research is aimed at improving the chemical process and reducing production costs.

5.3.5.4 Barriers to Widespread Deployment

Beneficial use technologies face both technical and economic hurdles to scale-up and widespread deployment. In many cases, for example, the beneficial use technologies rely on sources of alkalinity from either waste industrial products or from sodium hydroxide. Though there are enormous quantities of waste base sources available, in most instances large scale implementation of beneficial use technologies will require an economical, low carbon footprint source of sodium hydroxide.

The extremely rapid rate of development of beneficial use technologies has outpaced the available funding for scale-up and commercial deployment of the most advanced of these technologies. Without federal funds and related incentives {e.g., tax incentives or qualification as a contribution toward a utility's baseline in any Renewable Electricity Standard, beneficial use technologies will struggle to move to the next stage of commercial viability and large-scale deployment.

6 Legal/Regulatory Issues

Findings

- In order for CCS to be deployed in a safe and timely manner, several legal and regulatory issues must be addressed. The bulk of the needed legal work involves CO_2 injection and storage, with long-term stewardship considerations at storage sites a priority.
- Led by many States and the EPA, an appropriate legal and regulatory framework for CO_2 injection and storage is starting to take shape. The States' roles in CCS regulation should not be underestimated given the successful role that they have played in safely regulating comparable injection and storage activities.
- There are no federal laws governing long-term CO_2 storage. Many States already have adopted comprehensive long-term storage regimes that should be sufficient to enable the permitting of storage operations at early mover CCS projects.
- The DOE must play a leading role in ensuring that CCS is regulated in a manner that protects human health and the environment while enabling worthwhile projects to be financed, developed and operated without unnecessary legal impediments.

Recommendations

- Federal or State governments, or both, must adopt mechanisms by which responsibility for long-term stewardship at storage sites – including both operational responsibilities and liabilities -- is shifted from the private sector to the public sector. Numerous States already have adopted such approaches, and the U.S. Senate has before it bills that would provide a complementary federal role for long-term stewardship.
- CO_2 injection and storage must be subject to stringent, and hopefully unified, permitting under federal and State law.
- Exempting appropriately permitted injection and long-term storage activities from RCRA and CERCLA would be worthwhile because neither statute creates an appropriate regulatory and/or liability regime for geologic injection and storage.
- Congress should clarify the requirements that apply to CO_2 injection and storage on federal lands by, for example, stipulating pore space ownership and amending FLPMA and MLA to explicitly allow long-term CO_2 storage under federal leases.

6.1 Capture of Industrial CO_2

CCS is most likely to be deployed at scale if: 1) the federal government enacts laws or regulations that require industrial facilities to deploy the technology; or 2) the federal government embarks upon a major technology development effort for CCS. The former approach is likely to take the form of emission controls under the federal Clean Air Act (CAA) or emissions caps under new legislation such as cap-and-trade.

6.1.1 Regulation of CO_2 Emissions Under Existing Federal Law

In Massachusetts v. EPA, 549 U.S. 497 (2007), the U. S. Supreme Court held that EPA had authority to regulate GHGs under the CAA if EPA makes an endangerment finding — that is, if EPA finds that GHGs may reasonably be anticipated to endanger public health and welfare. In April 2009, EPA issued a proposed endangerment finding for GHG emissions from motor vehicles (74 Fed. Reg. 18886 (Apr. 24, 2009)). On December 7, 2009, EPA issued its final endangerment finding, a development that will first compel EPA to regulate vehicle emissions of GHGs and may lead to the regulation of GHG emissions from stationary sources.

Regulation of GHG emissions from stationary sources is likely to be addressed under the Prevention of Significant Deterioration program (PSD) and Title V requirements under the CAA. Title V and PSD are triggered when a stationary source emits pollutants that are "subject to regulation" in amounts exceeding certain thresholds.

For CCS purposes, the PSD program holds significant legal interest because of the possible use of CCS as an emissions control technology for stationary sources under the program. The PSD program limits the emission of pollutants "subject to regulation" from stationary sources. It applies to new sources and only applies to existing sources when they are modified in a manner that increases their emission of a pollutant subject to regulation. Most notably, the PSD program requires stationary sources to use the "best available control technology" (BACT) to limit emissions of all pollutants subject to regulation. Determining BACT can be a long, expensive, and source-specific process, and the use of BACT often entails noteworthy capital expenditures and ongoing operation and maintenance costs.

EPA has not yet determined what BACT is for GHGs. EPA's Clean Air Act Advisory Committee currently is examining that issue. For a variety of technical and legal reasons, it is unlikely that CCS would be deemed BACT in the near future. The status of CCS as BACT remains in play, however. The Environmental Appeals Board, in its recent In re Deseret Power decision, remanded to EPA for further consideration a permit for the construction of a new coal-based power plant on the grounds that EPA did not do an adequate job of explaining why IGCC technology was not BACT – and IGCC, of course, could be retrofitted with CO_2 capture technology. It also is possible that CCS could be considered BACT for facilities such as natural gas separation facilities to the extent that they already are engaging in CO_2 separation and EOR.

On September 22, 2009, the EPA Administrator signed a final mandatory GHG emissions reporting rule that may create further drivers for CCS by requiring large industrial sources to report their GHG emissions to a new national registry. Natural sources of CO_2 are included within the rule's scope because EPA wants to track whether CO_2-EOR operators, which predominantly use natural CO_2 today, will start to use increasing volumes of industrial CO_2 in the years ahead as CCS technology is deployed.

EPA also is poised to advance CCS deployment at renewable fuels production facilities as part of phase II of its Renewable Fuel Standard (RFS) program. EPA recently sought comments on whether it would be necessary and appropriate for the RFS program to develop CCS protocols and permanence standards for geologic storage to enable CCS-equipped renewable fuels production facilities to meet the RFS program's new lifecycle carbon emissions requirements.

6.1.2 Federal Legislative Activities

To date, Congress has focused most of its attention to funding, as opposed to regulating or compelling the use of, CCS projects. As a technology that will entail significant costs, particularly for early movers, this attention is welcome. Starting with the Energy Policy Act of 2005 and most recently in the American Reinvestment and Recovery Act of 2009 (ARRA), Congress has provided increasing authorizations and appropriations for technology and site research and CCS deployment. A large portion of the $3.4 billion that Congress provided DOE's Office of Fossil Energy under the ARRA was intended for CCS-related programs.

Congress has enacted tax incentives for CCS-related activities, too. The Energy Improvement and Extension Act of 2008 (EIEA) made pipelines transporting industrial CO_2 eligible for Master Limited Partnership tax treatment under the U.S. Internal Revenue Code. And section 45Q of the Code, enacted by EIEA and later amended by ARRA to add a "secure geologic storage" requirement to CO_2-EOR operations, provides a $10/ton and $20/ton tax credit for CCS in CO_2-EOR and deep saline, respectively. The U.S. Internal Revenue Service recently published guidance for taxpayers seeking to claim the 45Q credit.

Despite Congress' current focus on funding and incentives, legislation that would impose carbon management requirements on coal-based facilities is pending. Congress continues to debate bills that would regulate industrial emissions of GHGs through mechanisms such as cap-and-trade. Enactment of a federal cap-and-trade bill likely would provide additional funding for CCS – through mechanisms such as CCS bonus allowances and wire charges – and create legal requirements that major industrial sources would be subject to when they deployed the technology.

On June 26, 2009, the House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009, which would create a national cap-and-trade program. Various U.S. Senate committees are now considering their own versions of H.R. 2454, with the lead legislative vehicle in the Senate being S. 1733, the Clean Energy Jobs and American Power Act, which Senators Kerry (D-MA) and Boxer (D-CA) introduced on September 30, 2009.

With respect to CCS, H.R. 2454 and S. 1733 have several elements in common, including: 1) legal recognition that CCS is a carbon management technology; 2) billions of dollars in CCS bonus allowances for early-mover CCS projects; 3) mechanisms to fund CCS demonstration projects, such as the so-called Boucher wires charge approach that would generate approximately $10 billion over ten years for such purposes; and 4) amendments to the CAA to create new source performance standards for coal-based fired units that would effectively impose CCS deployment mandates over the coming decade.

6.1.3 State Developments

The States are separately encouraging, or effectively requiring in some instances, the deployment of CCS technology. Most notable among these may be California's cap-and-trade program, known as AB32. AB32 commits California to reduce GHG emissions to 1990 levels by the year 2020, with the ultimate goal of achieving a 90% reduction from 1990 levels by 2050. CCS is anticipated to have legal status under AB32 because, for example, the California Air Resources Board has identified a CCS compliance pathway for fuel producers and refiners under California's Low Carbon Fuel Standard (LCFS).

Several States also have enacted novel financing programs for clean-coal infrastructure outside of the context of cap-and-trade. Illinois' clean coal portfolio standard encourages the development of CCS-equipped clean-coal projects. North Dakota, Texas and Utah have adopted their own forms of incentive legislation for CCS infrastructure projects. In the years ahead, other States likely will adopt their own approaches to attract clean-coal and related CCS infrastructure as a matter of economic development, job creation, and environmental improvement.

6.1.4 Canadian Considerations

CCS developments in Canada are anticipated to influence the legal status of CCS in the U.S. It is possible that U.S. regulators shortly will acknowledge as a legal matter CCS activities in Alberta, Canada associated with the oil sands production process. As noted above, the LCFS already indicates that Alberta-based CCS will be suitable for compliance purposes in California.

Section 526 of the Energy Independence and Security Act of 2007, which prohibits the U.S. Department of Defense and other federal agencies from purchasing non-conventional fuels that have higher lifecycle GHG emissions than conventional petroleum, is expected to create similar legal results – i.e., any Alberta-based operator that is deploying CCS would presumably be able to show, on a case-by-case basis, that it was in compliance with section 526.

While these cross-border developments would not have a direct impact on CCS-based projects in the U.S., they should carry with them an imprimatur of legal status for CCS generally that could be helpful for U.S. coal-based facilities.

6.1.5 Judicial Developments

A growing impetus for CCS may continue to emerge from litigation. In State of Connecticut v. American Electric Power, __ F.3d __ (2nd Cir. Sept. 21, 2009), the U.S. Court of Appeals for the Second Circuit authorized a lawsuit under the federal common law of nuisance against major emitters of GHGs, the first federal appellate decision to do so. That decision was followed shortly thereafter by Comer v. Murphy Oil USA, Inc., __F.3d__ (5th Cir. Oct. 16, 2009), in which the U.S. Court of Appeals for the Fifth Circuit decided that private parties could pursue public nuisance claims against the chemical, oil and gas, and utility industries for damages caused by Hurricane Katrina that the plaintiffs alleged were caused or exacerbated by industrial emissions of CO_2.

While it is difficult to connect the dots between these decisions and the possible future deployment of CCS by a coal-based electric utility, at minimum the former provides impetus to the further development of carbon management technologies such as CCS.

6.2 Pipeline Transportation

Widespread deployment of CCS could result in the creation of a CCS pipeline network that some have estimated may span between 15,000 and 66,000 miles, the upper range of which is nearly as large as the existing natural gas pipeline network in the U.S.[i] The U.S. today has a 3,600-mile natural CO_2 pipeline network. This puts the potential size of the task in perspective.

It is important to keep in mind that not all of this new infrastructure needs to be built at once. Moreover, in terms of siting, safety and rate regulation, the existing U.S. CO_2 pipeline network operates quite well. That network also crosses State boundaries, which suggests that a federal role based upon interstate commerce needs may not be necessary, at least not yet.

Ultimately, the extent of the future CO_2 pipeline network will depend not only on how widespread is the deployment of CCS, but also such factors as the viability of potential geologic storage formations in various areas, the timing of CCS deployment, the economics of pipeline construction and operations, and where future coal-based facilities will be located.

There are four key issues with the development of a CCS pipeline network: 1) siting; 2) rate regulation; 3) safety regulation; and 4) special considerations related to using CO_2-EOR pipelines for CCS.

6.2.1 Siting

Siting pipelines poses two key sets of legal issues: compliance with statutes requiring reviews of environmental, cultural, and historic resource impacts; and whether eminent domain authority is available when private property is needed to serve a public purpose. The latter could be a significant impediment to constructing CO_2 pipelines, as without the availability of such authority, agreements would have to be reached with landowners through private means, and any individual landowner may be able to block construction of a needed pipeline.

In recent years, particularly through the Energy Policy Act of 2005, Congress has sought to ease siting burdens for energy infrastructure related to both issues. With focus increasing on CCS development, at the appropriate time DOE should consider supporting similar policy advances with respect to CO_2 pipelines.

6.2.1.1 Eminent Domain Authority

Either States or Congress could make eminent domain authority available for construction of CO_2 pipelines. Under some circumstances, eminent domain authority already is available under State law for this purpose (Oklahoma and South Dakota, for example). The Interstate Oil & Gas Commission (IOGCC) is anticipated to release further legislative recommendations to the States on this topic in 2010.

6.2.1.2 State Eminent Domain Authority

In most of the States, it is not clear whether an entity constructing a CO_2 pipeline may obtain a certificate of convenience and necessity, and whether eminent domain authority would be available to construct such a facility.

Were a CCS pipeline being constructed with a desire to access State eminent domain authority, there are several key issues to be considered, such as: 1) nature of the pipeline applicant – i.e., eligibility may be limited to companies that have service territories, which are unlikely to include pipelines companies; 2) in-State benefits – i.e., the pipeline applicant may have difficult showing that the infrastructure benefits in-State consumers; 3) what facilities are being constructed – i.e., States limit eminent domain to specific classes of infrastructure which may or may not include CO_2 pipelines under current State law; and 4) will the pipeline have a public use – i.e., non-common carrier pipelines may be excluded from the State regulatory scheme.

6.2.1.3 Federal Eminent Domain Authority

For CO_2 pipeline purposes, an example of federal eminent domain authority is Section 7 of the Natural Gas Act of 1938. Congress recognized at an early time that there would be an interstate natural gas pipeline network and accordingly provided eminent domain authority. Parties constructing interstate natural gas pipelines must obtain from FERC a certificate of convenience and necessity, which carries with it the ability to exercise eminent domain authority, should an applicant be unable to arrange reasonable terms to cross a landowner's property. While this section has not been without implementation difficulties, it may provide a useful model for CO_2 pipelines that the DOE should support in federal legislation at the appropriate moment if and when circumstances dictate that result.

6.2.1.4 Environmental, Cultural, and Historical Reviews

At the federal level, the siting of pipelines most often raises issues under the Clean Water Act, the Rivers and Harbors Act of 1899, NEPA, and the Endangered Species Act. Any number of other federal statutes may apply, depending upon the resources affected by or near the pipeline. Application of these statutes on a case-by-case basis typically is time-consuming and cumbersome. However, they are not expected to create disparate hurdles for CO_2 pipelines in comparison with other forms of infrastructure projects.

6.2.1.5 Siting on Federal Lands

CO_2 pipelines that pass through federal lands managed by the Bureau of Land Management (BLM) may be sited under right-of-way provisions of either the FLPMA or the MLA. The MLA imposes a "common carrier" requirement while the FLPMA does not.

The MLA currently permits CO_2 pipelines for EOR under the MLA. Today, the BLM permits CO_2 pipelines for EOR in a manner that implicitly treats CO_2 as a "commodity" and not as a "pollutant." However, BLM permitting of CO_2 pipelines for non-CO_2-EOR purposes may necessitate a statutory change to require common carriage. Also, renegotiation of expiring pipeline rights-of-way across Indian lands is becoming increasingly difficult, with tribes demanding significant concessions. Federal eminent domain powers are typically not applicable on such lands.

Section 368 of the Energy Policy Act of 2005 directs various federal departments to coordinate the designation of corridors for certain energy-related facilities across federal lands. CO_2 pipelines are not explicitly covered, though they could make use of corridors designated for other energy infrastructure.

6.2.2 Rate Regulation

Although an interstate CO_2 pipeline arguably falls within the regulatory jurisdiction of the U.S. Surface Transportation Board (STB), an independent federal agency affiliated with the U.S. Department of Transportation (DOT), STB rate oversight is very limited compared to FERC regulation of natural gas and oil pipelines.

Interstate CO_2 pipeline operators may set their own rates and service practices without the requirement that they be filed with the STB. Though the STB ensures that rates are reasonable and nondiscriminatory, a rate proceeding or investigation begins only in response to a third-party complaint filed against a pipeline operator.

6.2.3 Safety Regulation

CO_2 pipeline safety currently is regulated by DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) under the Hazardous Liquid Pipeline Act of 1979. The regulator is PHMSA's Office of Pipeline Safety (OPS). OPS regulations define "carbon dioxide" as a "fluid consisting of more than 90 percent CO_2 molecules compressed to a supercritical state." Although these provisions are tucked within the same provisions that apply to pipelines carrying hazardous liquids, the regulations make clear that CO_2 is nonhazardous.

These safety regulations have functioned well for decades and no changes to them are anticipated in the early years of CCS deployment, at least to the extent that injected CO_2 meets the definition of "carbon dioxide," which is likely to be the case. To the extent that changes are necessary, OPS is well equipped to implement and enforce them. The safety record of natural CO_2 pipelines under OPS' current regulatory regime is well-documented.[ii]

6.2.4 Special Considerations Regarding the Use of CO_2-EOR Pipelines for Transport of CO_2 for Long-Term Storage

It is important that regulators be cognizant of the differences among pipelines used: 1) solely for CO_2-EOR; 2) solely for CCS; and 3) for both CO_2-EOR and CCS[iii] CO_2-EOR pipelines are sized, sited and regulated to deliver the minimum amount of CO_2 to downstream customers for purposes of oil recovery. In contrast, a CCS pipeline presumably would be sized, sited and regulated to accept maximum amounts of CO_2 from upstream customers. Pipelines serving both downstream CO_2-EOR customers and upstream CCS customers, which may be the case with early-mover CCS infrastructure, may thus be in the position of trying to satisfy different, and perhaps conflicting, policy goals.

6.3 Geologic Storage

Some of the most challenging legal issues associated with CCS are expected to involve the geologic storage of CO_2. These issues may be divided into seven categories: 1) CO_2 quality specifications; 2) injection regulation; 3) pore space rights; 4) long-term storage regulations; 5) long-term stewardship considerations; 6) protocols; and 7) carbon credit considerations.

6.3.1 CO_2 Quality Specifications

At some point in the future, regulators and industry may have to develop different CO_2 quality standards depending upon the nature of the geologic formation into which the injection and storage occurs.iv For example, CO_2-EOR operators who may face formation-specific limits (or requirements) as to what may be co-injected with the CO_2.

Formation-specific requirements of this nature exist for natural CO_2-EOR operations but, at present, there are no industry-wide standards that would apply more generally for industrial CO_2 storage operations. The absence of such standards is not an impediment for the development of CCS today, but it is an issue that may have to be addressed in the years ahead.

6.3.2 Regulation of Injection

Regulation of injection of industrial CO_2 for storage purposes is currently proceeding on two fronts. First, many States have adopted laws that call for issuance of such regulations. At least one State – Washington – already has issued its regulations, while another – Kansas – is in the midst of its rulemaking. These States and others following in their footsteps are either adopting their own programs or creating regulatory schemes that will be folded into or subject to a future federal injection program.

A federal regulatory program for CO_2 injection wells is emerging. On June 25, 2008, EPA published a proposed rule under the SDWA's UIC program that would create a new well classification – Class VI – for CCS wells. Class VI would resemble Class I, which typically is used for hazardous waste injections.

It is significant and helpful that EPA is developing a CO_2 injection well rule but the approach being followed could lead to unintended consequences. For example, as proposed, the rule might inadvertently hinder the use of CO_2-EOR as CCS. The rule might also prohibit injections above the lowermost drinking water aquifer, which could eliminate some regions of the U.S. from CCS entirely.[v] It remains unclear if the rule will allow the States primacy to enforce the new Class VI well requirements, a development that would run counter to the groundbreaking work that the States have already done in establishing their own injection well programs.

Perhaps the most significant concern is EPA's position that RCRA and CERCLA would apply to injected CO_2 unless the injected CO_2 was effectively pharmaceutical grade or otherwise pure, which is unlikely to be the case with CO_2 captured from industrial facilities.

Imposition of RCRA and CERCLA liabilities could complicate CCS by creating a legal impediment to project development. EPA's position on these matters runs counter to that of at least some of the States – North Dakota, for example, has declared in legislation that industrial CO_2 when injected for storage is not a pollutant and does not constitute a nuisance.

6.3.2.1 Legal Implications of Application of RCRA to CO_2 Injection

RCRA provides cradle-to-grave management for the treatment, transportation, storage, and disposal of solid and hazardous wastes. RCRA defines a "solid waste" as, among other things, "discarded material, including . . . liquid or contained gaseous material resulting from industrial . . . operations," and thus would potentially include CO_2 in a semi-critical state. A "hazardous waste" is "a solid waste . . . which, because of its quantity, concentration, or physical, chemical, or infectious characteristics may . . . pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed." Hazardous wastes are either "listed" (i.e., wastes that EPA has specifically identified as hazardous) or "characteristic" (i.e., wastes considered to be hazardous because they meet the above definition and are ignitable, corrosive, reactive, or toxic).

A CO_2 injection or storage facility that is deemed to engage in hazardous waste injection could be regulated under the rules for UIC Class I hazardous waste wells, not the proposed new Class VI requirements. A major problem with this is that the "no migration" standard for Class I wells would apply. This standard has been applied to mean that a site operator must show there will be no migration of non-treated hazardous wastes for 10,000 years. This would be a significant impediment for CO_2 injection sites, given the volumes expected to be handled.

A further issue is that if a unit of a facility is subject to hazardous waste requirements, other waste management units at the site become subject to RCRA corrective action requirements, which are costly and burdensome. This would be a consideration, for example, if an injection site were located at an electric power plant.

6.3.2.2 Legal Implications of Application of CERCLA to CO_2 Injection

Superfund is a liability scheme, rather than a regulatory scheme, that provides for joint, strict, and several liability for the "release" of a "hazardous substance." A hazardous substance is defined by the so-called "list of lists" – i.e., if a substance is regulated or controlled under one of a number of other federal statutes, it is a hazardous substance under Superfund.

The term "hazardous substance" must be considered not only with respect to CO_2, but also with respect to other constituencies in the injectate, even if present only in small concentrations. The term also may be applicable to subsurface materials that mix with or are mobilized by the injectate. That is, Superfund potentially could apply in the CO_2 injection and storage context regardless of whether CO_2 is considered to be a hazardous substance, pollutant or contaminant.

Superfund also provides that the federal government may respond in cases of "an imminent and substantial danger to the public health or welfare" caused by release of a "pollutant or contaminant." A pollutant or contaminant is defined very broadly and likely could include releases of CO_2 today, if they are deemed to pose an imminent and substantial danger. The federal government may sue responsible parties to recoup costs incurred by the government for the response.

CERCLA does not apply to a "federally permitted release." However, that exception likely would not apply in cases where CO_2 accidentally has leaked from the storage site and caused damage. This is because the exemption only applies for actions within the four corners of a permit, and an accident (which potentially would include plume migration), of course, would be an unpermitted event. The courts have interpreted this exemption narrowly, too.

Injection of industrial CO_2 for concurrent EOR and long-term storage may also subject the oil field operator to Superfund liability.

6.3.3 Pore Space Rights

Pore space rights – i.e., the legal right to inject industrial CO_2 into a pore space and store it there indefinitely – are rapidly being addressed by the States, a trend that is expected to continue as property rights on private lands in the U.S. remain a topic of nearly exclusive State concern. Both North Dakota and Wyoming, for example, have adopted pore space bills; North Dakota even allows unitization of storage rights. Similar legislation is pending in New York. The Texas legislature is expected to consider comparable legislation in the near future. Other States, such as Illinois and West Virginia, are anticipated to follow suit.

The rule which is emerging from these State enactments is that pore space is owned by the surface estate. The surface estate owner may sever the pore space through an appropriate legal conveyance that is recorded in the public records. The mineral estate is dominant over the pore space.

Despite State leadership in this area, challenges regarding pore space ownership are expected to emerge in the years ahead, resolution to which may require further State legislative enactments or litigation to resolve. Key among these challenges are: 1) ownership of pore space in active CO_2-EOR floods under mineral leases that are silent on the topic; 2) status of injected industrial CO_2 at the completion of an CO_2-EOR flood and expiration or termination of a mineral lease; and 3) possible application of unitization statutes, which allow the consolidation of mineral interests in some circumstances in some States, to pore space rights.

A final challenge is ownership of pore space in deep saline formations in those States that have not yet enacted pore space laws. The brine in deep aquifers is classified as "percolating water" (i.e., water that does not flow along a defined bed, like an underground river). Rivers and streams are the property of the State but ownership of percolating water depends on the applicable property regime followed in each State. There are at least five different property regimes covering percolating waters -- Absolute Dominion, Reasonable Use, Correlative Rights, Restatement Rule, Prior Appropriation and combinations of these regimes. Application of these regimes could result in different outcomes in different States, a scenario which could in theory complicate deep saline injections that cross State lines. To the extent that these difficulties crop up down the road, they are not amenable to a federal solution in any event.

6.3.4 Regulation of Long-Term Geologic Storage of Industrial CO_2

There is no federal comprehensive regulatory regime for the long-term geologic storage of CO_2, although it is possible that EPA will propose such regulations to accomplish that goal under the CAA in the near future.

The States, however, are moving diligently to adopt comprehensive storage regulatory schemes. The following States have adopted legislation that calls for appropriate State regulators to issue such regulations: Connecticut, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas and Wyoming. These States generally are following the approach set forth in the IOGCC's model injection and storage rules, a trend that is expected to continue.

These State approaches generally contain the following attributes: 1) definition of key terms; 2) deference to EPA's forthcoming UIC rules regarding regulation of injection; 3) comprehensive storage siting requirements and restrictions; 4) public notice and comment; 5) permit issuance; 6) reporting and recordkeeping; and 7) use of appropriate measuring, monitoring, and verification technology.

In the future, a federal supervisory role in the permitting of storage may be advantageous due to interstate considerations. Such a federal role might be based under an enhanced SDWA that covered storage as well as injection, with appropriate permitting authorities delegated to the States.

6.3.5 Long-Term Stewardship of Geologically Stored CO_2

Long-term stewardship of geologically stored CO_2 refers to the following legal issue – who is responsible for stored CO_2 given that storage must, in theory, occur indefinitely?

6.3.5.1 What are the Potential Liabilities?

For well-sited and operated geologic storage facilities, CO_2 injection and storage is expected to pose minimal risks to human health and the environment, according to numerous experts such as the Intergovernmental Panel on Climate Change. In the absence of legislative changes, CO_2 injection and storage operations nonetheless will be conducted in the context of a litigious American legal system which could impose a variety of liabilities on even the most well-sited and well-managed projects.

Some of these liabilities may arise under statutes such as RCRA and CERCLA, as discussed above. Other potential liabilities are discussed separately below.

Trespass. Two primary risks associated with the siting of CO_2 injection and storage projects are surface and subsurface trespass. Surface trespass might occur, for example, in site testing and monitoring and verification activities. Subsurface trespass involves underground migration of injected CO_2 into areas where property interests have not been acquired, as well as from waves shot for 3-D seismic mapping. It also involves the migration of displaced fluids or other underground materials into another's property.

Commingling or "confusion" of goods is another subsurface trespass concern for CO_2 injection and storage operations. Injected CO_2 potentially can migrate from the injection site to the subsurface area of an adjoining landowner. The operation of wells in compliance with permits will not necessarily insulate the operator from liability for trespass from adjacent subsurface owners. In several cases, actions for subsurface trespass were allowed in connection with "fracturing" (hydraulic fracturing to increase permeability). Yet, other cases have applied the "negative rule of capture" to disallow nuisance suits associated with the migration of injected liquids, a rule widely accepted by legal scholars. This rule holds that, just as under the rule of capture a landowner may "capture" oil or gas that migrates under his land, a landowner can inject substances which "may migrate through the structure to the land of others."

Liability for confusion of goods occurs when different persons' goods are intermixed so that the property of each can no longer be distinguished. An example might be the intermixing of injected CO_2 with native gas in a reservoir where the full property interests have not been obtained. Where substances are deemed willfully, fraudulently or wrongfully inseparably intermingled, the person forfeits his right in the goods to the innocent party. This would be determined on a case-by-case basis.

Unitization rules frequently used for oil and gas development and in secondary oil recovery operations could be a useful tool to protect against trespass suits, particularly in large-scale CO_2 storage projects. Many oil and gas producing States have "compulsory joinder of interest" for mineral extraction once a certain percentage of owners agree to field unitization.

Ownership of Migrated CO_2. The issue of who will own CO_2 that has migrated under the land of an adjoining subsurface owner may have an analogy in natural gas and oil precedents. The early courts applied the "wild beast" analogy to fugacious oil and gas. This led to the "non-ownership" theory of oil and gas resources under which the subsurface owner did not possess the oil and gas until it had been captured. A Kentucky court applied the non-ownership theory to gas injected into a storage reservoir, but later cases rejected application of this rule to stored natural gas. Most States now follow the "ownership in place" theory, giving the mineral rights owner a "possessory estate" to oil and gas injected in defined storage reservoirs. But the "rule of capture" continues to apply to gas that migrates under an adjoining landowner's property. A legal question arises as to whether the "rule of capture" analogy is appropriate for industrial CO_2 since that CO_2 was never "wild" (i.e., naturally occurring).

Where goods are intermingled (e.g., natural gas and CO_2 or CO_2 from one storage site commingled with CO_2 from an adjacent storage site), ownership of the intermingled good will depend on being able to distinguish the goods.

Nuisance. Another potential private cause of action could be on grounds of nuisance. Plaintiffs may include subsurface owners. The difference between a trespass and a nuisance claim is that a trespass claim involves actual intentional physical invasion of the plaintiff's property, while nuisance arises from the substantial interference of the use and enjoyment of the plaintiff's property. Nuisance claims have been confronted in the subsurface injection context, for example, when salt water injected for secondary oil recovery contaminated a private drinking well.[vi] In a CO_2 storage context, a nuisance claim might be that the injected CO_2 has migrated into a private groundwater supply and caused its carbonation, the carbonation having interfered with the use and enjoyment of the resource. This is usually remedied through an injunction, forbidding a party from taking an action such as continued injection, and payment of damages.

Negligence and Strict Liability. Another potential cause of action is negligence, which cause comprises the bulk of tort litigation. Like trespass and nuisance, a negligence claim might address harm to property and the environment. In addition, it could be used to provide a recovery for the effects of CO_2 leakage on human health. Actionable negligence involves a legal duty on the part of a reasonably prudent person to use due care, a breach of such legal duty, and the breach as the proximate or legal cause of the resulting injury. In a CO_2 storage contest, plaintiffs, to be successful, would have to show that the storage operator had a duty of reasonable care over the storage operation, that the operator breached that duty by his unreasonable conduct, and that harm was caused to the plaintiff as a result, such as damage to plaintiff's health, contamination of subsurface minerals, or harm to surface property. With respect to property claims, remedies could center on damage to the subsurface minerals or to property, such as diminution in value or costs of restoration.

There is the potential as well that CO_2 storage could be subject to strict liability, where the cause of action against the defendant is based upon an absolute duty to make something safe. It is different from negligence, however, in that a finding of strict liability does not depend on the level of care exercised by the defendant. If CO_2 storage were deemed to be "abnormally dangerous," plaintiffs, in order to recover damages, would only need to show harm and that a causal connection existed between the CO_2 storage and the injury. In other words, if strict liability were to apply, even the most careful and proper conduct by the site owner and operator still could result in liability in the case of an accidental release.

6.3.5.2 Mechanisms to Address Potential Liabilities During Operational and Post-Injection Site Care Phases of Storage Operations

Mechanisms, however imperfect, appear to exist to address potential liabilities during the operational and post-injection site care phases of storage operations.

At present, there is only one insurance product for the operational and site care phases of a long-term storage operation; the operational phase consists of active injections and the site-care phase consists of post-injection monitoring and related tasks to ensure plume stabilization in accordance with site models. Insuring risk at a complex industrial facility calls for a specialty risk product, not ordinary property and casualty coverage. While only one insurer has publicly entered the market, few others would be likely to do so. Only four or five insurers offer products for environmental risks.

One issue for consideration is how to address potential liabilities during the operation and site care phases that may exceed the amount of coverage required by regulators and provided under insurance or another mechanism. Policy makers should consider whether it would be appropriate to provide a mechanism to address such liabilities in an orderly fashion, rather than leave companies providing public services open to potentially crippling risks.

Financial assurance is another mechanism. These requirements consist of bonds, insurance, corporate guarantees, self-insurance, letters of credit, trust funds, or other mechanisms that are approved by regulators. By their terms, such mechanisms spell out the circumstances under which the risk management product is available, to whom it is payable, and up to what amount. Some also require renewal, and could become unavailable before the expected end of the injection or site care period.

Finally, self-insurance may be an option, particularly for well-capitalized companies.

6.3.5.3 Mechanisms to Address Potential Liabilities During The Long-Term Stewardship Phase of Storage Operations

Mechanisms to address potential liabilities during the long-term stewardship phase of storage operations are needed but, unfortunately, are unavailable today.

Long-term stewardship risks at CO_2 injection and storage facilities are expected to diminish over time as the CO_2 -- via various processes such as physical trapping beneath a confining zone, capillary action in pore space, dissolution in saline aquifers, and transformation via chemical processes into carbonates -- becomes trapped and stabilized. Nevertheless, some level of risk, anticipated at properly selected sites to be minute, will continue into the long-term stewardship phase of site operations. Some entity must be responsible for that risk.

No private entity has yet expressed a willingness to accept long-term stewardship after the operation and site care phases have ended. Depending on the capacity of the site and the duration of the site care period established by regulators, it is not out of the question that the facility owner or operator may be liable for the site for 100 years or more. No insurance company is offering a product to cover this period, and corporations – themselves subject to limited lifetimes, shareholder considerations and the like – are almost certainly unable or unwilling to self-insure for this period. And even if carrying such risks on the balance sheet were feasible, that approach may be unacceptable to regulators and the public.

The long-term storage of CO_2 thus presents a logical circumstance for government assumption of long-term risks at storage sites. This is because long-term storage serves goals in the public interest that the government deems essential: reducing atmospheric release of a GHG while preserving the viability of an affordable and plentiful domestic energy resource and minimizing cost impacts to consumers.

Several States have agreed to play some role in assuming long-term risks at storage sites at a defined period of time after injection operations have ceased and the site has been issued a certificate of closure by the applicable regulator. States following this approach, in whole or in part, include Louisiana, Montana, North Dakota, Oklahoma and Texas. Additional States are expected to follow suit in the months and years ahead.

Two models for addressing long-term stewardship also have emerged at the federal level. The first is S. 1462, the American Clean Energy Leadership Act of 2009, which passed the Senate Committee on Energy & Natural Resources in mid 2009. S. 1462 provides a mechanism by which DOE may provide indemnity for long-term storage liabilities associated with up to ten CCS demonstration projects. It establishes a trust fund, capitalized by fees paid by participants, to pay for site care, monitoring, and remediation for which the government would be responsible during the long-term phase.

S. 1462 is a beneficial step. However, its usefulness is limited not only by the fact that it applies only to ten demonstration projects, but also by provisions that would result in the project applicant not knowing perhaps until the project is in the long-term phase whether indemnity will be provided. Financial assistance applicants must agree to comply with post-injection site care and site closure requirements, including making a series of showings for ten consecutive years after the injectate plume has stabilized, which is not likely to occur until possibly well after injection has ceased.

The second is S. 1502, the Carbon Storage Stewardship Trust Fund Act of 2009. S. 1502 assigns responsibility for long-term liability at CO_2 storage sites to the federal government, and thus is broader in scope than S. 1462. Like S. 1462, S. 1502 establishes a fee based on the number of tons of CO_2 injected at storage sites. Fees collected are to be held in trust to pay costs during the long-term phase for site care, monitoring, and remediation. S. 1502 provides site developers, investors, and risk managers with the up-front knowledge that long-term site responsibility will be addressed.

Policy experts can debate the pros and cons of specific long-term stewardship mechanisms and whether this topic is a matter of federal or State attention – or both. What is important is that an acceptable mechanism be implemented to shift long-term stewardship obligations from the private sector to the public sector at a point in time after the operational and post-injection site care phases of CCS are completed.

6.3.6 CCS Protocol

In order for CCS to be deployed commercially in the U.S., industry – with the support of appropriate government regulators – will need to develop a workable CCS protocol that vets and assigns CO_2-related legal rights and obligations throughout the CCS industrial chain, from sources to pipelines to sinks. Jurisdictions in which CCS already has regulatory status, such as Alberta, Canada, have such protocols in place. A nascent effort to develop a suitable CCS protocol for use in the U.S. is already underway and should be supported by DOE.

6.3.7 CO_2 Credit Considerations

DOE should support the use of CCS as a CO_2 credit opportunity in both voluntary and regulated markets because doing so would provide project developers and investors with additional incentives to advance worthwhile CCS infrastructure projects. In the event that Congress enacts a cap-and-trade program, for example, it will be important for the federal government to ensure that CCS qualifies for whatever credits may be available.

[i] Developing A Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges (Interstate Natural Gas Association of America, Fed. 2009).
[ii] From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage, P. Marston & P. Moore, 29 Energy L. J. 421, 450 (2008).
[iii] Id., 29 Energy L. J. at 463-466.
[iv] Id., 29 Energy L. J. at 488.
[v] In a Notice of Data Availability published on August 31, 2009 (74 Fed. Reg. 44802), [vi] EPA stated that it is considering a waiver process under the proposed rule to allow injections above the lowermost drinking water aquifer on a case-by-case basis.
[vii] See, e.g., Gulf Oil Corp. v. Hughes, 371 P. 2d 81, 82 (Okla. 1962).

7 Coal Beneficiation Reduces CO_2 Emissions from the Overall Coal-to-Electricity Process

Findings

- Coal beneficiation technologies improve the quality of coal by reducing its ash and moisture contents, and help to achieve the President's goal by reducing CO_2 emissions from the transportation and handling of coal.
- The use of beneficiated coal improves the efficiency of power generation, thereby lowering emissions of CO_2.
- The use of beneficiated coal results in a simultaneous reduction in multiple emissions, including CO_2.
- Coal beneficiation technologies are compatible with the existing coal-based generating fleet, regardless of age, type of boiler, emission control equipment, fuel type or location.

Recommendations

- The Council recommends that the DOE ensure that coal-based units receive credit for CO_2 emission reductions achieved through the use of beneficiated coal technologies.
- The Council proposes that DOE open up a funding solicitation under the CCPI or through EPAct 2005's Loan Guarantee Program, focused on the accelerated development and commercial deployment of coal beneficiation technologies.

7.1 Introduction

Opportunities exist *today* to generate economically viable reductions in a wide range of emissions, including CO_2, using coal beneficiation technologies. Numerous processes are in operation or under development to treat coal prior to its use, making it a cleaner, more efficient fuel. These technologies produce enhanced fuels that result in lower emissions of SO_2, NOx, Hg and CO_2. When used in combination with other combustion and post-combustion emission control technologies, the environmental and cost benefits are manifold. Many of these proven technologies are currently installed at commercial-scale operations worldwide.

7.2 Coal Beneficiation Technologies for Emission Control

There is no single universal technology for addressing emissions of criteria pollutants and CO_2 for all coal-based power plants. While there are numerous technology solutions that can be applied to the nearly 50 GW[11] of new coal-based power plants currently planned or announced for future development, not all of them are suitable for retrofitting the existing coal-based generating fleet. To effectively reduce CO_2 emissions, technologies that can manage emissions from conventional plants will be needed, including coal beneficiation technologies.

An improved understanding of the interplay between coal quality and boiler performance can lead to increases in boiler efficiency at low cost. Higher efficiency means using less coal to generate the same amount of electricity, thereby reducing the emissions of CO_2. Recent studies conducted by EPRI and CURC indicate that for each 1% increase in combustion efficiency there is a 2.5% reduction in CO_2 emissions from coal-based power plants. By applying these technologies, other emissions can also be reduced. Depending on the specific beneficiation technology employed and the coal being used, emissions of mercury can be reduced from 15-90%; NOx can be reduced by 10-50%, and SO_2 reductions of 10-80% can be achieved.

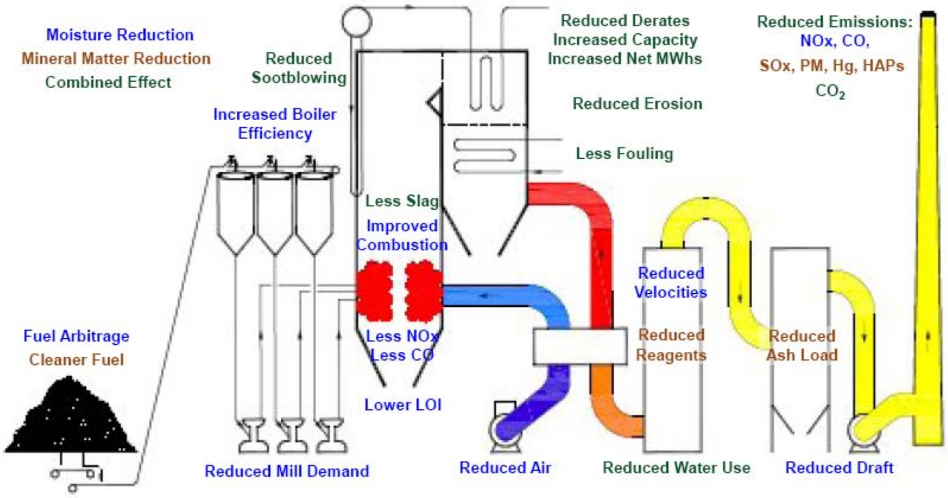
The potential for improved efficiency is especially high in cases in which a boiler that is using an off-design fuel is switched to an optimally-specified fuel. Using a higher quality coal can yield benefits such as:

- Reduced fuel consumption
- Decreased emissions
- Reduced production of coal combustion byproducts
- Reduced maintenance
- Increased plant availability

These advantages and more are shown in Figure 7-1.

[11] National Energy Technology Laboratory, U.S. Department of Energy, "Tracking New Coal-Fired Power Plants," June 23, 2009.

FIGURE 7-1
Benefits of Coal Beneficiation on Coal-based Power Generation



Source: SynCoal Solutions

Coal beneficiation technologies generally involve modifying a coal's characteristics prior to combustion to achieve improved energy conversion efficiency and environmental performance in existing and new coal-based units. The types of enhancements made to the coal fall into three categories: 1) coal preparation, 2) coal upgrading/drying, and 3) coal treatment.

7.2.1 Coal Preparation

Coal preparation is the most widely used form of coal beneficiation. The following three technologies are used for cleaning coal prior to combustion:

- Wet cleaning
- Dry cleaning
  - Chemical or microbial cleaning

Cleaned coal contains significantly less ash than raw coal and, when combusted, results in lower SO_2 and Hg emissions because the cleaning process removes sulfur and mercury bearing minerals associated with the coal. By producing a higher quality fuel product, plants that burn cleaned coal experience improved fuel combustion performance, resulting in increased efficiency and reduced NOx and CO_2 emissions. To the extent that waste coal is used for feedstock into the coal preparation plants, additional environmental benefits result from the recovery and reclamation of a previously unused resource.

7.2.2 Coal Upgrading/Drying

Coal upgrading technologies primarily remove moisture from lower-ranked coals, thus increasing the energy density (i.e., Btu/lb) of the enhanced product. These technologies fall into four groups:

- Direct heat – contacting the coal directly with hot gas to remove moisture
- Indirect heat – heating other media or materials which in turn heats the coal to remove moisture
- Briquetting – using heat and pressure to physically drive off the moisture contained in the coal
- Electromagnetic energy – which excites the water molecules in the coal, heating them and driving them from the coal

Driving off much of coal's moisture enhances its combustion performance and conversion efficiency, thereby reducing overall emissions. Some processes also reduce the coal's sulfur and mercury content directly, thus further reducing these emissions when combusting the upgraded coal. The improved combustion performance of the upgraded coal also results in lower NOx per MWh generated. The increased system efficiency realized when combusting upgraded coal leads to lower CO_2 emissions per kWh generated. However, any CO_2 generated during the treatment of the coal (i.e. firing natural gas or other fossil fuels in a thermal dryer) must be considered when evaluating coal upgrading as a means of reducing CO_2 emissions.

Boilers designed for high-moisture lignite have traditionally employed higher feed rates to account for the large latent heat load needed to evaporate fuel moisture. Separate innovative concepts developed by SynCoal Solutions and the team of Great River Energy (GRE) and Lehigh University use low-grade heat recovered from within the plant to dry incoming fuel going to the boiler, thereby boosting plant efficiency and output. In contrast, traditional thermal drying processes are complex and require high-grade heat to remove moisture from the coal.

Specifically, the GRE approach uses steam condenser and boiler exhaust heat exchangers to heat air and water fed to a fluidized-bed coal dryer upstream of the plant's coal pulverizers. Based on successful tests with a pilot-scale dryer and more than a year of continuous operation with a prototype dryer at its Coal Creek station, GRE (with DOE support and EPRI technical consultation) is now building a full suite of dryers for Unit 2 (i.e., a commercial-scale demonstration). In addition to the efficiency and CO_2 emission reduction benefits from reducing the lignite feed moisture content by about 25%, the plant's air emissions will be reduced as well. Application of this technology is not limited to PC units firing lignite. EPRI believes it may find application in PC units firing subbituminous coal and in IGCC units with dry-fed gasifiers using low-rank coals.

Direct heat application is utilized by Confluence Coal Combustion, River Basin Energy, White Energy Coal North America and Vertus Technologies to remove moisture from low-rank coals. Pilot-scale results indicate products may have lower moisture, less dust and be more resistant to self-heating than the parent coals. The transportation and combustion efficiency gains result in reduced SO_2, NOx, Hg, and CO_2 emissions even when taking into consideration emissions generated through the coal beneficiation process. White Energy has completed a facility in Indonesia and announced plans in partnership with Peabody Energy to construct coal upgrading facilities in Wyoming.

7.2.3 Coal Treatment

Coal treatment technologies use additives to enhance the coal's combustion characteristics. The technologies generally use additives such as latex, metallic or mineral reagents, or sorbents to alter the combustion process as the coal is combusted. These technologies can capture sulfur and mercury in solid byproducts from the generating process rather than allowing these coal constituents to be emitted in power plant exhaust gases. In addition, combustion performance and efficiency improvements result in lower NOx and CO_2 emissions per MWh generated.

Coal beneficiation technologies represent a significant opportunity to use coal in an efficient and environmentally sound manner. A number of companies that are operating or developing advanced, proven pre-combustion clean coal technologies formed the Coal 2.0 Alliance under the auspices of the American Coal Council. These companies include:

All Mineral – www.allmineral.com

CoalTek – www.coaltek.comConfluence Coal Combustion – www.confluencecoal.com

Evergreen Energy – www.evgenergy.com

Great River Energy – www.grenergy.com

Headwaters Energy Services – www.headwaters.com

Industrial Microwave – www.industrialmicrowave.com

River Basin Energy, Inc. – www.riverbasinenergy.com

SynCoal Solutions, Inc. – www.syncoalsolutions.com

Taggart Global, LLC – www.taggartglobal.com

Vertus Technologies, Ltd. – www.vertustechnologies.com

White Energy Coal North America, Inc. – www.whiteenergyco.com

8 Underground Coal Gasification

Findings

- UCG has the potential to yield access to the energy of hundreds of billions of tons of unmineable coal in many countries, but especially in China, India, Russia, Australia, the U.S. and Western Europe.
- UCG offers the potential to gasify coal economically and to produce a wide range of feedstocks and raw materials for economic expansion.
- UCG appears to be especially amenable to CCS because the CO_2 can be stored in the cavities formed by UCG. UCG can produce fewer emissions than conventional combustion and there is evidence that these emissions are more easily controlled.
- A confluence of energy, economic and environmental benefits make UCG an important pathway in providing energy while meeting climate change policy goals. The state of knowledge in UCG is not nascent, but rather has been developed through a variety of projects in different geological settings since the 1930s. Nevertheless, more extensive and systematic research is needed to fully assess the potential of UCG.

Recommendations

- The Council recommends that a four-year UCG program similar to that proposed by the Clean Air Task Force (2009), be implemented as soon as possible – including the development of up to five commercial scale projects within the U.S.

8.1 Introduction

The increasing global demand for energy, especially electricity, is unprecedented and will continue for decades. Coal-based power generation with CCS will be the primary source to meet this demand in terms of cleanliness, scale, availability, timeliness, security and affordability. While conventional mining of coal will continue and expand throughout the world, the opportunity to greatly increase access to vast tracts of coal deep underground holds promise for a world seeking ever more energy.

Global coal reserves are enormous and exceed eight trillion tons. At the present time, less than 1 trillion are deemed economically accessible. UCG has the potential to expand usable coal significantly, opening up opportunities to capitalize on our greatest energy asset – coal. Further, the UCG process can be utilized not only to produce electricity but also yield substitute natural gas, liquid fuel and chemicals, including ammonia and methanol.

Finally, in a carbon-constrained world, UCG may be a viable pathway to attain CO_2 emission reduction goals in the context of substantial new sources of energy:

“UCG may allow for the removal of CO_2 from the syngas before use by means of established technologies at significantly reduced cost”
Clean Air Task Force, 2009

Importantly, UCG can be linked to the CCS process itself. There is a significant coincidence between the most promising sites to utilize UCG and sites to store CO_2. The cavities formed as a result of UCG could be used for CO_2 storage (Shafirovich and Varma, 2009). In fact, Professor Paul Younger at the University of Newcastle (2008) has argued “the cavities are ideal candidates for sequestration.”

8.2 Background

The concept of UCG can be traced to research by Siemens in Germany in the 1860s. By the 1930s, the Soviets had turned these ideas into a research and development program resulting in several industrial-scale UCG facilities (Shafirovich and Varma, 2009). The Soviet program eventually gasified 15 million tons of underground coal. Discoveries of large Siberian natural gas reserves, however, led to reduced support for the program.

In the U.S., a UCG program was in place in states ranging from Wyoming to Texas to West Virginia from about 1972 to 1989 (CATF, 2009). Over 33 projects were generally supported by the DOE, with Lawrence Livermore National Laboratory as an active participant. The decline in the price of oil in the 1980s led to less support and interest in the UCG process, once again deferring insight into the long-term promise of the technology.

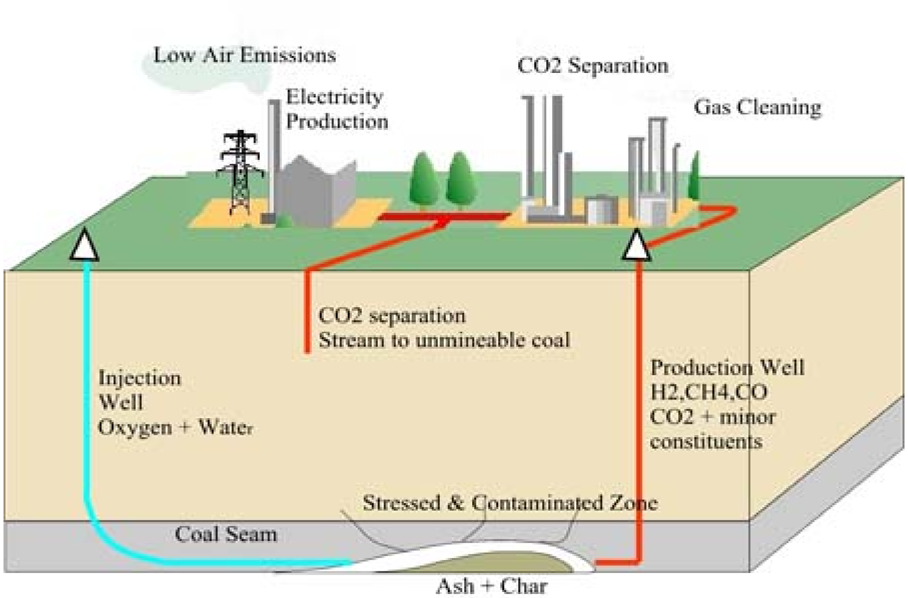
Currently, UCG research at various levels of magnitude is being carried out in China, Australia, South Africa and India (Shafirovich and Varma, 2009). Even Japan and Canada are investigating UCG possibilities. While this start/stop nature of UCG history has placed the process consistently under the radar in energy discussions, countries with coal reserves are taking a second look at the potential benefits.

In the U.S., several states with extensive coal resources are showing interest in UCG. Indiana, for example, has some of the most extensive coal reserves in the nation. But Indiana's coal accounts for only a portion of the state’s electric power and substantial amounts of coal are imported from other states. Indiana’s policy leaders have taken a renewed interest in UCG and researchers at Purdue University are some of the leading scholars in the UCG area.

8.2.1 The Process

Converting coal to gas is a well understood technology and there are upwards of 200 “surface” gasification facilities across the globe. UCG converts coal into a gaseous product commonly known as syngas through the same chemical reactions that occur in surface gasifiers. Syngas is produced and extracted through wells drilled into the coal seam. Air or oxygen may also be injected to promote the gasification reactions. The syngas is then processed at the surface for further use, or transported. The process typically relies on the natural permeability of coal seams to transmit gases to and from the gasification zone (see Figure 8-1). Enhanced permeability can be created through reverse combustion, and in-seam channel, or hydro-fracturing (Creedy and Garner, 2004). The resulting gases: H_2, CO, CH_4 and CO_2 flow to the surface through the production wells. The syngas can then be utilized in a wide variety of processes.

FIGURE 8-1
The UCG Process



Source: Underground Coal Gasification Partnership, 2009

8.3 Site Selection

The UCG process is not appropriate for every site that has coal. Further, design requirements for conventional coal mining are not necessarily pertinent to UCG. For example, some sites have hydrologic and geologic features that would deem them unsuitable for UCG processes.

Some of the most useful site selection criteria were developed at Purdue University by Shafirovich and Varma in 2009. This approach identifies seven criteria that can form the basis of site selection for a UCG project.

1. **Thickness of coal seam –** should be greater than 6 feet, as the heating value of the produced gas decreases significantly in thinner seams.
2. **Depth of coal seam –** coal seams that are shallower than 180 feet are generally not considered suitable due to the proximity to groundwater. In addition, there are two additional factors in support of deeper UCG. First, the risk of subsidence is significantly reduced at 600 feet. Second, UCG cavities below 2,500 feet can be utilized for CO_2 storage.
3. **Coal rank** – In general, the most suitable coals for UCG are low-rank, high-volatility, non-caking bituminous coals. These coals typically shrink when heated, improving permeability.

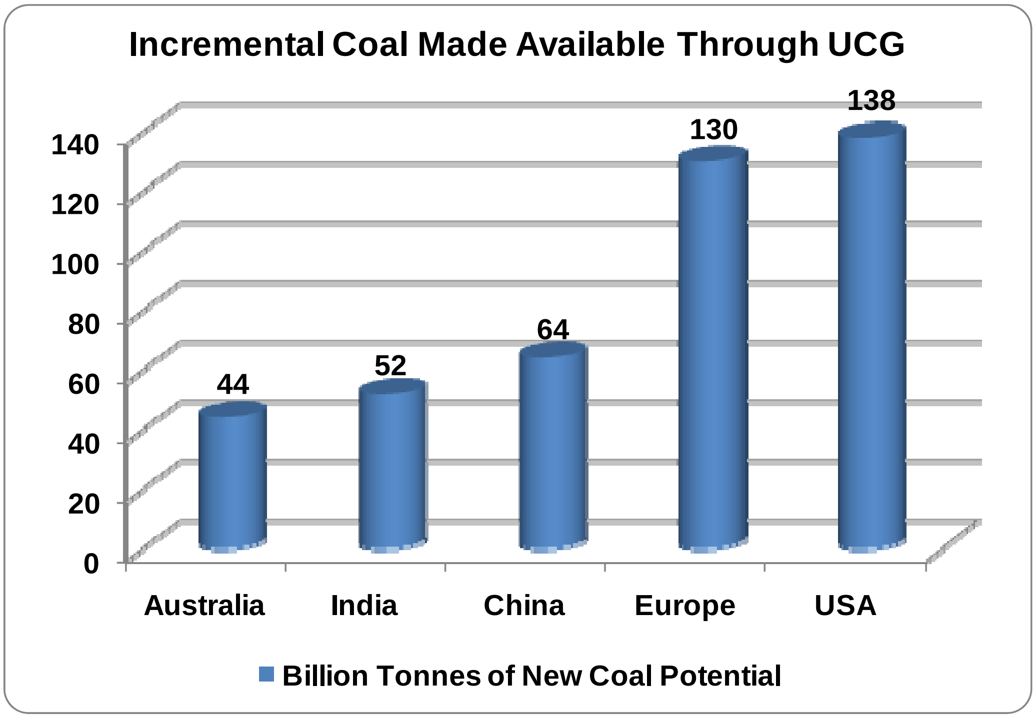
4. **Dip of seam –** There is some evidence that shallow dips are most suitable due to better drainage, with dip angles between 0 and 20 degrees seen as optimal by some researchers.
5. **Groundwater characteristics –** given the importance of water in the process, the adjoining rocks must contain an adequate deliverable volume of saline water.
6. **Amount of coal –** is a core consideration because the production lifetimes of the project may extend 20-40 years.
7. **Land use restrictions –** are important considerations in much the same way as they are for conventional mining. Since the UCG facility has less of a surface footprint than most mining operations, land use issues may be somewhat less of a problem.

8.4 Energy Benefits

If proven feasible at scale, the UCG process has the potential to open up a new vista of energy availability across the world.

Expanding the resource – given the size of global coal reserves compared to reserves considered economically mineable, it is not surprising that UCG could yield access to substantial amounts of incremental coal reserves. Friedman et al. (2007) have indicated that development of UCG in the U.S. could lead to a 300% or more increase in recoverable coal reserves. The UCG Partnership (2009) has estimated about a 50% increase in recoverable coal reserves across the globe. Regardless, however, virtually all analysts agree that UCG could potentially greatly expand access to recoverable reserves (Figure 8-2). In several major countries, UCG would gain special import because it could open the door to lower quality coal that would otherwise not be usable in typical coal-based technologies. In both China and India, for example, the predominance of high sulfur and high ash coal make UCG a particularly attractive potential technology.

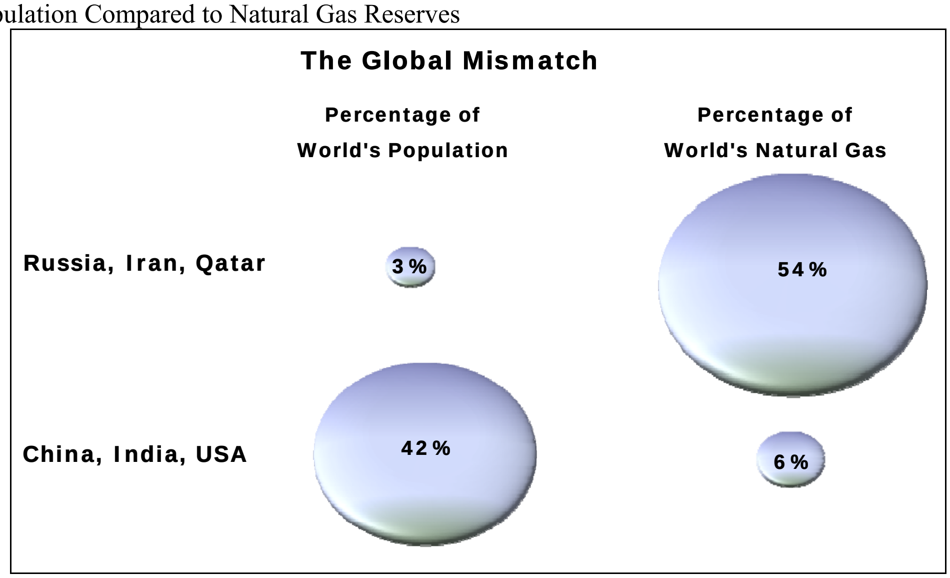
FIGURE 8-2
Incremental Coal Reserves Through UCG



8.5 Opening New Opportunities

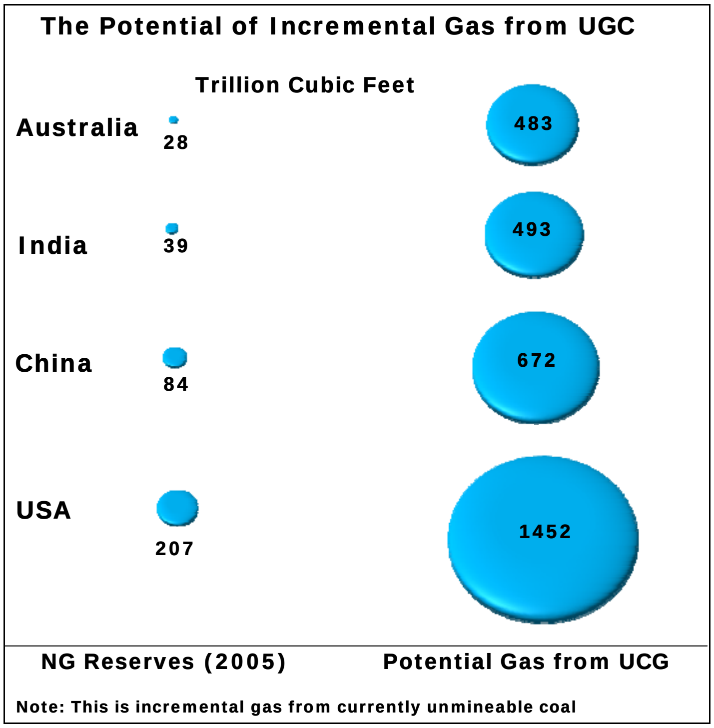
a. Conversion to natural gas – In general, and similar to the case with oil reserves, there is a mismatch between the distribution of natural gas and population (see Figure 8-3).

FIGURE 8-3
Population Compared to Natural Gas Reserves



Russia, Iran and Qatar, for example, have 54% of the world's natural gas, but only 3% of the population. At the other end of the spectrum, China, India and the U.S. have 42% of the population but only 6% of the natural gas. As Figure 8-4 shows, UCG will open up huge quantities of gas for the three most populated nations, thereby improving energy security and economic stability.

FIGURE 8-4
Potential for Incremental Gas from UCG



8.6 Economic Benefits

UCG offers many economic advantages compared to conventional surface gasification facilities:

1. Low capital investment costs because gasifiers and boilers are not required
2. Low labor costs because there is no mining underground
3. No coal storage facilities
4. Modest transportation system required as products can be piped or used in place.
5. Minimal electric transmission lines required if power plant is built on site
6. Direct use of water and feedstock in place
7. No need for waste facilities – water remains underground
8. No land reclamation
9. Economic benefits associated with fewer permits and licenses
10. Lower electricity costs – syngas from UCG operations generally has a relatively higher hydrogen concentration than syngas from surface facilities. This may give syngas from UCG a cost advantage in the production of low-carbon electricity (CATF, 2009)

8.7 Environmental Benefits

UCG also offers many environmental advantages:

1. Compared to power generation from PC or IGCC, the CO_2 reduction advantage of UCG is real and substantial. The UCG process produces less GHGs than the combination of conventional mining and coal-based power generation. For example, the UCG process only produces CO_2 and water, making the CO_2 separation much easier and less expensive.
2. Reduced emissions – as the gasification process proceeds underground, approximately half of the sulfur, mercury, tar, arsenic, ash and particulates remain there. Further, any metals or sulfur that exit with the syngas are relatively easily removed. Further, NO_x is not produced since the UCG process occurs in a reducing (no- or low-oxygen) environment.
3. Other environmental benefits include:
   - Minimal or no waste ash
   - Smaller surface footprint and land use profile
   - Reduced noise, visual impact, traffic, dust
   - Less water consumption – water for UCG comes largely from subsurface regions and typically from saline formations. Thus, less surface and groundwater is needed

8.8 Limitations and Concerns

Groundwater – stringent steps must be taken to protect groundwater including: 1) pressure management – especially operation below hydrostatic pressure and assuming no flow of VOC out of cavity, 2) appropriate selection criteria can be implemented, including sites over 600 feet, as well as intensive characterization of the site, and 3) monitoring of water chemistry and pressure (see Friedman et al, 2007).

Subsidence – is a clear concern. Fortunately, the coal industry has extensive experience in this area relating to long-wall mining. More research is needed, particularly in assessing the potential impacts of subsidence on groundwater (CATF, 2009).

Product variability – given the inherent nature of UCG as an unsteady state process, both the flow rate and heating value of the syngas will vary over time.

8.9 The Current Situation

1. **China** has the world's most extensive UCG program with over 30 ongoing projects. The coal mining group XinWen is operating six reactors that produce syngas for heating and cooking. Other Chinese operations are distributing several methanol plants in the 20,000 – 30,000 tons per year range.
2. **Australia's** Chinchilla project gasified 30,000 tons of brown coal from 1997 – 2003 and is regarded as a highly successful operation (CATF, 2009). Linc Energy has several UCG programs operating and proposed. In a particularly important

development, two Australian companies, Carbon Energy and Zero Emissions recently signed a joint agreement to cooperate on a project storing CO_2 produced from UCG.

3. **India** is committed to substantially improving its energy supply situation using UCG. A recent governmental report indicated India could expand recoverable coal reserves by 350 billion tons with UCG.
4. **South Africa's** largest utility, Eskom, began a pilot project in 2007 that now produces syngas for a 100 kW engine to produce power. Current plans are to build a 2,100 MW combined cycle plant fueled by syngas provided from a UCG facility.
5. **U.S.** – at least two characterization drilling projects are scheduled for 2009, both in Wyoming.

8.10 The Next Steps

Given the potential of UCG in terms of producing significant energy, the Clean Air Task Force (2009) has proposed a four-year program supported by the Federal Government designed to assess the viability of UCG along five broad areas:

1. Filling in the gaps in UCG basic science and technology – research is needed regarding such issues as the physical properties of coal during the gasification process, advanced simulation across three dimensions, monitoring and verification technology and module design.
2. Advancing carbon management – more information is needed on conventional geological storage of CO_2 in the UCG process, separation technologies, and the mapping of UCG and sequestration resources.
3. Ensuring environmental management – crucial concerns that UCG operators need to address if the public is going to accept the concept: 1) groundwater protection needs to be studied through simulation, laboratory work and analysis of current practice as well as prior projects, and 2) subsidence control is essential and research is needed to accelerate the development of techniques to manage and reduce surface subsidence from UCG projects.
4. Increasing human capital – UCG has not been on the front burner of energy discussions and certainly has not attracted significant research attention. At the present time no universities in the U.S. except for Purdue have programs in either research or teaching in regard to underground coal gasification. The simple fact of the matter is there are very few experts in the field within the U.S. This lack of scientific manpower is certain to slow the development of our understanding of UCG and its potential.
5. Establishing a targeted field program is essential to gain further knowledge regarding the extent we can utilize UCG for additional energy U.S. At least five pilot commercial UCG projects should be established. Further, a federally funded state-of-the-art UCG facility is necessary not merely to enhance our understanding of the process but also to help train the workforce that will be required going forward.

The CATF has proposed a budget of approximately $100 million over four years for this federal effort. In light of the benefits that UCG could eventually provide, this would be a very good investment.

8.11 Conclusion

A strong argument can be made that our understanding of the coal gasification process needs to be expanded because UCG has the potential to significantly increase the amount of recoverable coal across the world – particularly in China, India, Russia, Australia, South Africa, Europe and the United States. In terms of substitute natural gas from coal produced syngas, for example, the UCG process would greatly help balance the mismatch between natural gas resources and population in countries such as China and India.

The energy, economics and environmental benefits of UCG are extensive. In essence, UCG could eventually provide a means to increase access to greatly needed energy while readily incorporating CCS into the production process. There is widespread agreement that UCG is not only amenable to the CCS process but also can actually yield the cavities where CO_2 can be safely and securely sequestered.

Limitation and cautions regarding UCG are real and must be considered at every step: 1) UCG is not a panacea applicable to all coal sites, 2) water resources must be protected and 3) subsidence risks must be minimized and accounted for. Nevertheless, there is enough evidence based upon previous experience to suggest indicate that UCG could be a viable process to produce significant and affordable energy from coal and simultaneously help the nation and world attain climate change policy goals.

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9 U.S. as the Technology Leader

"China is not going to follow us because we're the United States. They've got $2 trillion invested in their plants and they still aren't feeding all their people. They're going to follow because we can offer them something." (J. Wayne Leonard, CEO, Entergy Corporation, March, 2009)

Findings

- The U.S. and China have emerged as the global leaders in clean coal technologies, but other countries have also made progress over the last decade.
- Nevertheless, technology transfer from the U.S. is vital to the effort to reduce global emissions of CO_2.
- This transfer will not occur at required levels unless intellectual property rights for CCS technologies are honored and protected throughout the world.
- The opportunities of such cooperation were recently demonstrated by the joint venture agreement between companies in the two countries relating to GreenGen, a $1 billion coal-based power plant with CCS scheduled for operation in Tianjing in 2011. Secretary Chu participated in the signing ceremony in Beijing in November, 2009. This cooperation was further solidified in a joint statement signed by both President Obama and President Hu Jintao.

Recommendations

- The Council recommends that DOE work with other parts of the Administration to strengthen and enhance the cooperation symbolized by the Joint Agreement between President Obama and President Hu Jianto.
- The Council recommends that the DOE support the position that all nations bear the greater share of the economic burden of CO_2 mitigation within their own borders.
- The Council recommends the DOE play a leading role in the Administration's effort to ensure that intellectual property rights for CCS technologies developed by American companies are fairly protected in other countries.
- The Council recommends that the DOE play a leading role within the Administration in developing an equitable international framework to enable widespread and affordable deployment of CCS to begin within 8 to 10 years.

9.1 Importance of Deployment of Clean Coal Technologies to Other Nations

Coal is the sustainable fuel of global economic progress for generations to come. For developing nations such as China and India, coal-based technologies are the key to meet their internal economic needs and then to enhance their economies. Economic advancement for developing countries is vital for humanitarian reasons to alleviate poverty, and in order to avoid geopolitical risks and security as well as conflict costs if the needs and aspirations of their peoples are not met.

International technology transfer is a significant means for effective technology deployment. The framework for this transfer and deployment requires needs assessments, information exchanges, capacity building, and a framework for transfer that includes both private and governmental mechanisms. U.S.-developed technology leads the world in CO_2 capture, although other nations, especially China, have their own developments. Thus, U.S. technology transfer is vital to global efforts to reduce CO_2 emissions.

Technology transfer consists of know-how and intellectual property rights (IPR). IPR are even more important for advanced technologies than for early stage development. Technologies involving IPR require investment, and transfer will not occur unless the transferors believe they will receive their expected economic rewards through the implementation of stable IPR laws and effective enforcement legal mechanisms.

9.1.1 Kyoto Protocol History and Related Issues

The Kyoto Protocol is based on the premise that the developed nations caused the increased CO_2 levels and would be responsible for addressing the issue, rather than the developing nations. China and India were placed in the latter category, known as China and the G-77. Originally, CO_2 emission reductions were only assigned to industrialized nations. At the time, the focus was that the developed nations' emissions were very large in comparison to developing nations, and arguably those developed nations already had the benefit of economic development without CO_2 reductions. While emissions worldwide are now far different (China's emissions of CO_2 are greater than those of the U.S.), China and the G-77 continue to press for the developed countries to bear the major economic burden of CO_2 emission reductions.

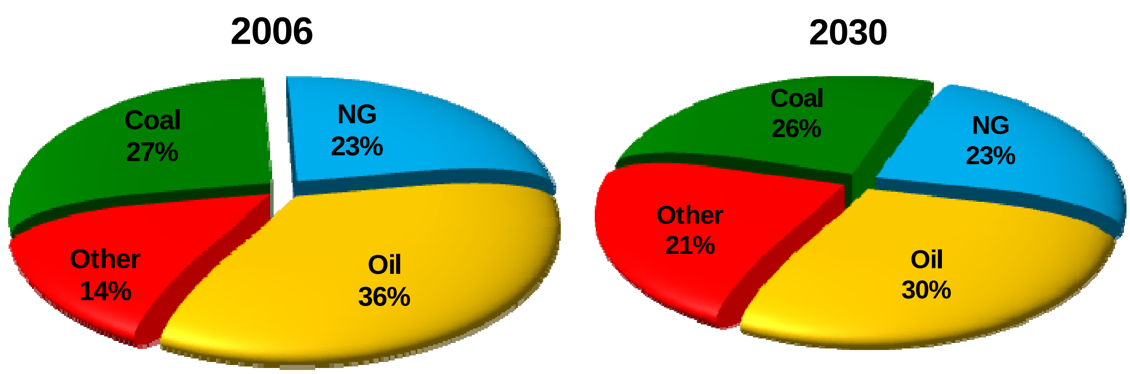
There are geopolitical and security risks as well as conflict costs if China and the G-77 countries cannot meet the rising demand for energy, including electricity, for 80% of the world's people. These nations rely primarily on fossil fuels, especially coal, and are expected to increase their energy and coal use to meet rising needs. Technology transfer is a key part of meeting this critical growth in demand.

9.1.2 The Steady Increase in Global Energy Demand

World energy consumption is projected to increase from 472 quadrillion Btu in 2006 to 678 quadrillion Btu in 2030 -- an increase of 44%. This additional demand is equal to the **combined** current consumption of the U.S., the European Union, and Japan.

This projected increase in energy demand will have at least two distinguishing characteristics: 1) the countries of developing Asia -- India, China, and other nations in the region --will account for 59% of the world's incremental energy consumption and 2), the three primary fossil fuels -- oil, natural gas and coal -- met over 85% of consumption in 2006 and will meet about 80% in 2030. Figure 9-1 demonstrates the percentage of energy fossil fuels will continue to provide at the global level.

FIGURE 9-1
Fossil Fuels will be the Continuing Core of Global Energy Supply



Source: EIA (2009)
Note: NG = natural gas

Coal-based power generation will be a major component of electricity supply in many countries, but the developing Asian nations will account for over 85% of the global increase in coal-based generation through 2030.Given their respective energy reserves, as shown in Table 9-1, it is not surprising that China and India will increasingly turn to coal as a reliable source of electricity.

TABLE 9-1
Percentages of Global Population and Energy Reserves

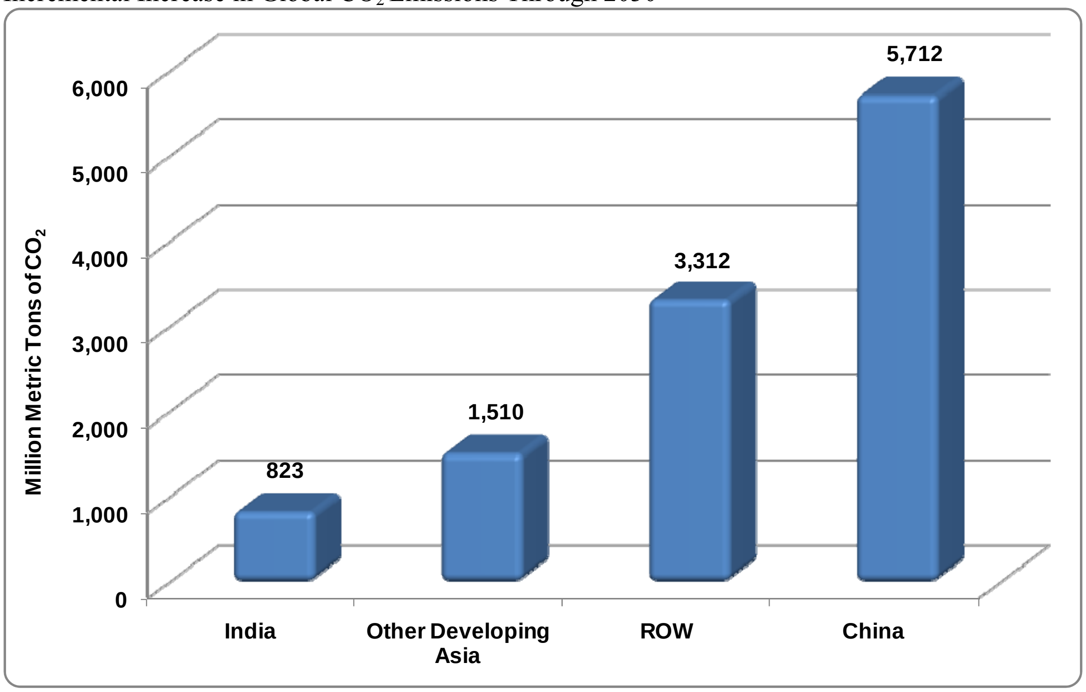
		% of Global Energy Reserves		
Nation	**% of Global Population**	**Oil**	**NG**	**Coal**
China	20	1	1	14
India	17	<1	<1	7
Total	37	2	2	21

Source: British Petroleum (2009)

9.1.3 Economic Growth and GHG Emissions

An inevitable effect of both economic growth and energy production and consumption is the generation of GHG emissions, including CO_2. Given the vast expanses of poverty, economic growth must continue throughout the world. This growth will largely be fueled by coal, natural gas, and oil. Hence, reductions in carbon intensity and in CO_2 emission levels in developed countries are very likely to be completely offset by a wave of much higher energy consumption and CO_2 emissions from China and other developing countries (see Figure 9-2). In fact, the Congressional Budget Office (2007) has projected that over the next 20 years, developing countries will account for two thirds of the global growth in CO_2 emissions.

FIGURE 9-2
Incremental Increase in Global CO_2 Emissions Through 2030



Source: EIA (2009)

Achieving absolute reductions in CO_2 emissions, while maintaining economic growth, is extremely difficult. While some nations continue to reduce carbon intensity, the rising tide of energy consumption due to population and economic growth will continue to offset the emission reductions from declining carbon intensity. Technological innovation is key to effectively reducing global CO_2 emissions. This is why current policies that support a flexible, market-based approach toward CO_2 management are most likely to achieve long-term results at the least possible cost to society. Technology transfer, for example, has great promise for reducing future increases in CO_2 emissions in developing countries, the projected source of the bulk of CO_2 emission growth.

9.1.4 The Importance of Clean Coal Technology in Developing Nations

Global reductions in CO_2 emissions cannot be successfully achieved without action by China, India, and developed nations. Given the dramatic surge of fossil fuel consumption in developing Asia and the rest of the developing world, the role of advanced coal-based technologies and their infusion into developing nations becomes paramount. Electricity is the lever by which these nations seek to improve the quality of life for their citizens. They will continue to turn to coal and other fossil fuels to generate low-cost, reliable electricity.

Technological input from the developed nations is of central importance in achieving CO_2 emission reductions amid economic growth. In fact, the IEA has stated that CO_2 emission reduction goals and economic prosperity cannot be attained without such new technologies as CCS.

China is a good example of a nation facing the daunting convergence of growing energy demand, CO_2 emission reduction goals, and the transition to new technologies. The IEA (2009) has identified several key areas where China has struggled regarding the availability of advanced coal mining technologies:

- Resource wastage -- recovery at Chinese mines averages 35% rather than the 50% plus which might be expected in advanced mines.
- Inability to mine deeper seams -- the average depth of mines in China is 1,299 feet. That depth will have to be increased by at least 25% to meet projected needs.
- Mining safety -- equipment is outdated in many state-owned mines and one third is operated beyond its design life.
- Transportation -- new railways will have to be built to provide access from such areas as Shanxi and Inner Mongolia.

In addition, the IEA has indicated China's trajectory of using more coal will require the technological infusion from developed nations in several key areas including:

- coal drying
- particulate removal
- combined SO_2 and NOx removal
- polygeneration with H_2 production
- CCS
- coal liquefaction with CCS

Further, research by Mao (2009) has indicated that increased **efficiency** in the consumption of coal is one of the most critical issues facing China (see Table 9-2):

TABLE 9-2
China's Continued Need to Improve Efficiency in Power Generation

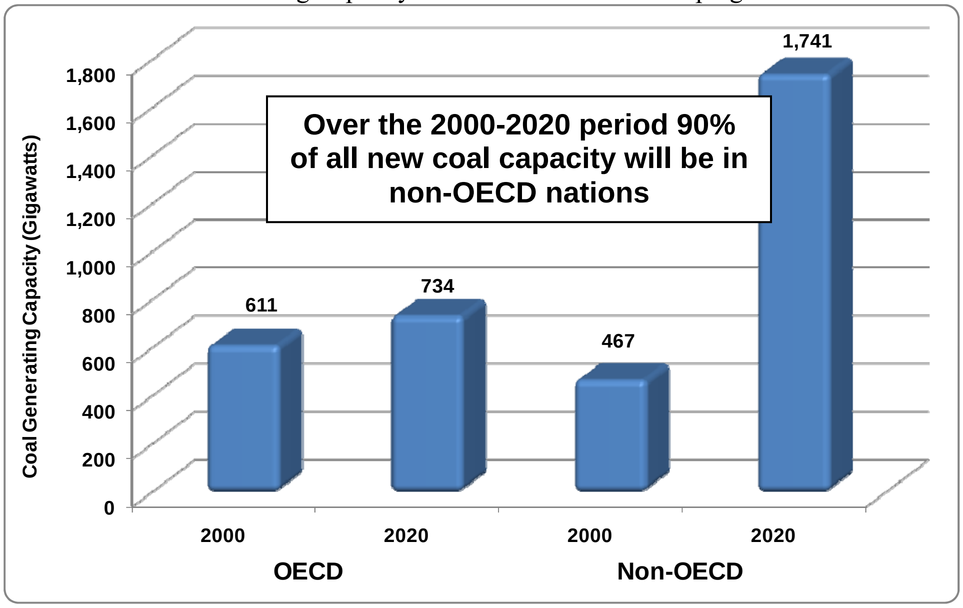
Year	2002	2003	2004	2005	2006	2007	2008	World Level
Coal Consumption (g/kWh)	383	380	376	374	366	357	349	316

Source: Mao (2009)

9.1.5 The Crucial Role of Retrofitting Existing Coal-Based Generation Facilities with CCS

Perhaps no more important step can be taken toward CO_2 emission reduction goals than the retrofitting of existing coal-based generation facilities with CCS technologies. The dramatic rise in coal-based generation capacity in the developing world over the last decade, and in the coming decade, speaks volumes as to the potential benefits of CCS retrofit.

FIGURE 9-3
New Coal-Based Generating Capacity is Concentrated in Developing Nations



Source: EIA (2009)

As Figure 9-3 shows, over the period 2000-2020 an estimated 1,400 GW of coal-based generation will be added to global generating capacity -- an increase of 130%. Further, over 90% of this new generation will be in developing nations, especially China and India. Since much of this new capacity is already built or currently under construction, it is clear that CCS technologies will have to be retrofitted onto these facilities to bring meaningful progress toward meeting CO_2 emission reduction goals. Given the lead role of the U.S., the issues associated with technological transfer gain great importance. In fact, a major symposium at MIT in March 2009 made this point clearly:

> **"The world cannot achieve significant reductions in CO_2 emissions, avoiding the most disruptive impacts of climate change, without commitments to reduce emissions from existing coal-fired power plants... The U.S. and China have a shared interest in developing and deploying a range of technologies to retrofit existing coal fired power plants. Bilateral approaches on climate change should be encouraged and supported... joint research programs... should be supported and funded. A mechanism for sharing the results of unilateral projects should be created and supported."**

9.1.6 China Has Large and Increasing CO_2 Emissions

Coal is the essential energy resource for China to meet its internal demands for electrical power in order to improve the living standards of its people. Coal is seen as a key fuel of the future. China's electrical power generation continues to grow rapidly, dominated by coal power plants. Its rapidly increasing CO_2 emissions are due to it growing number of coal-fired power plants without CCS. China now emits more GHGs than the U.S. and has been the largest CO_2 emitting nation since 2007 (EIA, 2009). Its power sector is challenged by low efficiency and high emissions. Global reductions in CO_2 emissions cannot be achieved without action by China.

While China is moving to develop and demonstrate CCS, including through international cooperative projects, China's emphasis is on efficiency gains and development of renewable energy sources. However, efficiency improvements and renewable energy alone will not be sufficient for effective mitigation of CO_2 emissions. Rather, the emphasis needs to be on clean coal technologies with the lowest levels of CO_2 produced to reduce the nation's GHG footprint.

There are ongoing talks between China and the U.S. and progress has occurred. China and the U.S. are engaged in developing a collaborative economic and strategic relationship regarding climate change. In July 2009, the two nations signed a memorandum of understanding to share CCS technologies. In November 2009, President Obama and President Hu Jintao signed a "Joint Statement" indicating:

> **"The two sides strongly welcomed work in both countries to promote 21st century coal technologies. They agreed to promote cooperation on large-scale carbon capture and sequestration (CCS) demonstration projects and to begin work immediately on the development, deployment, diffusion, and transfer of CCS technology. The two sides welcomed recent agreements between Chinese and U.S. companies, universities, and research institutions to cooperate on CCS and more efficient coal technologies."**

One of the most apparent joint projects is **GreenGen,** where U.S. and Chinese companies recently signed agreements to build a $1 billion coal-based facility with CCS in Tianjin.

China also has significant CCS technologies and project execution ability. It also is engaged in technology development through international governmental and combined government-private new technology initiatives, including the Green Gen Program which is a major R&D and demonstration project pursuing gasification technology. Major pieces of the equipment were designed and made in China. In addition, China's ECUST and TPRI gasification technologies have been licensed abroad. China, however, is not likely to act alone in the new technology development process. One priority for China is technology access and IPR because it has only limited CO_2 capture and beneficial use technologies in the face of large, rising CO_2 emissions.

9.1.7 India's Growth with Corresponding Large Increase in CO_2 Emissions but Without a Plan for CCS

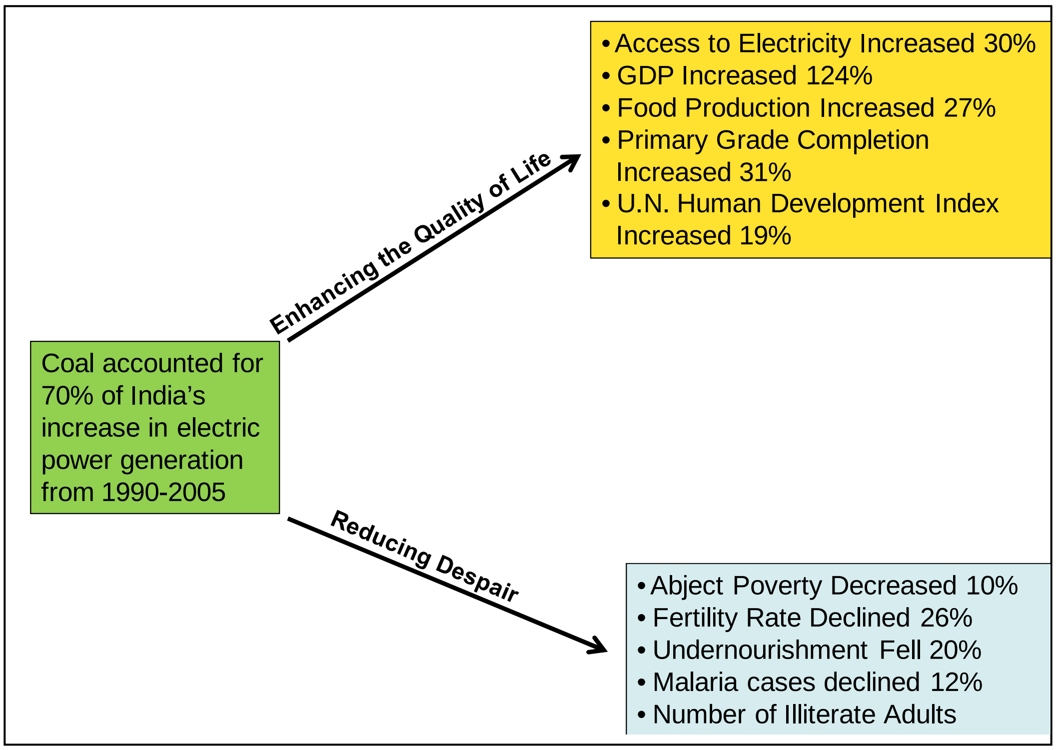
In 2008, The World Bank stated:

- "India needs much more power in a short time frame to continue its economic development."
- "India still must rely on (coal) to meet growing demand."

- “Gas-based power is not a viable alternative …not enough natural gas is available …and the power it generates is too expensive.”
- “Wind power still has limited reliability and its higher cost …makes it unsustainable for meeting large scale demand.”

Use of coal has had major positive impacts in India, as shown in Figure 9-4. Increasing electricity is a national priority. Thus, coal is the key fuel of the future for India as well.

FIGURE 9-4
Coal’s Track Record in India



India is a major GHG emitter. In 2008, India was the 4th largest CO_2 emitter, with increasing CO_2 emissions, 43% of which are from electricity generation and petroleum refining. While India points to its per capita emissions as being very low, its total CO_2 emissions are among the world’s highest. However, India is not moving forward meaningfully with reductions in CO_2 emissions due to its priority of national development and view that it has a lower per capita emission rate than the developed nations. Yet, clean coal technology needs to be implemented in India if global reductions in CO_2 emissions are to be achieved.

India continues to join with China to oppose binding CO_2 emission reductions. In August 2009, Prime Minister Singh stated that the developed nations should not expect the developing countries to pay for reducing global CO_2 levels caused by wealthy nations. In September 2009, an article in *The Washington Post* suggested India may be somewhat softening its stance:

“India had thus far rejected emission cuts, declaring that they would compromise the populous nation's economic growth, even as developed countries criticized its intransigence. But under a proposed national law, India may set limits on greenhouse gas emissions over the coming decade, focusing on energy efficiency, new building codes, clean energy, and fuel economy standards.”

9.1.8 Global Reductions in CO_2 Emissions Cannot be Achieved Without Technology Transfer

China’s coal-based power plants are one of the main causes of its increasing CO_2 emissions. China’s electrical power generation will continue to grow rapidly, dominated by new coal-based power plants. While China is willing to participate in international public and public-private new technology efforts, it does not tend to be a pioneer itself in developing new clean energy technologies. Moreover, it remains opposed to bearing the costs of CCS, and therefore will not engage in the necessary actions to reduce its CO_2 emissions unless a shift in its policy takes place.

9.1.9 Importance of Intellectual Property Protection as Part of CCS Technology Transfer

The U.S. is not the only nation developing CCS technologies. However, the strong array of technology development in the U.S. means that U.S. technology transfer is essential for effective CO_2 emission reductions in China. At the same time, effective American technology transfer is significantly impeded without meaningful protection of American companies’ IPR.

9.1.10 Current Lack of Meaningful Patent Protection in China

Patent protection is relatively weak in China. IPR infringement is viewed as a threat by foreign technology companies. While Chinese IPR protection looks good in theory, rights are often not enforced. Part of the problem is due to the use of a Western-style IPR approach which lacks the support and often faces hostility in Chinese provincial governments responsible for most IPR enforcement. This is compounded by discrimination at times against foreign companies, local protectionism, and uncertainties about the laws and their application, given the nation’s relatively short patent law history and fragmented judicial system.

While enforcement of IPR is improving, it is still inadequate. Therefore, IPR often are not meaningful. The Supreme People’s Court (SPC) has re-organized the judicial system for handling disputes concerning the granting of patent and trademark rights. As of July 1, 2009, the Beijing IPR tribunals of the two Intermediate and High People’s Courts as well as the SPC will have exclusive jurisdiction over first- and second-instance administrative cases, arising from issuance of registrations for patents, trademarks, layout designs of integrated circuits, and new plant varieties. The SPC views this re-structuring as an important step towards streamlining the Chinese IPR trial system.

9.1.11 Lack of Patent Protection is an Important Barrier to Effective Technology Deployment and Must be Addressed

At a time when technology deployment is critical for global efforts to reduce CO_2 emissions, the Congress has expressed its concerns about the loss of technology rights for American companies due to the lack of IPR protection. This past summer, the House of Representatives unanimously voted that U.S. policy is to prevent U.S. intellectual property rights from being weakened by the Copenhagen Climate Change Treaty. Congress indicated that such weakening would further increase our trade deficit and lead to the loss of potential jobs in the U.S.

Any approach to ensuring appropriate IPR protection in China must take into account China's legitimate interest in developing its own economy, including equipment manufacturing and other technology-based industry, for both its internal markets and export to world markets. Since many other nations have similar interests and provide reasonable IPR, the legitimate interests of China should be compatible with IPR protection allowing effective technology transfer. Moreover, if Chinese exports were to be in violation of IPR held by companies in other nations, there could be serious and extensive IPR litigation in a variety of forums which would not be in the best interests of mitigating CO_2 emissions, any nation, or any technology provider.

9.2 Summary

The U.S. needs to continue vigorous cooperative efforts with China and other nations to create a worldwide approach to address CO_2 emissions. Unilateral action, or even action by the developed nations alone, will be inadequate to meet these challenges. It is economically unrealistic to expect only the U.S. and other developed nations to bear the great economic burden of global CO_2 emission reduction goals. Since technology transfer is a vital part of these efforts, and American companies need to be able to participate on a fair basis to address global CO_2 reduction goals, and also for the economic well-being of our nation, the U.S. must act to ensure that U.S. companies' IPR for CCS technologies are adequately protected around the world.

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