The Future of Coal

OPTIONS FOR A CARBON-CONSTRAINED WORLD
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Members did not approve or endorse the report and individual members of the advisory committee have different views on one or more of matters addressed in this report
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In 2002, a group of MIT Faculty decided to undertake a series of interdisciplinary studies about how the United States and the world would meet future energy demand without increasing emissions of carbon dioxide (CO\textsubscript{2}) or other greenhouse gases. The first study “The Future of Nuclear Power” appeared in 2003. In 2004 a similar group of MIT faculty undertook the present study, “The Future of Coal.” The purpose of the study is to examine the role of coal in a world where constraints on carbon emissions are adopted to mitigate global warming. The study’s particular emphasis is to compare the performance and cost of different coal combustion technologies when combined with an integrated system for CO\textsubscript{2} capture and sequestration.

Our audience is government, industry and academic leaders and decision makers interested in the management of the interrelated set of technical, economic, environmental, and political issues that must be addressed in seeking to limit and to reduce greenhouse gas emissions to mitigate the effects of climate change. Coal is likely to remain an important source of energy in any conceivable future energy scenario. Accordingly, our study focuses on identifying the priority actions needed to reduce the CO\textsubscript{2} emissions that coal use produces. We trust that our integrated analysis will stimulate constructive dialogue both in the United States and throughout the world.

This study reflects our conviction that the MIT community is well equipped to carry out interdisciplinary studies of this nature to shed light on complex socio-technical issues that will have major impact on our economy and society.
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Executive Summary

This MIT study examines the role of coal as an energy source in a world where constraints on carbon emissions are adopted to mitigate global warming. Our first premise is that the risks of global warming are real and that the United States and other governments should and will take action to restrict the emission of CO₂ and other greenhouse gases. Our second and equally important premise is that coal will continue to play a large and indispensable role in a greenhouse gas constrained world. Indeed, the challenge for governments and industry is to find a path that mitigates carbon emissions yet continues to utilize coal to meet urgent energy needs, especially in developing economies. The scale of the enterprise is vast. (See Box 1).

Our purpose is to identify the measures that should be taken to assure the availability of demonstrated technologies that would facilitate the achievement of carbon emission reduction goals, while continuing to rely on coal to meet a significant fraction of the world's energy needs. Our study has not analyzed alternative carbon emission control policies and accordingly the study does not make recommendations on what carbon mitigation measure should be adopted today. Nevertheless, our hope is that the study will contribute to prompt adoption of a comprehensive U.S. policy on carbon emissions.

We believe that coal use will increase under any foreseeable scenario because it is cheap and abundant. Coal can provide usable energy at a cost of between $1 and $2 per MMBtu compared to $6 to $12 per MMBtu for oil and natural gas. Moreover, coal resources are distributed in regions of the world other than the Persian Gulf, the unstable region that contains the larg-

BOX 1  ILLUSTRATING THE CHALLENGE OF SCALE FOR CARBON CAPTURE

- Today fossil sources account for 80% of energy demand: Coal (25%), natural gas (21%), petroleum (34%), nuclear (6.5%), hydro (2.2%), and biomass and waste (11%). Only 0.4% of global energy demand is met by geothermal, solar and wind.¹
- 50% of the electricity generated in the U.S. is from coal.²
- There are the equivalent of more than five hundred, 500 megawatt, coal-fired power plants in the United States with an average age of 35 years.²
- China is currently constructing the equivalent of two, 500 megawatt, coal-fired power plants per week and a capacity comparable to the entire UK power grid each year.³
- One 500 megawatt coal-fired power plant produces approximately 3 million tons/year of carbon dioxide (CO₂).³
- The United States produces about 1.5 billion tons per year of CO₂ from coal-burning power plants.
- If all of this CO₂ is transported for sequestration, the quantity is equivalent to three times the weight and, under typical operating conditions, one-third of the annual volume of natural gas transported by the U.S. gas pipeline system.³
- If 60% of the CO₂ produced from U.S. coal-based power generation were to be captured and compressed to a liquid for geologic sequestration, its volume would about equal the total U.S. oil consumption of 20 million barrels per day.
- At present the largest sequestration project is injecting one million tons/year of carbon dioxide (CO₂) from the Sleipner gas field into a saline aquifer under the North Sea.³

Notes
1. IEA Key World Energy Statistics (2006)
2. EIA 2005 annual statistics (www.eia.doe.gov)
3. Derived from the MIT Coal Study
est reserves of oil and gas. In particular the United States, China and India have immense coal reserves. For them, as well as for importers of coal in Europe and East Asia, economics and security of supply are significant incentives for the continuing use of coal. Carbon-free technologies, chiefly nuclear and renewable energy for electricity, will also play an important role in a carbon-constrained world, but absent a technological breakthrough that we do not foresee, coal, in significant quantities, will remain indispensable.

However, coal also can have significant adverse environmental impacts in its production and use. Over the past two decades major progress has been made in reducing the emissions of so-called “criteria” air pollutants: sulfur oxides, nitrogen oxides, and particulates from coal combustion plants, and regulations have recently been put into place to reduce mercury emissions. Our focus in this study is on approaches for controlling CO₂ emissions. These emissions are relatively large per Btu of heat energy produced by coal because of its high carbon content.

We conclude that CO₂ capture and sequestration (CCS) is the critical enabling technology that would reduce CO₂ emissions significantly while also allowing coal to meet the world’s pressing energy needs.

To explore this prospect, our study employs the Emissions Predictions and Policy Analysis (EPPA) model, developed at MIT, to prepare scenarios of global coal use and CO₂ emissions under various assumptions about the level and timing of the carbon charge¹ that might be imposed on CO₂ emissions and the cost of removing CO₂ from coal. The response of the global economy to placing a price on CO₂ emissions is manifold: less energy is used, there is switching to lower carbon fuels, the efficiency of new and existing power plants is improved, and new carbon control technologies are introduced, for example CCS. In characterizing the CO₂ emission price, we employ a “high” price trajectory that starts at $25/tonne-CO₂ in 2015 and increases thereafter at a real rate of 4% per year. The $25 per tonne price is significant because it approaches the level that makes CCS technology economic.

We also examine a “low” price trajectory that begins with a CO₂ emission price of $7/tonne in 2010 and increases at a rate of 5% thereafter. The key characteristic of the “low” price is that it reaches the initial “high” price level nearly 25 years later. Other assumptions studied include the development of nuclear power to 2050 (limited or expanded) and the profile of natural gas prices (as calculated by the model or at a lower level).

Our conclusion is that coal will continue to be used to meet the world’s energy needs in significant quantities. The high CO₂-price scenario leads to a substantial reduction in coal use in 2050 relative to “business as usual” (BAU), but still with increased coal use relative to 2000 in most cases. In such a carbon-constrained world, CCS is the critical future technology option for reducing CO₂ emissions while keeping coal use above today’s level. Table 1 shows the case with higher CO₂ prices and applying the EPPA model’s reference projection for natural gas prices. The availability of CCS makes a significant difference in the utilization of coal at mid-century regardless of the level of the CO₂ prices (not shown in the table) or the assumption about nuclear power growth. With CCS more coal is used in 2050 than today, while global CO₂ emissions from all sources of energy are only slightly higher than today’s level and less than half of the BAU level. A major contributor to the global emissions reduction for 2050 is the reduction in CO₂ emissions from coal to half or less of today’s level and to one-sixth or less that in the BAU projection.

¹. This carbon charge may take the form of a direct tax, a price imposed by a cap-and-trade mechanism, or some other type of regulatory constraint on CO₂ emissions. We shall refer to this charge as a tax, price, penalty, or constraint interchangeably throughout this report and the use of one form or another should not be taken as an indication of a preference for that form unless so stated.
The “low” CO₂ price scenario reaches the level where CCS becomes economic some 25 years later than under the higher price case. As a result coal consumption is higher in 2050 relative to the high CO₂ price scenario and, in addition, the contribution of CCS is much lower, thus leading to substantially higher CO₂ emissions.

Today, and independent of whatever carbon constraints may be chosen, the priority objective with respect to coal should be the successful large-scale demonstration of the technical, economic, and environmental performance of the technologies that make up all of the major components of a large-scale integrated CCS system — capture, transportation and storage. Such demonstrations are a prerequisite for broad deployment at gigatonne scale in response to the adoption of a future carbon mitigation policy, as well as for easing the trade-off between restraining emissions from fossil resource use and meeting the world’s future energy needs.

Successful implementation of CCS will inevitably add cost for coal combustion and conversion. We estimate that for new plant construction, a CO₂ emission price of approximately $30/tonne (about $110/tonne C) would make CCS cost competitive with coal combustion and conversion systems without CCS. This would be sufficient to offset the cost of CO₂ capture and pressurization (about $25/tonne) and CO₂ transportation and storage (about $5/tonne). This estimate of CCS cost is uncertain; it might be larger and with new technology, perhaps smaller.

The pace of deployment of coal-fired power plants with CCS depends both on the timing and level of CO₂ emission prices and on the technical readiness and successful commercial demonstration of CCS technologies. The timing and the level of CO₂ emission prices is uncertain. However, there should be no delay in undertaking a program that would establish the option to utilize CCS at large scale in response to a carbon emission control policy that would make CCS technology economic. Sequestration rates of one to two gigatonnes of carbon (nearly four to eight gigatonnes of CO₂) per year by mid-century will enable appreciably enhanced coal use and significantly reduced CO₂ emissions.

What is needed is to demonstrate an integrated system of capture, transportation, and storage of CO₂ at scale. This is a practical goal but requires concerted action to carry out. The integrated demonstration must include a properly instrumented storage site that operates under a regulatory framework which includes site selection, injection and surveillance,
and conditions for eventual transfer of liability to the government after a period of good practice is demonstrated.

An explicit and rigorous regulatory process that has public and political support is prerequisite for implementation of carbon sequestration on a large scale. This regulatory process must resolve issues associated with the definition of property rights, liability, site licensing and monitoring, ownership, compensation arrangements and other institutional and legal considerations. Regulatory protocols need to be defined for sequestration projects including site selection, injection operation, and eventual transfer of custody to public authorities after a period of successful operation. In addition to constraints of CO₂ emissions, the pacing issues for the adoption of CCS technology in a greenhouse gas constrained world are resolution of the scientific, engineering, and regulatory issues involved in large-scale sequestration in relevant geologies. These issues should be addressed with far more urgency than is evidenced today.

At present government and private sector programs to implement on a timely basis the required large-scale integrated demonstrations to confirm the suitability of carbon sequestration are completely inadequate. If this deficiency is not remedied, the United States and other governments may find that they are prevented from implementing certain carbon control policies because the necessary work to regulate responsibly carbon sequestration has not been done. Thus, we believe high priority should be given to a program that will demonstrate CO₂ sequestration at a scale of 1 million tonnes CO₂ per year in several geologies.

We have confidence that large-scale CO₂ injection projects can be operated safely, however no CO₂ storage project that is currently operating (Sleipner, Norway; Weyburn, Canada; In Salah, Algeria) has the necessary modeling, monitoring, and verification (MMV) capability to resolve outstanding technical issues, at scale. Each reservoir for large-scale sequestration will have unique characteristics that demand site-specific study, and a range of geologies should be investigated. We estimate that the number of at-scale CCS projects needed is about 3 in the U.S. and about 10 worldwide to cover the range of likely accessible geologies for large scale storage. Data from each project should be thoroughly analyzed and shared. The cost per project (not including acquisition of CO₂) is about $15 million/year for a ten-year period.

CO₂ injection projects for enhanced oil recovery (EOR) have limited significance for long-term, large-scale CO₂ sequestration — regulations differ, the capacity of EOR projects is inadequate for large-scale deployment, the geological formation has been disrupted by production, and EOR projects are usually not well instrumented. The scale of CCS required to make a major difference in global greenhouse gas concentrations is massive. For example, sequestering one gigatonne of carbon per year (nearly four gigatonnes of carbon dioxide) requires injection of about fifty million barrels per day of supercritical CO₂ from about 600 1000MWₑ of coal plants.

While a rigorous CO₂ sequestration demonstration program is a vital underpinning to extended CCS deployment that we consider a necessary part of a comprehensive carbon emission control policy, we emphasize there is no reason to delay prompt adoption of U.S. carbon emission control policy until the sequestration demonstration program is completed.
A second high-priority requirement is to demonstrate CO\textsubscript{2} capture for several alternative coal combustion and conversion technologies. At present Integrated Gasification Combined Cycle (IGCC) is the leading candidate for electricity production with CO\textsubscript{2} capture because it is estimated to have lower cost than pulverized coal with capture; however, neither IGCC nor other coal technologies have been demonstrated with CCS. It is critical that the government RD&D program not fall into the trap of picking a technology “winner,” especially at a time when there is great coal combustion and conversion development underway in the private sector in both the United States and abroad.

Approaches with capture other than IGCC could prove as attractive with further technology development for example, oxygen fired pulverized coal combustion, especially with lower quality coals. Of course, there will be improvements in IGCC as well. R&D is needed on sub-systems, for example on improved CO\textsubscript{2} separation techniques for both oxygen and air driven product gases and for oxygen separation from air. The technology program would benefit from an extensive modeling and simulation effort in order to compare alternative technologies and integrated systems as well as to guide development. Novel separation schemes such as chemical looping should continue to be pursued at the process development unit (PDU) scale. The reality is that the diversity of coal type, e.g. heat, sulfur, water, and ash content, imply different operating conditions for any application and multiple technologies will likely be deployed.

Government support will be needed for these demonstration projects as well as for the supporting R&D program. Government assistance is needed and should be provided to demonstrate the technical performance and cost of coal technologies with CCS, including notably IGCC. There is no operational experience with carbon capture from coal plants and certainly not with an integrated sequestration operation. Given the technical uncertainty and the current absence of a carbon charge, there is no economic incentive for private firms to undertake such projects. Energy companies have advanced a number of major projects and all have made clear the need for government assistance in order to proceed with unproved “carbon-free” technology.

The U.S 2005 Energy Act contains provisions that authorize federal government assistance for IGCC or pulverized coal plants containing advanced technology projects with or without CCS. We believe that this assistance should be directed only to plants with CCS, both new plants and retrofit applications on existing plants. Many electric utilities and power plant developers who are proposing new coal-fired electricity generating units are choosing super-critical pulverized coal units because in the absence of charges on CO\textsubscript{2} emissions, the bus bar cost of generating electricity (COE) from pulverized coal (PC) power plants is lower than IGCC and its availability is higher. These prospective new plants, as well as the existing stock of coal-fired power plants, raise the issue of the future retrofit of coal-fired power plants that are in existence at the time when a carbon charge is imposed. This problem is distinct from that of the technology to be chosen for the new power plants that will be built after a carbon charge has been imposed. Pending adoption of policies to limit CO\textsubscript{2} emissions, if federal assistance is extended to coal projects, it should be limited to projects that employ CCS.

It has been argued that the prospect of a future carbon charge should create a preference for the technology that has the lowest cost of retrofit for CO\textsubscript{2} capture and storage, or that power plants built now should be “capture-ready,” which is often interpreted to mean that new coal-fired power plants should be IGCC only.
From the standpoint of a power plant developer, the choice of a coal-fired technology for a new power plant today involves a delicate balancing of considerations. On the one hand, factors such as the potential tightening of air quality standards for SO$_2$, NO$_x$, and mercury, a future carbon charge, or the possible introduction of federal or state financial assistance for IGCC would seem to favor the choice of IGCC. On the other hand, factors such as near-term opportunity for higher efficiency, capability to use lower cost coals, the ability to cycle the power plant more readily in response to grid conditions, and confidence in reaching capacity factor/efficiency performance goals would seem to favor the choice of super critical pulverized coal (SCPC). Other than recommending that new coal units should be built with the highest efficiency that is economically justifiable, we do not believe that a clear preference for either technology can be justified.

Moreover, retrofitting an existing coal-fired plant originally designed to operate without carbon capture will require major technical modification, regardless of whether the technology is SCPC or IGCC. The retrofit will go well beyond the addition of an “in-line” process unit to capture the CO$_2$; all process conditions will be changed which, in turn, implies the need for changes to turbines, heat rate, gas clean-up systems, and other process units for efficient operation. Based on today’s engineering estimates, the cost of retrofitting an IGCC plant, originally designed to operate without CCS so as to capture a significant fraction of emitted carbon, appears to be cheaper than the retrofit cost of a SCPC plant. However, this characteristic of IGCC has not been demonstrated.” Also, even if the retrofit cost of an IGCC plant is cheaper, the difference in the net present value of an IGCC and SCPC plant built now and retrofitted later in response to a future carbon charge depends heavily on the estimate of the timing and size of a carbon charge, as well as the difference in retrofit cost. Essentially, there is a trade-off between cheaper electricity prior to the carbon charge and higher cost later.

Opportunity to build “capture ready” features into new coal plants, regardless of technology, are limited. Other than simple modification to plant layout to leave space for retrofit equipment such as shift reactors, pre-investment in “capture ready” features for IGCC or pulverized coal combustion plants designed to operate initially without CCS is unlikely to be economically attractive. It would be cheaper to build a lower capital cost plant without capture and later either to pay the price placed on carbon emissions or make the incremental investment in retrofitting for carbon capture when justified by a carbon price. However, there is little engineering analysis or data to explore the range of pre-investment options that might be considered.

There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be “grandfathered” by the grant of free CO$_2$ allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this “grandfathering” loophole before it becomes a problem.

The DOE Clean Coal program is not on a path to address our priority recommendations because the level of funding falls far short of what is required and the program content is not aligned with our strategic objectives. The flagship DOE project, FutureGen, is consistent with our priority recommendation to initiate integrated demonstration projects at scale. However, we have some concerns about this particular project, specifically the need
to clarify better the project objectives (research vs. demonstration), the inclusion of international partners that may further muddle the objectives, and whether political realities will allow the FutureGen consortium the freedom to operate this project in a manner that will inform private sector investment decisions.

Responsibility for the integrated CCS demonstration projects, including acquisition of the CO₂ needed for the sequestration demonstration, should be assigned to a new quasi-government Carbon Sequestration Demonstration Corporation. The corporation should select the demonstration projects and should provide financial assistance that will permit industry to manage the projects in as commercial a manner as possible.

**Success at capping CO₂ emissions ultimately depends upon adherence to CO₂ mitigation policies by large developed and developing economies.** We see little progress to moving toward the needed international arrangements. Although the European Union has implemented a cap-and-trade program covering approximately half of its CO₂ emissions, the United States has not yet adopted mandatory policies at the federal level to limit CO₂ emissions. U.S. leadership in emissions reduction is a likely pre-requisite to substantial action by emerging economies.

A more aggressive U.S. policy appears to be in line with public attitudes. Americans now rank global warming as the number one environmental problem facing the country, and seventy percent of the American public think that the U.S. government needs to do more to reduce greenhouse gas emissions. Willingness to pay to solve this problem has grown 50 percent over the past three years.

Examination of current energy developments in China and India, however, indicate that it will be some time before carbon constraints will be adopted and implemented by China. The same is likely true for India.

An international system with modestly delayed compliance by emerging economies is manageable from the point of view of incremental accumulated CO₂ emissions. However, if other nations, and especially China and India, are to deal with this problem then CCS is a crucial technology for these countries as well, and the R&D and commercial demonstration focus proposed here is no less important in readying CCS for quick adoption if and when they begin to take more stringent control measures.

The central message of our study is that demonstration of technical, economic, and institutional features of carbon capture and sequestration at commercial scale coal combustion and conversion plants, will (1) give policymakers and the public confidence that a practical carbon mitigation control option exists, (2) shorten the deployment time and reduce the cost for carbon capture and sequestration should a carbon emission control policy be adopted, and (3) maintain opportunities for the lowest cost and most widely available energy form to be used to meet the world’s pressing energy needs in an environmentally acceptable manner.
Chapter 1 – Purpose of the Study

The risk of adverse climate change from global warming forced in part by growing greenhouse gas emissions is serious. While projections vary, there is now wide acceptance among the scientific community that global warming is occurring, that the human contribution is important, and that the effects may impose significant costs on the world economy. As a result, governments are likely to adopt carbon mitigation policies that will restrict CO₂ emissions; many developed countries have taken the first steps in this direction. For such carbon control policies to work efficiently, national economies will need to have many options available for reducing greenhouse gas emissions. As our earlier study — *The Future of Nuclear Power* — concluded, the solution lies not in a single technology but in more effective use of existing fuels and technologies, as well as wider adoption of alternative energy sources. This study — *The Future of Coal* — addresses one option, the continuing use of coal with reduced CO₂ emissions.

Coal is an especially crucial fuel in this uncertain world of future constraint on CO₂ emissions. Because coal is abundant and relatively cheap — $1–2 per million Btu, compared to $6–12 per million Btu for natural gas and oil — today, coal is often the fuel of choice for electricity generation and perhaps for extensive synthetic liquids production in the future in many parts of the world. Its low cost and wide availability make it especially attractive in major developing economies for meeting their pressing energy needs. On the other hand, coal faces significant environmental challenges in mining, air pollution (including both criteria pollutants and mercury), and importantly from the perspective of this study, emission of carbon dioxide (CO₂). Indeed coal is the largest contributor to global CO₂ emissions from energy use (41%), and its share is projected to increase.

This study examines the factors that will affect the use of coal in a world where significant constraints are placed on emissions of CO₂ and other greenhouse gases. We explore how the use of coal might adjust within the overall context of changes in the demand for and supply of different fuels that occur when energy markets respond to policies that impose a significant constraint on CO₂ emissions. Our purpose is to describe the technology options that are currently and potentially available for coal use in the generation of electricity if carbon constraints are adopted. In particular, we focus on carbon capture and sequestration (CCS) — the separation of the CO₂ combustion product that is produced in conjunction with the generation of electricity from coal and the transportation of the separated CO₂ to a site where the CO₂ is sequestered from the atmosphere. Carbon capture and sequestration add significant complexity and cost to coal conversion processes and, if deployed at large scale, will require considerable modification to current patterns of coal use.

We also describe the research, development, and demonstration (RD&D) that should be underway today, if these technology options are to be available for rapid deployment in the future, should the United States and other countries adopt carbon constraint policies. Our recommendations are restricted to what needs to be done to establish these technology
options to create viable choices for future coal use.

Our study does not address climate policy, nor does it evaluate or advocate any particular set of carbon mitigation policies. Many qualified groups have offered proposals and analysis about what policy measures might be adopted. We choose to focus on what is needed to create technology options with predictable performance and cost characteristics, if such policies are adopted. If technology preparation is not done today, policy-makers in the future will be faced with fewer and more difficult choices in responding to climate change.

We are also realistic about the process of adoption of technologies around the world. This is a global problem, and the ability to embrace a new technology pathway will be driven by the industrial structure and politics in the developed and developing worlds. In this regard, we offer assessments of technology adoption in China and India and of public recognition and concern about this problem in the United States.

The overarching goal of this series of MIT energy studies is to identify different combinations of policy measures and technical innovations that will reduce global emissions of CO₂ and other greenhouse gases by mid-century. The present study on The future of coal and the previous study on The future of nuclear power discuss two of the most important possibilities.

An outline of this study follows:

Chapter 2 presents a framework for examining the range of global coal use in all energy-using sectors out to 2050 under alternative economic assumptions. These projections are based on the MIT Emissions Predictions and Policy Analysis (EPPA) model. The results sharpen understanding of how a system of global markets for energy, intermediate inputs, and final goods and services would respond to imposition of a carbon charge (which could take the form of a carbon emissions tax, a cap and trade program, or other constraints that place a de facto price on carbon emissions) through reduced energy use, improvements in energy efficiency, switching to lower CO₂-emitting fuels or carbon-free energy sources, and the introduction of CCS.

Chapter 3 is devoted to examining the technical and likely economic performance of alternative technologies for generating electricity with coal with and without carbon capture and sequestration in both new plant and retrofit applications. We analyze air and oxygen driven pulverized coal, fluidized bed, and IGCC technologies for electricity production. Our estimates for the technical and environmental performance and for likely production cost are based on today’s experience.

Chapter 4 presents a comprehensive review of what is needed to establish CO₂ sequestration as a reliable option. Particular emphasis is placed on the need for geological surveys, which will map the location and capacity of possible deep saline aquifers for CO₂ injection in the United States and around the world, and for demonstrations at scale, which will help establish the regulatory framework for selecting sites, for measurement, monitoring and verification systems, and for long-term stewardship of the sequestered CO₂. These regulatory aspects will be important factors in gaining public acceptance for geological CO₂ storage.

Chapter 5 reports on the outlook for coal production and utilization in China and India. Most of our effort was devoted to China. China’s coal output is double that of the United States, and its use of coal is rapidly growing, especially in the electric power sector. Our analysis of the Chinese power sector examines the roles of central, provincial, and local actors in investment and operational decisions affecting the use of coal and its environmental impacts. It points to a set of practical constraints on the ability of the central government to implement restrictions on CO₂ emissions in the relatively near-term.

Chapter 6 evaluates the current DOE RD&D program as it relates to the key issues discussed
in Chapters 2, 3, and 4. It also makes recommendations with respect to the content and organization of federally funded RD&D that would provide greater assurance that CC&S would be available when needed.

**Chapter 7** reports the results of polling that we have conducted over the years concerning public attitudes towards energy, global warming and carbon taxes. There is evidence that public attitudes are shifting and that support for policies that would constrain CO₂ emissions is increasing.

**Chapter 8** summarizes the findings and presents the conclusions of our study and offers recommendations for making coal use with significantly reduced CO₂ emissions a realistic option in a carbon constrained world.

The reader will find technical primers and additional background information in the appendices to the report.
Chapter 2 — The Role of Coal in Energy Growth and CO₂ Emissions

INTRODUCTION

There are five broad options for reducing carbon emissions from the combustion of fossil fuels, which is the major contributor to the anthropogenic greenhouse effect:

- Improvements in the efficiency of energy use, importantly including transportation, and electricity generation;
- Increased use of renewable energy such as wind, solar and biomass;
- Expanded electricity production from nuclear energy;
- Switching to less carbon-intensive fossil fuels; and
- Continued combustion of fossil fuels, especially coal, combined with CO₂ capture and storage (CCS).

As stressed in an earlier MIT study of the nuclear option, if additional CO₂ policies are adopted, it is not likely that any one path to emissions reduction will emerge. All will play a role in proportions that are impossible to predict today. This study focuses on coal and on measures that can be taken now to facilitate the use of this valuable fuel in a carbon-constrained world. The purpose of this chapter is to provide an overview of the possible CO₂ emissions from coal burning over the next 45 years and to set a context for assessing policies that will contribute to the technology advance that will be needed if carbon emissions from coal combustion are to be reduced.

Coal is certain to play a major role in the world’s energy future for two reasons. First, it is the lowest-cost fossil source for base-load electricity generation, even taking account of the fact that the capital cost of a supercritical pulverized coal combustion plant (SCPC) is about twice that of a natural gas combined cycle (NGCC) unit. And second, in contrast to oil and natural gas, coal resources are widely distributed around the world. As shown in Figure 2.1, drawn from U.S. DOE statistics, coal reserves are spread between developed and developing countries.

The major disadvantages of coal come from the adverse environmental effects that accompany its mining, transport and combustion. Coal combustion results in greater CO₂ emissions than oil and natural gas per unit of heat output because of its relatively higher ratio of carbon to hydrogen and because the efficiency (i.e., heat rate) of a NGCC plant is higher than that of a SCPC plant. In addition to CO₂, the combustion-related emissions of coal generation include the criteria pollutants: sulfur dioxide (SO₂), nitrogen oxides (NO and NO₂), ...
jointly referred to as NOx), particulates, and mercury (Hg). Also, there are other aspects of coal and its use not addressed in this study. For example,

**Coal is not a single material.** Coal composition, structure, and properties differ considerably among mining locations. Table 2.1, also drawn from DOE data, shows the wide variation of energy content in the coals produced in different countries. These differences are a consequence of variation in chemical composition—notably water and ash content—which has an important influence on the selection of coal combustion technology and equipment. This point is discussed further in Chapter 3.

**Coal mining involves considerable environmental costs.** The environmental effects of mining include water pollution and land disturbance as well as the release of another greenhouse gas, methane (CH4), which is entrained in the coal. Also, mining involves significant risk to the health and safety of miners.

**Patterns of coal use differ among countries.** In mature economies, such as the United States, coal is used almost exclusively to generate electricity. In emerging economies, a significant portion of coal used is for industrial and commercial purposes as illustrated in Table 2.2 comparing coal use in the United States and China.

We begin this exploration of possible futures for coal with a brief overview of its current use and associated CO2 emissions, and projections to 2030, assuming there are no additional policies to restrict greenhouse gas emissions beyond those in place in 2007. For these business-as-usual projections we use the work of the U.S. Department of Energy’s Energy Information Administration (EIA). We then turn to longer-term projections and consider the consequences for energy markets and coal use of alternative policies that place a penalty on carbon emissions. For this latter part of the assessment, we apply an economic model developed at MIT, to be described below. This model shows that, among other effects of such policies, a carbon charge of sufficient magnitude will favor higher-efficiency coal-burning technologies and the application of carbon capture and sequestration (CSS), contributing to a reduction of emissions from coal and sustaining its use in the face of restrictions on CO2. In the longer-term projections, we focus on the U.S. and world totals, but we also include results for China to emphasize the role of large developing countries in the global outlook.

**THE OUTLOOK FOR COAL ABSENT ADDITIONAL CLIMATE POLICY**

Each year in its International Energy Outlook, the DOE/EIA reviews selected energy trends. Table 2.3 summarizes the EIA’s Reference Case projection of primary energy use (i.e., fossil fuels, hydro, nuclear, biomass, geothermal, wind and solar) and figures for coal consump-
The Role of Coal in Energy Growth and CO\textsubscript{2} Emissions

The projections are based on carbon emission regulations currently in effect. That is, developed countries that have ratified the Kyoto Protocol reduce their emissions to agreed levels through 2012, while developing economies and richer countries that have not agreed to comply with Kyoto (the United States and Australia) do not constrain their emissions growth. The report covers the period 1990 to 2030, and data are presented for countries grouped into two categories:

- **OECD members**, a richer group of nations including North America (U.S., Canada and Mexico), the EU, and OECD Asia (Japan, Korea, Australia and New Zealand).

- **Non-OECD nations**, a group of transition and emerging economies which includes Russia and other Non-OECD Europe and Eurasia, Non-OECD Asia (China, India and others), the Middle East, Africa, and Central and South America.

It can be seen that the non-OECD economies, though consuming far less energy than OECD members in 1990, are projected to surpass them within the next five to ten years. An even more dramatic picture holds for coal consumption. The non-OECD economies consumed about the same amount as the richer group in 1990, but are projected to consume twice as much by 2030. As would be expected, a similar picture holds for CO\textsubscript{2} emissions, as shown in Table 2.4. The non-OECD economies emitted less CO\textsubscript{2} than the mature ones up to the turn of the century, but because of their heavier dependence on coal, their emissions are expected to surpass those of the more developed group by 2010. The picture for emissions from coal burning, also shown in the table, is even more dramatic.

The qualitative conclusions to be drawn from these reference case EIA projections are summarized in Table 2.5, which shows the growth rates for energy and emissions for the period 2003–30. Worldwide energy consumption grows at about a 2% annual rate, with emerging economies increasing at a rate about three times that of OECD group. Emissions of CO\textsubscript{2} follow a similar pattern. Coal’s contribution to total CO\textsubscript{2} emissions had declined to about 37% early in the century, and (as can be seen in Table 2.4) this fraction is projected to grow to over 40% by 2030. Clearly any policy designed to constrain substantially the total CO\textsubscript{2} contribution to the atmosphere cannot succeed unless it somehow reduces the contribution from this source.

---

### Table 2.3 World Consumption of Primary Energy and Coal 1990–2030

<table>
<thead>
<tr>
<th></th>
<th>TOTAL PRIMARY ENERGY (QUADRILLION Btu)</th>
<th>TOTAL COAL (MILLION SHORT TONS)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>OECD (U.S.)</td>
<td>NON-OECD</td>
</tr>
<tr>
<td>1990</td>
<td>197 (85)</td>
<td>150</td>
</tr>
<tr>
<td>2003</td>
<td>234 (98)</td>
<td>186</td>
</tr>
<tr>
<td>2010</td>
<td>256 (108)</td>
<td>254</td>
</tr>
<tr>
<td>2015</td>
<td>270 (114)</td>
<td>294</td>
</tr>
<tr>
<td>2020</td>
<td>282 (120)</td>
<td>332</td>
</tr>
<tr>
<td>2025</td>
<td>295 (127)</td>
<td>371</td>
</tr>
<tr>
<td>2030</td>
<td>309 (134)</td>
<td>413</td>
</tr>
</tbody>
</table>


### Table 2.4 CO\textsubscript{2} Emissions by Region 1990–2030

<table>
<thead>
<tr>
<th></th>
<th>TOTAL EMISSIONS (BILLION METRIC TONS CO\textsubscript{2})</th>
<th>EMISSIONS FROM COAL (BILLION METRIC TONS CO\textsubscript{2})</th>
<th>COAL % OF TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>OECD (U.S.)</td>
<td>NON-OECD</td>
<td>TOTAL</td>
</tr>
<tr>
<td>1990</td>
<td>11.4 (4.98)</td>
<td>9.84</td>
<td>21.2</td>
</tr>
<tr>
<td>2003</td>
<td>13.1 (5.80)</td>
<td>11.9</td>
<td>25.0</td>
</tr>
<tr>
<td>2010</td>
<td>14.2 (6.37)</td>
<td>16.1</td>
<td>30.3</td>
</tr>
<tr>
<td>2015</td>
<td>15.0 (6.72)</td>
<td>18.6</td>
<td>33.6</td>
</tr>
<tr>
<td>2020</td>
<td>15.7 (7.12)</td>
<td>21.0</td>
<td>36.7</td>
</tr>
<tr>
<td>2025</td>
<td>16.5 (7.59)</td>
<td>23.5</td>
<td>40.0</td>
</tr>
<tr>
<td>2030</td>
<td>17.5 (8.12)</td>
<td>26.2</td>
<td>43.7</td>
</tr>
</tbody>
</table>

THE OUTLOOK FOR COAL UNDER POSSIBLE CO\textsubscript{2} PENALTIES

The MIT EPPA Model and Case Assumptions

To see how CO\textsubscript{2} penalties might work, including their implications for coal use under various assumptions about competing energy sources, we explore their consequences for fuel and technology choice, energy prices, and CO\textsubscript{2} emissions. Researchers at MIT’s Joint Program on the Science and Policy of Global Change have developed a model that can serve this purpose. Their Emissions Predictions and Policy Analysis (EPPA) model is a recursive-dynamic multi-regional computable general equilibrium (CGE) model of the world economy.\textsuperscript{6} It distinguishes sixteen countries or regions, five non-energy sectors, fifteen energy sectors and specific technologies, and includes a representation of household consumption behavior. The model is solved on a five-year time step to 2100, the first calculated year being 2005. Elements of EPPA structure relevant to this application include its equilibrium structure, its characterization of production sectors, the handling of international trade, the structure of household consumption, and drivers of the dynamic evolution of the model including the characterization of advanced or alternative technologies, importantly including carbon capture and storage (CCS).

The virtue of models of this type is that they can be used to study how world energy markets, as well as markets for other intermediate inputs and for final goods and services, would adapt to a policy change such as the adoption of a carbon emission tax, the establishment of cap-and-trade systems, or implementation of various forms of direct regulation of emissions. For example, by increasing the consumer prices of fossil fuels, a carbon charge would have broad economic consequences. These include changes in consumer behavior and in the sectoral composition of production, switching among fuels, a shift to low-carbon energy resources, and investment in more efficient ways to get the needed services from a given input of primary energy. A model like EPPA gives a consistent picture of the future energy market that reflects these dynamics of supply and demand as well as the effects of international trade.

Naturally, in viewing the results of a model of this type, a number of its features and input assumptions should be kept in mind. These include, for example, assumptions about:

- Population and productivity growth that are built into the reference projection;
- The representation of the production structure of the economy and the ease of substitution between inputs to production, and the behavior of consumers in response to changing prices of goods and services;
- The cost and performance of various technology alternatives, importantly for this study including coal technologies (which have been calibrated to the estimates in Chapters 3 and 4 below) and competitor generation sources;
- The length of time to turn over the capital stock, which is represented by capital vintages in this model;
- The assumed handling of any revenues that might result from the use of a carbon tax, or from permit auctions under cap-and-trade systems.\textsuperscript{7}

Thus our model calculations should be considered as illustrative, not precise predictions. The results of interest are not the absolute numbers in any particular case but the differences in outcomes for coal and CO\textsubscript{2} emissions among “what if” studies of different climate conditions.
policy regimes and assumptions about competing energy types. In the assessment below we test the response of the energy sector and its CO₂ emissions to alternative assumptions about the penalty imposed on emissions in various parts of the world and about the effect of two uncertain influences on coal use: the pace of nuclear power development and the evolution of natural gas markets.

To explore the potential effects of carbon policy, three cases are formulated: a reference or Business as Usual (BAU) case with no emissions policy beyond the first Kyoto period, and two cases involving the imposition of a common global price on CO₂ emissions. The two policy cases, a Low and a High CO₂ price path, are shown in Figure 2.2, with the CO₂ penalty stated in terms of 1997 $U.S. per ton of CO₂. This penalty or emissions price can be thought of as the result of a global cap-and-trade regime, a system of harmonized carbon taxes, or even a combination of price and regulatory measures that combine to impose the marginal penalties on emissions. The Low CO₂ Price profile corresponds to the proposal of the National Energy Commission, which we represent by applying its maximum or “safety valve” cap-and-trade price. It involves a penalty that begins in 2010 with $7 per ton CO₂ and increases at a real rate (e.g., without inflation) of 5% per year thereafter. The High CO₂ Price case assumes the imposition of a larger initial charge of $25 ton CO₂ in the year 2015 with a real rate of increase of 4% thereafter. One important question to be explored in the comparison of these two cases is the time when CSS technology may take a substantial role as an emissions reducing measure.

A second influence on the role of coal in future energy use is competition from nuclear generation. Here two cases are studied, shown in Table 2.6. In one, denoted as Limited Nuclear, it is assumed that nuclear generation, from its year 2000 level in the EPPA database of 1.95 million GWh, is held to 2.43 million GWh in 2050. At a capacity factor of 0.85, this corresponds to an expansion from a 1997 world installed total of about 261GW to some 327GW in 2050. The alternative case, denoted as Expanded Nuclear assumes that nuclear capacity grows to 1000GW over this period—a level identified as being feasible in the MIT Future of Nuclear Power study if certain conditions are met.

The third influence on the role of coal studied here concerns the evolution of real natural gas prices over time. The EPPA model includes a sub-model of resources and depletion of fossil fuels including natural gas, and one scenario, denoted EPPA-Ref Gas Price, applies the model’s own projection of gas prices (which differ by model regions) under the supply and demand conditions in the various simulations. In the Business-as-Usual (BAU) case with limited nuclear expansion, the real U.S. gas price

| Table 2.6 Alternative Cases for Nuclear Generation (Nuclear capacity in Million GWh/year) |
|---------------------------------|---------|---------|---------|
| REGION       | 1997    | LIMITED | EXPANDED |
| USA          | 0.57    | 0.58    | 2.23     |
| Europe       | 0.76    | 0.94    | 1.24     |
| Japan        | 0.28    | 0.42    | 0.48     |
| Other OECD   | 0.07    | 0.10    | 0.34     |
| FSU & EET    | 0.16    | 0.21    | 0.41     |
| China        | 0.00    | 0.00    | 0.75     |
| India        | 0.00    | 0.00    | 0.67     |
| Other Asia   | 0.10    | 0.19    | 0.59     |
| Rest of World| 0.00    | 0.00    | 0.74     |
| TOTAL        | 1.95    | 2.43    | 7.44     |
is projected to rise by 2050 by a factor of 3.6 over the base year (1997) price of $2.33 per Mcf, which implies a price of around $8.40 per Mcf in 2050 in 1997 prices. To test the effect of substantial new discovery and development of low-cost LNG transport systems, a second Low Gas Price case is explored. In this case the EPPA gas transport sub-model is overridden by a low-cost global transport system which leads to lower prices in key heavy gas-consuming regions. For example, with the Low Gas Price scenario, the real 2050 price multiple for the U.S. is only 2.4 over the base year, or a price of $5.60/Mcf in 1997 prices.11

Results Assuming Universal, Simultaneous Participation in CO₂ Emission Penalties

In order to display the relationships that underlie the future evolution of coal use, we begin with a set of policy scenarios where all nations adopt, by one means or another, to the carbon emissions penalties as shown in Figure 2.2. Were such patterns of emissions penalties adopted, they would be sufficient to stabilize global CO₂ emissions in the period between now and 2050. This result is shown in Figure 2.3 on the assumption of Limited Nuclear generation, and EPPA-Ref Gas Price.

If there is no climate policy, emissions are projected to rise to over 60 GtCO₂ by 2050. Under the High CO₂ Price path, by contrast, global emissions are stabilized by around 2015 at level of about 28 GtCO₂. If only the Low CO₂ Price path is imposed, emissions would not stabilize until around 2045 and then at a level of approximately 42 GtCO₂ per year.12

Figure 2.4 shows how global primary energy consumption adjusts in the EPPA model solution for the High CO₂ Price case with Limited Nuclear expansion and EPPA-Ref gas prices. The increasing CO₂ price leads to a reduction in energy demand over the decades and to adjustments in the composition of supply. For example, non-biomass renewables (e.g., wind) and commercial biomass (here expressed in terms of liquid fuel) both increase substantially.13 Most important for this discussion is the effect on coal use. When the carbon price increases in 2015, coal use is initially reduced. However, in 2025 coal with CCS begins to gain market share, growing steadily to 2050 (and beyond) and leading to a resurgence of global coal consumption.

A further global picture of coal use under these alternative CO₂ price assumptions, assuming Limited Nuclear capacity and EPPA-Ref Gas Price, is shown in Table 2.7. Under the Low CO₂ Price trajectory, coal’s contribution to 2050 global emissions is lowered from 32 GtCO₂ per year, to around 15 GtCO₂ per year while total coal consumption falls to 45% of its no-policy level (though still 100% above 2000 coal use). The contribution of carbon capture and storage (CCS) is relatively small in this case, because at this price trajectory CCS technology does not become economic until around 2035 or 2040, leading to a small market penetration by 2050. The picture differs substantially under assumption of the High CO₂ Price pattern. The contribution of CO₂ emissions from coal in 2050 is projected to be one-third that under the lower price path, yet coal use falls by only another 20% (and still remains 61% above the 2000 level). The key factor contributing to this result in 2050 can be seen in the third line in the table which shows the percentage of coal consumed using CCS technology. With higher CO₂ price levels early in the simulation period, CCS has the time and economic incentive to take a larger market share.
The point to take from Table 2.7 is that CO₂ mitigation policies at the level tested here will limit the expected growth of coal and associated emissions, but not necessarily restrict the production of coal below today’s level. Also, the long-term future for coal use, and the achievement in CO₂ emissions abatement, are sensitive to the development and public acceptance of CCS technology and the timely provision of incentives to its commercial application.

An assumption of expanded nuclear capacity to the levels shown in Table 2.6 changes the global picture of primary energy consumption and the proportion met by coal. This case is shown in Figure 2.5 which, like Figure 2.4, imposes the high CO₂ price trajectory and EPPA-Ref gas prices. The possibility of greater nuclear expansion supports a small increase in total primary energy under no-policy conditions but leaves the total energy essentially unchanged under the pressure of high CO₂ prices. The main adjustment is in the consumption of coal, which is reduced from 161 EJ to 120 EJ in 2050 through a substitution of nuclear generation for coal with and without CO₂ capture and storage.

Table 2.8 provides some individual country detail for these assumptions and shows the sensitivity of the EPPA results to assumptions about nuclear expansion and natural gas prices. The top rows of the table again present the global figures for coal use along with the figures for the U.S. and China. China’s coal consumption at 27 EJ is slightly above the 24 EJ in 2000, but without climate policy, China’s coal consumption is projected to increase to a level some 52% greater than that of the United States in 2050. On the other hand, the CO₂ penalty yields a greater percentage reduction in China than in the U.S.

By 2050 the High CO₂ Price has reduced Chinese use by 56%, but United States consumption is reduced by only 31%. The main reason for the difference in response is the composition of coal consumption, and to a lesser extent in a difference in the thermal efficiency of the electric power sectors of the two countries.

By 2050 in the reference scenario (EPPA-Ref Gas Price and Limited Nuclear), 54% of coal use in China is in non-electric power sectors compared with only 5% in the U.S. Under the

![Figure 2.4 Global Primary Energy Consumption under High CO₂ Prices (Limited Nuclear Generation and EPPA-Ref Gas Prices)](image)

![Figure 2.5 Global Primary Energy Consumption under High CO₂ Prices (Expanded Nuclear Generation and EPPA-Ref Gas Prices)](image)
High CO₂ Price policy, China’s share of coal consumption in the other sectors declines to 12%, while the U.S. share of coal consumption outside of the electricity sector drops to 3%. Within the electric sector, U.S. power plants are relatively more thermally efficient than in China, so opportunities to lower coal consumption in China’s power sector are greater.

Table 2.8 also displays the effect on coal use of alternative assumptions about the expansion of nuclear power. A growth of nuclear generating capacity at the level assumed in the Expanded Nuclear case directly displaces electricity from coal. For example, under Business as Usual the provision of expanded nuclear generation reduces 2050 global coal use from 448 to 405 EJ. This effect continues under the cases with penalties on CO₂ emissions. Moreover, if the influence of low gas prices is added to the greater nuclear penetration (a case shown in the bottom three rows) coal use declines further. Under these conditions, global coal use falls below 2000 levels under the High CO₂ Price case, and Chinese consumption would only reach its 2000 level in the years nearing 2050.

It can be seen in Figure 2.3 that in 2010 global CO₂ emissions are lower at the Low than at the High CO₂ Price scenario, whereas Table 2.7 indicates that by 2050 emissions are far lower at the stricter emissions penalty. This pattern is the result of the differential timing of the start of the mitigation policy and the influence of the two price paths on CCS, for which more detail is provided in Table 2.9. The lower CO₂ price path starts earlier and thus influences the early years, but under the high price path CCS enters earlier and, given the assumptions in the EPPA model about the lags in market penetration of such a new and capital-intensive technology, it has more time to gain market share. So, under Limited Nuclear growth and EPPA-Ref Gas Price, CCS-based generation under the High CO₂ Price reaches a global level ten times that under the Low CO₂ Price. An Expanded Nuclear sector reduces the total CCS installed in 2050 by about one-quarter.

Table 2.8 Coal Consumption

<table>
<thead>
<tr>
<th>SCENARIO</th>
<th>GAS PRICE</th>
<th>NUCLEAR</th>
<th>REGION</th>
<th>BAU (EJ)</th>
<th>LOW CO₂ PRICE (EJ)</th>
<th>HIGH CO₂ PRICE (EJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPPA-REF LIMITED</td>
<td>GLOBAL</td>
<td>100</td>
<td>448</td>
<td>200</td>
<td>161</td>
<td></td>
</tr>
<tr>
<td>EPPA-REF EXPANDED</td>
<td>GLOBAL</td>
<td>99</td>
<td>405</td>
<td>159</td>
<td>121</td>
<td></td>
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<tr>
<td>LOW EXPANDED</td>
<td>GLOBAL</td>
<td>95</td>
<td>397</td>
<td>129</td>
<td>89</td>
<td></td>
</tr>
<tr>
<td>US</td>
<td>24</td>
<td>58</td>
<td>42</td>
<td>40</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CHINA</td>
<td>27</td>
<td>88</td>
<td>37</td>
<td>39</td>
<td></td>
<td></td>
</tr>
<tr>
<td>US</td>
<td>23</td>
<td>44</td>
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<tr>
<td>CHINA</td>
<td>26</td>
<td>83</td>
<td>30</td>
<td>31</td>
<td></td>
<td></td>
</tr>
<tr>
<td>US</td>
<td>23</td>
<td>41</td>
<td>14</td>
<td>17</td>
<td></td>
<td></td>
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<tr>
<td>CHINA</td>
<td>26</td>
<td>80</td>
<td>13</td>
<td>31</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Assumes universal, simultaneous participation.

The Low Gas Price assumption has only a small effect on CCS when the penalty on CO₂ emissions is also low, but it has a substantial effect under the High CO₂ Price scenario because the low gas prices delay the initial adoption of CCS. The gas price has a less pronounced effect after 2050.

Accompanying these developments are changes in the price of coal. The EPPA model treats coal as a commodity that is imperfectly substitutable among countries (due to transport costs and the imperfect substitutability among various coals), so that it has a somewhat different price from place to place. Table 2.10 presents these prices for the U.S. and China. Under the no-policy BAU (with Limited Nuclear and EPPA-Ref Gas Price), coal prices are projected to increase by 47% in the U.S. and by 60% in China. Each of the changes explored—a charge on CO₂, expanded nuclear capacity or lower gas prices—would lower the demand for coal and thus its mine-mouth price. With high CO₂ prices, more nuclear and cheaper natural gas, coal prices are projected to be essentially the same in 2050 as they were in 2000.

Results Assuming Universal but Lagged Participation of Emerging Economies

The previous analysis assumes that all nations adopt the same CO₂ emission charge schedule. Unfortunately, this is a highly unlikely
outcome. The Kyoto Protocol, for example, sets emission reduction levels only for the developed and transition (Annex B) economies. The emissions of developing nations (classified as Non-Annex B), including China and India, are not constrained by the Protocol and at present there is no political agreement about how these nations might participate in a carbon regime of CO₂ emissions restraint.16 Clearly if the fast growing developing economies do not adopt a carbon charge, the world level of emissions will grow faster than presented above.

To test the implications of lagged participation by emerging economies we explore two scenarios of delay in their adherence to CO₂ control regimes. They are shown in Figure 2.6. The High CO₂ Price trajectory from the earlier figures is repeated in the figure, and this price path is assumed to be followed by the Annex B parties. The trajectory marked 10-year Lag has the developing economies maintaining a carbon charge that developed economies adopted ten years previously. The trajectory marked Temp Lag assumes that after 20 years the developing economies have returned to the carbon charge trajectory of the developed economies. In this latter case, developing economies would go through a transition period of a higher rate of increase in CO₂ prices than the 4% rate that is simulated for the developed economies and eventually (around 2045), the same CO₂ price level would be reached as in the case of universal participation. Note that these scenarios are not intended as realistic portrayals of potential future CO₂ markets. They simply provide a way to explore the implications of lagged accession to a climate agreement, however it might be managed.

Figure 2.7 projects the consequences of these different assumptions about the adherence of developing economies to a program of CO₂ penalties assuming the Limited Nuclear expansion and EPPA-Ref Gas Price path. First of all, the figure repeats the BAU case from before, and a case marked High CO₂ Price, which is the same scenario as before when all nations follow the High CO₂ Price path. The Annex

### Table 2.9 Coal Capture and Sequestration Plants: Output (EJ) and Percentage of Coal Consumption

<table>
<thead>
<tr>
<th>SCENARIO</th>
<th>REGION</th>
<th>BAU</th>
<th>LOW CO₂ PRICE</th>
<th>HIGH CO₂ PRICE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2000</td>
<td>2050</td>
<td>2050</td>
</tr>
<tr>
<td>EPPA-Ref</td>
<td>Limited</td>
<td>Global</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>US</td>
<td>0</td>
<td>0</td>
<td>0.1 (&lt;1%)</td>
<td>9.4 (76%)</td>
</tr>
<tr>
<td>China</td>
<td>0</td>
<td>0</td>
<td>1.8 (16%)</td>
<td>11.0 (88%)</td>
</tr>
<tr>
<td>EPPA-Ref</td>
<td>Expanded</td>
<td>Global</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>US</td>
<td>0</td>
<td>0</td>
<td>0.1 (1%)</td>
<td>6.6 (86%)</td>
</tr>
<tr>
<td>China</td>
<td>0</td>
<td>0</td>
<td>1.6 (18%)</td>
<td>8.5 (85%)</td>
</tr>
<tr>
<td>Low</td>
<td>Expanded</td>
<td>Global</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>US</td>
<td>0</td>
<td>0</td>
<td>0.1 (&lt;1%)</td>
<td>1.1 (22%)</td>
</tr>
<tr>
<td>China</td>
<td>0</td>
<td>0</td>
<td>1.5 (36%)</td>
<td>8.2 (85%)</td>
</tr>
</tbody>
</table>

Assumes universal, simultaneous participation.

### Table 2.10 Coal Price Index (2000 = 1)

<table>
<thead>
<tr>
<th>SCENARIO</th>
<th>REGION</th>
<th>BAU</th>
<th>LOW CO₂ PRICE</th>
<th>HIGH CO₂ PRICE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2000</td>
<td>2050</td>
<td>2050</td>
</tr>
<tr>
<td>EPPA-Ref</td>
<td>Limited</td>
<td>US</td>
<td>1.00</td>
<td>1.47</td>
</tr>
<tr>
<td></td>
<td></td>
<td>China</td>
<td>1.00</td>
<td>1.60</td>
</tr>
<tr>
<td>EPPA-Ref</td>
<td>Expanded</td>
<td>US</td>
<td>1.00</td>
<td>1.39</td>
</tr>
<tr>
<td></td>
<td></td>
<td>China</td>
<td>1.00</td>
<td>1.66</td>
</tr>
<tr>
<td>Low</td>
<td>Expanded</td>
<td>US</td>
<td>1.00</td>
<td>1.38</td>
</tr>
<tr>
<td></td>
<td></td>
<td>China</td>
<td>1.00</td>
<td>1.64</td>
</tr>
</tbody>
</table>

Assumes universal, simultaneous participation.

### Figure 2.6 Scenarios of Penalties on CO₂ Emissions: High Price for Annex B Nations and Two Patterns of Participation by Non-Annex B Parties ($/t CO₂)
B Only case considers the implications if the Non-Annex B parties never accept any CO2 penalty, in which case total emissions continue to grow although at a slower pace than under BAU.

The next case assumes developing economies adhere to a “high” carbon price but with a lag of ten years after developed economies. The trend is clear: (1) if developing economies do not adopt a carbon charge, stabilization of emissions by 2050 cannot be achieved under this price path; and (2) if developing economies adopt a carbon charge with a time lag, stabilization is possible, but it is achieved at a later time and at a higher level of global emissions, depending upon the precise trajectory adopted by the developing economies. For example, if developing economies maintain a carbon tax with a lag of 10 years behind the developed ones, then cumulative CO2 emissions through 2050 will be 123 GtCO2 higher than if developing economies adopted the simulated carbon charge with no lag. If developing economies adopted the carbon tax with a ten-year lag but converged with the developed economies tax 20 years later (noted as Temp Lag in Figure 2.6 but not shown in Figure 2.7) then cumulative CO2 emissions through 2050 would be 97 GtCO2 higher than if developing economies adopted the tax with no lag. The significance of these degrees of delay can be understood in comparison with cumulative CO2 emissions under the High CO2 Price case over the period 2000 to 2050, which is estimated to be 1400 GtCO2 under the projections used here.17

THE ROLE OF CCS IN A CARBON CONSTRAINED WORLD

The importance of CCS for climate policy is underlined by the projection for coal use if the same CO2 emission penalty is imposed and CCS is not available, as shown in Table 2.11. Under Limited Nuclear expansion the loss of CCS would lower coal use in 2050 by some 28% but increase global CO2 emissions by 14%. With Expanded Nuclear capacity, coal use and emissions are lower than in the limited nuclear case and the absence of CCS has the same effect. Depending on the nuclear assumption the loss of the CCS option would raise 2050 CO2 emissions by between 10% and 15%.

This chart motivates our study’s emphasis on coal use with CCS. Given our belief that coal will continue to be used to meet the world’s energy needs, the successful adoption of CCS is critical to sustaining future coal use in a carbon-constrained world. More significantly considering the energy needs of developing countries, this technology may be an essential component of any attempt to stabilize global emissions of CO2, much less to meet the Climate Convention’s goal of stabilized atmospheric concentrations. This conclusion holds even for plausible levels of expansion of nuclear power or for policies stimulating the other approaches to emissions mitigation listed at the outset of this chapter.

CONCLUDING OBSERVATIONS

A central conclusion to be drawn from our examination of alternative futures for coal is that if carbon capture and sequestration is successfully adopted, utilization of coal likely will expand even with stabilization of CO2 emissions. Though not shown here, extension of these emissions control scenarios further into the future shows continuing growth
in coal use provided CCS is available. Also to be emphasized is that market adoption of CCS requires the incentive of a significant and widely applied charge for CO₂ emissions.

All of these simulations assume that CCS will be available, and proven socially and environmentally acceptable, if and when more widespread agreement is reached on imposing a charge on CO₂ emissions. This technical option is not available in this sense today, of course. Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially leading to long delays in implementation of this important option. Therefore these simulation studies underscore the need for development work now at a scale appropriate to the technological and societal challenge. The task of the following chapters is to explore the components of such a program—including generation and capture technology and issues in CO₂ storage—in a search for the most effective and efficient path forward.

### Table 2.11 Coal Consumption (EJ) and Global CO₂ Emissions (Gt/yr) in 2000 and 2050 with and without Carbon Capture and Storage

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Coal Use: Global</strong></td>
<td>100</td>
<td>448</td>
<td>161</td>
<td>116</td>
<td>121</td>
<td>78</td>
</tr>
<tr>
<td><strong>U.S.</strong></td>
<td>24</td>
<td>58</td>
<td>40</td>
<td>28</td>
<td>25</td>
<td>13</td>
</tr>
<tr>
<td><strong>China</strong></td>
<td>27</td>
<td>88</td>
<td>39</td>
<td>24</td>
<td>31</td>
<td>17</td>
</tr>
<tr>
<td><strong>Global CO₂ Emissions</strong></td>
<td>24</td>
<td>62</td>
<td>28</td>
<td>32</td>
<td>26</td>
<td>29</td>
</tr>
<tr>
<td><strong>CO₂ Emissions from Coal</strong></td>
<td>9</td>
<td>32</td>
<td>5</td>
<td>9</td>
<td>3</td>
<td>6</td>
</tr>
</tbody>
</table>

Assumes universal, simultaneous participation, High CO₂ prices and EPPA-Ref gas prices.

### CITATIONS AND NOTES

4. In China there has been a history of multiple official estimates of coal production and upward revisions for previous years. Some government statistics show higher numbers for the 2003 and 2004 quantities in Tables 2.1 and 2.2.
5. This charge may be imposed as a result of a tax on carbon content or as the result of a cap-and-trade system that would impose a price on CO₂ emissions. In the remainder of the paper, the terms charge, price, tax, and penalty are used interchangeably to denote the imposition of a cost on CO₂ emissions.
6. The MIT EPPA model is described by Paltsev, S., J.M. Reilly, H.D. Jacoby, R.S. Eckaus, J. McFarland, M. Sarofim, M. Asadoorian & M. Babiker, The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 4, MIT Joint Program on the Science and Policy of Global Change, Report No 125, August 2005. The model as documented there has been extended by the implementation of an improved representation of load dispatching in the electric sector—an improvement needed to properly assess the economics of CCS technology. It is assumed that all new coal plants have efficiencies corresponding to supercritical operation, that U.S. coal fired generation will meet performance standards for SO₂ and NOₓ, and Hg similar to those under the EPA’s Clean Air Interstate Rule and Clean Air Mercury Rules.
7. The simulations shown here assume any revenues from taxes or auctioned permits are recycled directly to consumers. Alternative formulations, such as the use of revenues to reduce other distorting taxes, would have some effect on growth and emissions but would not change the insights drawn here from the comparison of policy cases.
8. The Kyoto targets are not imposed in either the projections of either the EIA or the EPPA simulations because the target beyond 2012 is not known nor are the methods by which the first commitment period targets might actually be met. Imposition of the existing Kyoto targets would have an insignificant effect on the insights to be drawn from this analysis. Note also that neither the EIA analyses nor the EPPA model are designed to try to represent short-term fluctuations in fuel markets, as occurred for example in the wake of supply disruptions in 2005.


10. The range of scenarios may be compared with the DOE/IEA IEO (2006), which projects nuclear generation of 3.29 million GWh in 2030 with no difference between its Reference, High and Low growth cases.

11. These paths for the U.S. may be compared with the DOE/IEA Annual Energy Outlook (2006) which projects a 65% increase in U.S. natural gas prices from 2000 to 2030, whereas EPPA projects a 100% rise over this period. On the other hand our Low price assumption shows 70% growth, very close to the AEO projection for the U.S.

12. In these EPPA calculations the focus is on emissions, but it is important to remember that higher emission levels translate into higher global mean greenhouse gas concentrations and it is the concentration of greenhouse gases that influences global climate. These carbon penalties succeed in stabilizing carbon emissions, not atmospheric concentrations which would continue to rise over the period shown in Figure 2.3.

13. The global 2050 biomass production of 48 EJ is expressed in the figure in liquid fuel units. The implied quantity of dry biomass input is approximately 120 EJ. Following the standard accounting convention, the global primary input to nuclear power is expressed in equivalent heat units of fossil electricity. Because fossil generation is becoming more (thermally) efficient in this projection nuclear power appears not to be increasing in the figure when in fact it is growing according to the “limited” case in Table 2.6. The same procedure is applied to hydroelectric and non-biomass renewable sources of electricity.

14. Calibration of the EPPA model has applied the official data on Chinese coal as reported in DOE/IEA IEO. Higher estimates of recent and current consumption are also available from Chinese government agencies (see Endnote 4) and if they prove correct then both Chinese and world coal consumption and emissions are higher than shown in these results. In addition, there is uncertainty in all these projections, but the uncertainty is especially high for an economy in rapid economic transition, like China.

15. The EPPA model projects a slightly more rapid coal price growth under these conditions than does the DOE/EIA. Its Annual Energy Outlook (2006) shows a 20% minemouth price increase 2000 to 2030 for the U.S., whereas EPPA projects about a 10% increase over this period.

16. The Kyoto regime permits “cooperative development measures” that allow Annex B countries to earn emission reduction credits by investing in CO2 reduction projects in emerging economies. The quantitative impact that CDM might make to global CO2 reductions is not considered in our study, and CDM credits are not included in this version of the EPPA model.

17. If official statistics of recent Chinese coal consumption prove to be an underestimate (see Endnotes 4 and 14), then very likely the emissions shown in Figure 2.6, importantly including the excess burden of a 10-year lag by developing countries, would be increased.
INTRODUCTION

In the U.S., coal-based power generation is expanding again; in China, it is expanding very rapidly; and in India, it appears on the verge of rapid expansion. In all these countries and worldwide, the primary generating technology is pulverized coal (PC) combustion. PC combustion technology continues to undergo technological improvements that increase efficiency and reduce emissions. However, technologies favored for today’s conditions may not be optimum under future conditions. In particular, carbon dioxide capture and sequestration in coal-based power generation is an important emerging option for managing carbon dioxide emissions while meeting growing electricity demand, but this would add further complexity to the choice of generating technology.

The distribution of coal-based generating plants for the U.S. is shown in Figure 3.1. Most of the coal-based generating units in the U.S. are between 20 and 55 years old; the average age of the fleet is over 35 years[1]. Coal-based generating units less than 35 years old average about 550 MW; older generating units are typically smaller. With current life-extension capabilities, many of these units could, on-average, operate another 30+ years. Units that are less than about 50 years old are essentially all air-blown, PC combustion units. The U.S. coal fleet average generating efficiency is about 33%, although a few, newer generating units exceed 36% efficiency [2][3]. Increased generating efficiency is important, since it translates directly into lower criteria pollutant emissions (at a given removal efficiency) and lower carbon dioxide emissions per kW·h of electricity generated.

GENERATING TECHNOLOGIES — OVERVIEW

This chapter evaluates the technologies that are either currently commercial or will be commercially viable in the near term for electricity generation from coal. It focuses primarily on the U.S., although the analysis is more broadly applicable. We analyze these generating technologies in terms of the cost of electricity produced by each, without and with carbon dioxide (CO₂) capture, and their applicability, efficiency, availability and reliability. Power generation from coal is subject to a large number of variables which impact technology choice, operating efficiency, and cost of electricity (COE) produced [4]. Our approach here was to pick a point set of conditions at which to compare each of the generating technologies, using a given generating unit design model to provide consistency. We then consider how changes from this point set of conditions, such as changing coal type, impact the design, operation, and cost of electricity (COE) for each technology. We also consider emissions control and retrofits for CO₂ capture for each technology. Appendix 3.A summarizes coal type and quality issues, and their impact.

For the technology comparisons in this chapter, each of the generating units considered was a green-field unit which contained all the emissions control equipment required to operate slightly below current, low, best-demonstrated criteria emissions performance levels.
To evaluate the technologies on a consistent basis, the design performance and operating parameters for these generating technologies were based on the Carnegie Mellon Integrated Environmental Control Model, version 5.0 (IECM) [5] which is a modeling tool specific to coal-based power generation [6] [7]. The units all use a standard Illinois #6 bituminous coal, a high-sulfur, Eastern U.S. coal with a moderately high heating value (3.25 wt% sulfur & 25,350 kJ/kg (HHV)). Detailed analysis is given in Table A-3.B.1 [5] (Appendix 3.B).

**GENERATING EFFICIENCY**  The fraction of the thermal energy in the fuel that ends up in the net electricity produced is the generating efficiency of the unit [8]. Typical modern coal units range in thermal efficiency from 33% to 43% (HHV). Generating efficiency depends on a number of unit design and operating parameters, including coal type, steam temperature and pressure, and condenser cooling water temperature [9]. For example, a unit in Florida will generally have a lower operating efficiency than a unit in northern New England or in northern Europe due to the higher cooling water temperature in Florida. The difference in generating efficiency could be 2 to 3 percentage points. Typically, units operated at near capacity exhibit their highest efficiency; unit cycling and operating below capacity result in lower efficiency.

**LEVELIZED COST OF ELECTRICITY**  The levelized cost of electricity (COE) is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors. Levelized COE is comprised of three components: capital charge, operation and maintenance costs, and fuel costs. Capital cost is generally the largest component of COE. This study calculated the capital cost component of COE by applying a carrying charge factor of 15.1% to the total plant cost (TPC). Appendix 3.C provides the basis for the economics discussed in this chapter.

**AIR-BLOWN COAL COMBUSTION GENERATING TECHNOLOGIES**  In the next section we consider the four primary air-blown coal generating technologies that compose essentially all the coal-based power generation units in operation today and being built. These include PC combustion using subcritical, supercritical, or ultra-supercritical steam cycles designed for Illinois #6 coal and circulating fluid-bed (CFB) combustion designed for lignite. Table 3.1 summariz-
es representative operating performance and economics for these air-blown coal combustion generating technologies. Appendix 3.C provides the basis for the economics. PC combustion or PC generation will be used to mean air-blown pulverized coal combustion for the rest of this report, unless explicitly stated to be oxy-fuel PC combustion for oxygen-blown PC combustion.

### Table 3.1 Representative Performance And Economics For Air-Blown PC Generating Technologies

<table>
<thead>
<tr>
<th>PERFORMANCE</th>
<th>SUBCRITICAL PC</th>
<th>SUPERCRITICAL PC</th>
<th>ULTRA-SUPERCRITICAL PC</th>
<th>SUBCRITICAL CFB*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>W/O CAPTURE</td>
<td>W/ CAPTURE</td>
<td>W/O CAPTURE</td>
<td>W/O CAPTURE</td>
</tr>
<tr>
<td>Heat rate (1), Btu/kW-h</td>
<td>9,950</td>
<td>13,600</td>
<td>8,870</td>
<td>11,700</td>
</tr>
<tr>
<td>Generating efficiency (HHV)</td>
<td>34.3%</td>
<td>25.1%</td>
<td>38.5%</td>
<td>29.3%</td>
</tr>
<tr>
<td>Coal feed, kg/h</td>
<td>208,000</td>
<td>284,000</td>
<td>185,000</td>
<td>243,000</td>
</tr>
<tr>
<td>CO2 emitted, kg/h</td>
<td>466,000</td>
<td>63,600</td>
<td>415,000</td>
<td>54,500</td>
</tr>
<tr>
<td>CO2 captured at 90%, kg/h (2)</td>
<td>0</td>
<td>573,000</td>
<td>0</td>
<td>491,000</td>
</tr>
<tr>
<td>CO2 emitted, g/kWe-h</td>
<td>931</td>
<td>127</td>
<td>830</td>
<td>109</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COSTS</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Plant Cost, $/kW, (3)</td>
<td>1,280</td>
<td>2,230</td>
<td>1,330</td>
<td>2,140</td>
</tr>
<tr>
<td>Inv. Charge, ¢/kWe-h @ 15.1% (4)</td>
<td>2.60</td>
<td>4.52</td>
<td>2.70</td>
<td>4.34</td>
</tr>
<tr>
<td>Fuel, ¢/kWe-h @ $1.50/MMBtu</td>
<td>1.49</td>
<td>2.04</td>
<td>1.33</td>
<td>1.75</td>
</tr>
<tr>
<td>O&amp;M, ¢/kWe-h</td>
<td>0.75</td>
<td>1.60</td>
<td>0.75</td>
<td>1.60</td>
</tr>
<tr>
<td>COE, ¢/kWe-h</td>
<td>4.84</td>
<td>8.16</td>
<td>4.78</td>
<td>7.69</td>
</tr>
<tr>
<td>Cost of CO2 avoided (5) vs. same technology w/o capture, $/tonne</td>
<td>41.3</td>
<td>40.4</td>
<td>41.1</td>
<td>39.7</td>
</tr>
<tr>
<td>Cost of CO2 avoided (5) vs. supercritical w/o capture, $/tonne</td>
<td>48.2</td>
<td>40.4</td>
<td>34.8</td>
<td>42.8</td>
</tr>
</tbody>
</table>

**Basis:** 500 MW net output. Illinois # 6 coal (61.2% wt C, HHV = 25,350 kJ/kg), 85% capacity factor

1. Efficiency = 3414 Btu/kW-h/(heat rate);
2. 90% removal used for all capture cases
3. Based on design studies and estimates done between 2000 & 2004, a period of cost stability, updated to 2005$ using CPI inflation rate. 2007 cost would be higher because of recent rapid increases in engineering and construction costs, up 25 to 30% since 2004.
4. Annual carrying charge of 15.1% from EPRI-TAG methodology for a U.S. utility investing in U.S. capital markets; based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge
5. Does not include costs associated with transportation and injection/storage
6. CFB burning lignite with HHV = 17,400 kJ/kg and costing $1.00/million Btu

**PULVERIZED COAL COMBUSTION POWER GENERATION: WITHOUT CO2 CAPTURE**

### SUBCRITICAL OPERATION
In a pulverized coal unit, the coal is ground to talcum-powder fineness, and injected through burners into the furnace with combustion air [10-12]. The fine coal particles heat up rapidly, undergo pyrolysis and ignite. The bulk of the combustion air is then mixed into the flame to completely burn the coal char. The flue gas from the boiler passes through the flue gas clean-up units to remove particulates, SOx, and NOx. The flue gas exiting the clean-up section meets criteria
pollutant permit requirements, typically contains 10–15% CO₂ and is essentially at atmospheric pressure. A block diagram of a subcritical PC generating unit is shown in Figure 3.2. Dry, saturated steam is generated in the furnace boiler tubes and is heated further in the superheater section of the furnace. This high-pressure, superheated steam drives the steam turbine coupled to an electric generator. The low-pressure steam exiting the steam turbine is condensed, and the condensate pumped back to the boiler for conversion into steam.

Subcritical operation refers to steam pressure and temperature below 22.0 MPa (~3200 psi) and about 550° C (1025° F) respectively. Subcritical PC units have generating efficiencies between 33 to 37% (HHV), dependent on coal quality, operations and design parameters, and location.

Key material flows and conditions for a 500 MWₑ subcritical PC unit are given in Figure 3.2 [5, 13]. The unit burns 208,000 kg/h (208 tonnes/h [14]) of coal and requires about 2.5 million kg/h of combustion air. Emissions control was designed for 99.9% PM and 99+% SOₓ reductions and greater than about 90% NOₓ reduction. Typical subcritical steam cycle conditions are 16.5 MPa (~2400 psi) and 540° C (1000° F) superheated steam. Under these operating conditions (Figure 3.2), IECM projects an efficiency of 34.3% (HHV) [15]. More detailed material flows and operating conditions are given in Appendix 3.B, Figure A-3.B.2, and Table 3.1 summarizes the CO₂ emissions.

The coal mineral matter produces about 22,800 kg/h (23 tonnes/h) of fly and bottom ash. This can be used in cement and/or brick manufacture. Desulfurization of the flue gas produces about 41,000 kg/h (41 tonnes/h) of wet solids that may be used in wallboard manufacture or disposed of in an environmentally safe way.

**SUPERCRITICAL AND ULTRA-SUPERCRITICAL OPERATION** Generating efficiency is increased by designing the unit for operation at higher steam temperature and pressure. This represents a movement from subcritical to supercritical to ultra-supercritical steam parameters [16]. Supercritical steam cycles were not commercialized until the late 1960s, after the necessary materials technologies had been developed. A number of supercritical units were built in the U.S. through the 1970’s and early 80’s, but they were at the limit of the then-available materials and fabrication capabilities, and some problems were encountered [17]. These problems have been overcome for supercritical operating conditions, and supercritical units are now highly reliable. Under supercritical conditions, the supercritical fluid is expanded through the high-pressure stages of a steam turbine, generating electricity. To recharge the steam properties and increase the amount of power generated, after expansion through the high-pressure turbine stages, the

---

**Figure 3.2 Subcritical 500 MWₑ, Pulverized Coal Unit without CO₂ Capture**
Reheat, single or double, increases the cycle efficiency by raising the mean temperature of heat addition to the cycle.

Supercritical electricity generating efficiencies range from 37 to 40% (HHV), depending on design, operating parameters, and coal type. Current state-of-the-art supercritical PC generation involves 24.3 MPa (~3530 psi) and 565°C (1050° F), resulting in a generating efficiency of about 38% (HHV) for Illinois #6 coal.

Meanwhile, new materials capabilities have been further expanding the potential operating range. To take advantage of these developments, the power industry, particularly in Europe and Japan, continues to move to higher steam pressure and temperature, primarily higher temperatures. Operating steam cycle conditions above 565°C (>1050° F) are referred to as ultra-supercritical. A number of ultra-supercritical units operating at pressures to 32 MPa (~4640 psi) and temperatures to 600/610°C (1112-1130° F) have been constructed in Europe and Japan [18]. Operational availability of these units to date has been comparable to that of subcritical plants. Current materials research and development is targeting steam cycle operating conditions of 36.5 to 38.5 MPa (~5300-5600 psi) and temperatures of 700-720°C (1290-1330° F)[19]. These conditions should increase generating efficiency to the 44 to 46% (HHV) range for bituminous coal, but require further materials advances, particularly for manufacturing, field construction, and repair.

Figure 3.3 is a block diagram of a 500 MWₜ ultra-supercritical PC generating unit showing key flows. The coal/combustion side of the boiler and the flue gas treatment are the same as for a subcritical boiler. Coal required to generate a given amount of electricity is about 21% lower than for subcritical generation, which means that CO₂ emissions per MWₜ·h are reduced by 21%. The efficiency projected for these design operating conditions is 43.3% (HHV) (Figure 3.3) vs. 34.3% for subcritical conditions. More detailed material and operating information is given in Appendix 3.B. Table 3.1 summarizes the performance for subcritical, supercritical, and ultra-supercritical operation.

FLUID-BED COMBUSTION A variation on PC combustion is fluid-bed combustion in which coal is burned with air in a fluid bed, typically a circulating fluid bed (CFB)[20-22]. CFBs are best suited to low-cost waste fuels and low-quality or low heating value coals. Crushed coal and limestone are fed into the bed, where the limestone undergoing calcination to produce lime (CaO). The fluid bed consists mainly of lime, with a few percent coal, and recirculated coal char. The bed operates at significantly lower temperatures, about 427°C (800° F), which thermodynamically favors low NOₓ formation.
and SO₂ capture by reaction with CaO to form CaSO₄. The steam cycle can be subcritical and potentially supercritical, as with PC combustion, and generating efficiencies are similar. The primary advantage of CFB technology is its capability to capture SO₂ in the bed, and its flexibility to a wide range of coal properties, including coals with low heating value, high-ash coals and low-volatile coals, and to changes in coal type during operation. Several new lignite-burning CFB units have been constructed recently, and CFBs are well suited to co-firing biomass [23].

The performance data for the CFB unit in Table 3.1 is based on lignite rather than Illinois #6 coal. The lignite has a heating value of 17,400 kJ/kg and low sulfur. The coal feed rate is higher than for the other technologies because of the lower heating value of the lignite. Appendix 3.B gives a detailed process schematic for CFB generation.

COAL TYPE AND QUALITY EFFECTS

Coal type and quality impact generating unit technology choice and design, generating efficiency, capital cost, performance, and COE (Appendix 3.A). Boiler designs today usually encompass a broader range of typical coals than initially intended to provide future flexibility. Single coal designs are mostly limited to mine-mouth plants, which today are usually only lignite, subbituminous, or brown coal plants. The energy, carbon, moisture, ash, and sulfur contents, as well as ash characteristics, all play an important role in the value and selection of coal, in its transportation cost, and in the technology choice for power generation. For illustration, Table 3.2 gives typical values and ranges for various coal properties as a function of coal type. Although most of the studies available are based on bituminous coals, a large fraction of the power generated in the U.S. involves Western subbituminous coals (>35%), such as Powder River Basin, because of its low sulfur content.

Each of these coal properties interacts in a significant way with generation technology to affect performance. For example, higher sulfur content reduces PC generating efficiency due to the added energy consumption and operating costs to remove SO₂ from the flue gas. High ash content requires PC design changes to manage erosion. High ash is a particular problem with Indian coals. Fluid-bed combustion is well suited to high-ash coals, low-carbon coal waste, and lignite. Several high-efficiency, ultra-supercritical and supercritical PC generating units have recently been commissioned in Germany burning brown coal or lignite, and several new CFB units have been constructed in Eastern Europe, the U.S., Turkey and India burning lignite and in Ireland burning peat[23, 24].

Coal types with lower energy content and higher moisture content significantly affect capital cost and generating efficiency. About 50% of U.S. coal is sub-bituminous or lignite. Using bituminous Pittsburgh #8 as the reference, PC units designed for Powder River Basin (PRB) coal and for Texas lignite have an estimated 14% and 24% higher capital cost respectively. Generating efficiency decreases but by a smaller percentage (Appendix 3.A, Figure A-3.A.3) [25]. However, the lower cost of coal types with lower heating value can offset the impact of this increased capital cost and decreased efficiency, thus, resulting in very little impact on COE. Using average 2004 mine-mouth coal prices and PC generation, the COE for Illinois #6, PRB, and Texas lignite is equal to or less than that for Pittsburgh #8 (Appendix 3.A, Figure A-3.A.4).

U.S. CRITERIA POLLUTANT IMPACTS

Although coal-based power generation has a negative environmental image, advanced PC plants have very low emissions; and PC emissions control technology continues to improve and will improve further (Appendix 3.D). It is not clear when and where the ultimate limits of flue gas control will be reached. In the U.S., particulate removal, via electrostatic precipita-
Flue gas desulfurization has been added to less than one-third of U.S. coal-based generating capacity \[2\], and post-combustion NOx control is practiced on about 10% of the coal-based generating capacity.

The Clean Air Act (1990) set up a cap and trade system for SOx \[26\] and established emissions reductions guidelines for NOx. This has helped produce a 38% reduction in total SOx emissions over the last 30 years, while coal-based power generation grew by 90%. Total NOx emissions have been reduced by 25% over this period. Recent regulations, including NAAQS[27], the Clean Air Interstate Rule (CAIR) \[28\], and the Clean Air Mercury Rule (CAMR) \[29\] will require an additional 60% reduction in total SOx emissions and an additional 45% reduction in total NOx emissions nationally by 2020. During this period, coal-based generation is projected to grow about 35%. Mercury reduction initially comes with SOx abatement; additional, mandated reductions come after 2009. NAAQS have produced a situation in which permitting a new coal generating unit requires extremely low emissions of particulate matter (PM), SOx, and NOx, driven by the need to meet stringent, local air quality requirements, essentially independent of national emissions caps.

Newly permitted coal-fired PC units routinely achieve greater than 99.5% particulate control, and removal efficiencies greater than 99.9% are achievable at little additional cost. Wet flue-gas desulfurization (FGD) can achieve 95% SOx removal without additives and 99% SOx removal with additives \[30\]. Selective catalytic reduction (SCR), combined with low-NOx combustion technology, routinely achieves 90+% NOx reduction over non-controlled emissions levels. New, advanced PC units in the U.S. are currently achieving criteria pollutant emissions reductions consistent with the performance outlined above and have emissions levels that are at or below the emissions levels achieved by the best PC units in Japan and Europe (Appendix 3.D).

Today, about 25% of the mercury in the coal burned is removed by the existing flue gas treatment technologies in place, primarily with the fly ash via electrostatic precipitators (ESP) or fabric filters. Wet FGD achieves 40-60% mercury removal; and when it is combined with SCR, mercury removal could approach 95% for bituminous coals \[31\]. For subbituminous coals, mercury removal is typically less than 40%, and may be significantly less for lignite, even when the flue gas clean-up technologies outlined above are in use. However, with activated carbon or brominated activated carbon injection removal rates can be increased to ~90% \[31\]. Optimization of existing technologies and new technology innovations can be expected to achieve > 90% mercury removal on most if not all coals within the next 10-15 years.

Table 3.3 gives the estimated incremental impact on the COE of the flue gas treatment technologies to meet the low emissions levels that are the design basis of this study, vs. a PC unit without controls. The impact of achieving these levels of control is about 1.0 €/kW\textsubscript{e}-h
or about 20% of the total COE from a highly-controlled PC unit. Although mercury control is not explicitly addressed here, removal should be in the 60-80% range for bituminous coals, including Illinois #6 coal, and less for subbituminous coals and lignite. We estimate that the incremental costs to meet CAIR and CAMR requirements and for decreasing the PM, SO₂, and NOₓ emissions levels by a factor of 2 from the current best demonstrated emissions performance levels used for Table 3.3 would increase the cost of electricity by about an additional 0.22 ¢/kWe-h (Appendix 3.D, Table A-3D.4). The total cost of emissions control is still less than 25% of the cost of the electricity produced. Meeting the Federal 2015 emissions levels is not a question of control technology capabilities but of uniform application of current technology. Meeting local emissions requirements may be a different matter.

PULVERIZED COAL COMBUSTION GENERATING TECHNOLOGY: WITH CO₂ CAPTURE

CO₂ capture with PC combustion generation involves CO₂ separation and recovery from the flue gas, at low concentration and low partial pressure. Of the possible approaches to separation [32], chemical absorption with amines, such as monoethanolamine (MEA) or hindered amines, is the commercial process of choice [33, 34]. Chemical absorption offers high capture efficiency and selectivity for air-blown units and can be used with sub-, super-, and ultra-supercritical generation as illustrated in Figure 3.4 for a subcritical PC unit. The CO₂ is first captured from the flue gas stream by absorption into an amine solution in an absorption tower. The absorbed CO₂ must then be stripped from the amine solution via a temperature increase, regenerating the solution for recycle to the absorption tower. The recovered CO₂ is cooled, dried, and compressed to a supercritical fluid. It is then ready to be piped to storage.

CO₂ removal from flue gas requires energy, primarily in the form of low-pressure steam for the regeneration of the amine solution. This reduces steam to the turbine and the net power output of the generating plant. Thus, to maintain constant net power generation the coal input must be increased, as well as the size of the boiler, the steam turbine/generator, and the equipment for flue gas clean-up, etc. Absorption solutions that have high CO₂ binding energy are required by the low concentration of CO₂ in the flue gas, and the energy requirements for regeneration are high.

A subcritical PC unit with CO₂ capture (Figure 3.4), that produces 500 MWₑ net power, requires a 37% increase in plant size and in coal feed rate (76,000 kg/h more coal) vs. a

Table 3.3 Estimated Incremental Costs for a Pulverized Coal Unit to Meet Today’s Best Demonstrated Criteria Emissions Control Performance Vs. No Control

<table>
<thead>
<tr>
<th></th>
<th>CAPITAL COST [$/kWe]</th>
<th>O&amp;M [¢/kWe-h]</th>
<th>COE [¢/kWe-h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM Control</td>
<td>40</td>
<td>0.18</td>
<td>0.26</td>
</tr>
<tr>
<td>NOₓ</td>
<td>25 (50 – 90)</td>
<td>0.10 (0.05 – 0.15)</td>
<td>0.15 (0.15 – 0.33)</td>
</tr>
<tr>
<td>SO₂</td>
<td>150 (100 – 200)</td>
<td>0.22 (0.20 – 0.25)</td>
<td>0.52 (0.40 – 0.65)</td>
</tr>
<tr>
<td>Incremental control cost</td>
<td>215</td>
<td>0.50</td>
<td>0.93</td>
</tr>
</tbody>
</table>

a. Incremental capital costs for a typical, new-build plant to meet today’s low emissions levels. Costs for low heating value coals will be somewhat higher
b. O&M costs are for typical plant meeting today’s low emissions levels. Costs will be somewhat higher for high-sulfur and low heating value coals.
c. Incremental COE impact, bituminous coal
d. Particulate control by ESP or fabric filter included in the base unit costs
e. Range is for retrofits and depends on coal type, properties, control level and local factors
f. When added to the “no-control” COE for SC PC, the total COE is 4.78 ¢/kWe-h
500 MWₜ unit without CO₂ capture (Figure 3.2). The generating efficiency is reduced from 34.3% to 25.1% (Table 3.1). The primary factors in efficiency reduction associated with addition of CO₂ capture are illustrated in Figure 3.5. The thermal energy required to recover CO₂ from the amine solution reduces the efficiency by 5 percentage points. The energy required to compress the CO₂ from 0.1 MPa to about 15 MPa (to a supercritical fluid) is the next largest factor, reducing the efficiency by 3.5 percentage points. All other energy requirements amount to less than one percentage point.

An ultra-supercritical PC unit with CO₂ capture (Figure 3.6) that produces the same net power output as an ultra-supercritical PC unit without CO₂ capture (Figure 3.3) requires a 27% increase in unit size and in coal feed rate (44,000 kg/h more coal). Figure 3.7 illustrates the main factors in efficiency reduction associated with addition of CO₂ capture to an ultra-supercritical PC unit. The overall efficiency reduction is 9.2 percentage points in both cases, but the ultra-supercritical, non-capture unit starts at a sufficiently high efficiency that with CO₂ capture, its efficiency is essentially the same as that of the subcritical unit without CO₂ capture.

COST OF ELECTRICITY FOR AIR-BLOWN PULVERIZED COAL COMBUSTION

The cost of electricity (COE), without and with CO₂ capture, was developed for the competing technologies analyzed in this report through a detailed evaluation of recent design studies, combined with expert validation. Appendix 3.C lists the studies that formed the basis for our report (Table A-3.C.2), provides more detail on each, and details the approach used. The largest and most variable component of COE among the studies is the capital charge, which is dependent on the total plant (or unit) cost (TPC) and the cost of capital. Figure 3.8 shows...
the min, max, and mean of the estimated TPC for each technology expressed in 2005 dollars. Costs are for a 500 MWe plant and are given in $/kWe net generating capacity.

In addition to the variation in TPC, each of these studies used different economic and operating parameter assumptions resulting in a range in the capital carrying cost, in the O&M cost, and in the fuel cost. The differences in these assumptions among the studies account for much of the variability in the reported COE. The COE from these studies is shown in Figure 3.9, where the “as-reported” bars show the min, max, and mean in the COE for the different technologies as reported in the studies in the dollars of the study year. Appendix 3.C provides more detail.

To compare the studies on a more consistent basis, we recalculated the COE for each of the studies using the normalized economic and operating parameters listed in Table 3.4. O&M costs are generally considered to be technology and report-specific and were not changed in this analysis. Other factors that contribute to variation include regional material and labor costs, and coal quality impacts. The “normalized” bars in Figure 3.9 summarize the results of this analysis of these design studies.

The variation in “as-reported” COE for non-capture PC combustion is small because of the broad experience base for this technology. Significant variation in COE exists for the CO₂ capture cases due to the lack of commercial data. The normalized COE values are higher for most of the cases because we used a higher fuel price and put all cost components in 2005 dollars.

To develop the COE values for this report, we took the TPC numbers from the design studies (Figure 3.8), adjusted them to achieve internal consistency (e.g. SubC PC<SC PC<USC PC), then compared our TPC numbers with industry consensus group numbers [35] and made secondary adjustments based on ratios and deltas from these numbers. This produced the TPC values in Table 3.1. Using these TPC values...
numbers, the parameters in Table 3.4, and estimated O&M costs, we calculated the COE for each technology, and these are given in Table 3.1.

Total plant costs shown above and in Table 3.1 were developed during a period of price stability [2000-2004] and were incremented by CPI inflation to 2005$. These costs and the deltas among them were well vetted, broadly accepted, and remain valid in comparing costs of different generating technologies. However, significant cost inflation from 2004 levels due to increases in engineering and construction costs including labor, steel, concrete and other consumables used for power plant construction, has been between 25 and 30%. Thus, a SCPC unit with an estimated capital cost of $1330 (Table 3.1) is now projected at $1660 to $1730/ kW in 2007$. Because we have no firm data on how these cost increases will affect the cost of the other technologies evaluated in this report, the discussion that follows is based on the cost numbers in Table 3.1, which for relative comparison purposes remain valid.

For PC generation without CO₂ capture, the COE decreases from 4.84 to 4.69 ¢/kW-h from subcritical to ultra-supercritical technology because efficiency gains outweigh the additional capital cost (fuel cost component decreases faster than the capital cost component increases). Historically, coal cost in the U.S. has been low enough that the economic choice has been subcritical PC. The higher coal costs in Europe and Japan have driven the choice of higher-efficiency generating technologies, supercritical and more recently ultra-supercritical. For the CFB case, the COE is similar to that for the PC cases, but this is because cheaper lignite is the feed, and emissions control is less costly. The CFB design used here does not achieve the very low criteria emissions achieved by our PC design. For Illinois #6 and comparable emissions limits, the COE for the CFB would be significantly higher.

The increase in COE in going from no-capture to CO₂ capture ranges from 3.3 ¢/kW-h for subcritical generation to 2.7 ¢/kW-h for ultra-supercritical generation (Table 3.1). Over half of this increase is due to higher capital carrying charge resulting from the increased boiler and steam turbine size and the added CO₂ capture, recovery, and compression equipment. About two thirds of the rest is due to higher O&M costs associated with the increased operational scale per kW, and with CO₂ capture and recovery. For air-blown PC combustion technologies, the cost of avoided CO₂ is about $41 per tonne. These costs are for capture, compression and drying, and do not include the pipeline, transportation and sequestration costs.

The largest cause of the efficiency reduction observed with CO₂ capture for air-blown PC generation (Figure 3.5 and 3.7) is the energy
required to regenerate the amine solution (recovering the CO₂), which produces a 5 percentage point efficiency reduction. If this component could be reduced by 50% with an efficient, lower-energy capture technology, the COE for supercritical capture would be reduced by about 0.5 $/kWₜ-h to about 7.2 $/kWₜ-h and by about 0.4 $/kWₜ-h for ultrasupercritical generation. This would reduce the CO₂ avoided cost to about $30 per tonne, a reduction of over 25%.

**RETORET FOR CO₂ CAPTURE**

Because of the large coal-based PC generating fleet in place and the additional capacity that will be constructed in the next two decades, the issue of retrofitting for CO₂ capture is important to the future management of CO₂ emissions. For air-blown PC combustion units, retrofit includes the addition of a process unit to the back end of the flue-gas system to separate and capture CO₂ from the flue gas, and to dry and compress the CO₂ to a supercritical fluid, ready for transport and sequestration. Since the existing coal fleet consists of primarily subcritical units, another option is to rebuild the boiler/steam system, replacing it with high efficiency supercritical or ultrasupercritical technology, including post-combustion CO₂ capture. Appendix 3.E provides a more-detailed analysis of retrofits and rebuilds.

For an MEA retrofit of an existing subcritical PC unit, the net electrical output can be derated by over 40%, e.g., from 500 MWₑ to 294 MWₑ [36]. In this case, the efficiency decrease is about 14.5 percentage points (Appendix 3.E) compared to about 9.2 percentage points for purpose-built subcritical PC units, one no-capture and the other capture (Table 3.1). With the retrofit, the steam required to regenerate the absorbing solution to recover the CO₂ (Figure 3.4), unbalances the rest of the plant so severely that the efficiency is reduced another 4 to 5 percentage points. In the retrofit case, the original boiler is running at full design capacity, but the original steam turbine is operating at about 60% design rating, which is well off its efficiency optimum. Due to the large power output reduction (41% derating), the retrofit capital cost is estimated to be $1600 per kWₑ [36]. This was for a specific
unit with adequate space; however, retrofit costs are expected to be highly dependent on location and unit specifics. If the original unit is considered fully paid off, we estimate the COE after retrofit could be slightly less than that for a new purpose-built PC unit with CO₂ capture. However, an operating plant will usually have some residual value, and the reduction in unit efficiency and output, increased on-site space requirements and unit downtime are all complex factors not fully accounted for in this analysis. Based on our analysis, we conclude that retrofits seem unlikely.

Another approach, though not a retrofit, is to rebuild the core of a subcritical PC unit, installing supercritical or ultra-supercritical technology along with post-combustion CO₂ capture. Although the total capital cost for this approach is higher, the cost/kWₑ is about the same as for a subcritical retrofit. The resultant plant efficiency is higher, consistent with that of a purpose-built unit with capture; the net power output can essentially be maintained; and the COE is about the same due to the overall higher efficiency. We estimate that an ultra-supercritical rebuild with MEA capture will have an efficiency of 34% and produce electricity for 6.91 ¢/kWₑ-h (Appendix 3.E). We conclude that rebuilds including CO₂ capture appear more attractive than retrofits, particularly if they upgrade low-efficiency PC units with high-efficiency technology, including CO₂ capture.

**CAPTURE-READY** A unit can be considered capture-ready if, at some point in the future, it can be retrofitted for CO₂ capture and sequestration and still be economical to operate [37]. Thus, capture-ready design refers to designing a new unit to reduce the cost of and to facilitate adding CO₂ capture later or at least to not preclude addition of capture later. Capture-ready has elements of ambiguity associated with it because it is not a specific design, but includes a range of investment and design decisions that might be undertaken during unit design and construction. Further, with an uncertain future policy environment, significant pre-investment for CO₂ capture is typically not economically justified [38]. However, some actions make sense. Future PC plants should employ the highest economically efficient technology and leave space for future capture equipment if possible, because this makes retrofits more attractive. Siting should consider proximity to geologic storage.

**OXYGEN-BLOWN COAL-BASED POWER GENERATION**

The major problems with CO₂ capture from air-blown PC combustion are due to the need to capture CO₂ from flue gas at low concentration and low partial pressure. This is mainly due to the large amount of nitrogen in the flue gas, introduced with the combustion air. Another approach to CO₂ capture is to substitute oxygen for air, essentially removing most of the nitrogen. We refer to this as oxy-fuel PC combustion. A different approach is to gasify the coal and remove the CO₂ prior to combustion. Each of these approaches has advantages and disadvantages, but each offers opportunities for electricity generation with reduced CO₂-capture costs. We consider these approaches next in the form of oxy-fuel PC combustion and Integrated Gasification Combined Cycle (IGCC) power generation.

Table 3.5 summarizes representative performance and economics for oxygen-blown coal-based power generation technologies. Oxy-fuel combustion and IGCC were evaluated using the same bases and assumptions used for the PC combustion technologies (Table 3.1). In this case the estimates are for the Nᵗʰ unit or plant where N is a relatively small number, < 10. In this report, we use gasification and IGCC to mean oxygen-blown gasification or oxygen-blown IGCC. If we mean air-blown gasification, it will be explicitly stated.

**OXY-FUEL PULVERIZED COAL (PC) COMBUSTION**

This approach to capturing CO₂ from PC units involves burning the coal with ~95%
pure oxygen instead of air as the oxidant[39-41]. The flue gas then consists mainly of carbon dioxide and water vapor. Because of the low concentration of nitrogen in the oxidant gas (95% oxygen), large quantities of flue gas are recycled to maintain design temperatures and required heat fluxes in the boiler, and dry coal-ash conditions. Oxy-fuel enables capture of CO₂ by direct compression of the flue gas but requires an air-separation unit (ASU) to supply the oxygen. The ASU energy consumption is the major factor in reducing the efficiency of oxy-fuel PC combustion. There are no practical reasons for applying oxy-fuel except for CO₂ capture.

A block diagram of a 500 MWₑ oxy-fuel generating unit is shown in Figure 3.10 with key material flows shown. Boiler and steam cycle are supercritical. The coal feed rate is higher than that for supercritical PC without capture because of the power consumption of the air separation unit but lower than that for a supercritical PC with MEA CO₂ capture (Table 3.1). In this design, wet FGD is used prior to recycle to remove 95% of the SOₓ to avoid boiler corrosion problems and high SOₓ concentration in the downstream compression/separation equipment. Non-condensables are removed from the compressed flue gas via a two-stage flash. The composition requirements (purity) of the CO₂ stream for transport and geological injection are yet to be established. The

### Table 3.5  Representative Performance and Economics for Oxy-Fuel Pulverized Coal and IGCC Power Generation Technologies, Compared with Supercritical Pulverized Coal

<table>
<thead>
<tr>
<th></th>
<th>SUPERCRITICAL PC W/O CAPTURE</th>
<th>SC PC-OXY W/CAPTURE</th>
<th>IGCC W/O CAPTURE</th>
<th>IGCC W/CAPTURE</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PERFORMANCE</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat rate (1), Btu/kWₑ-h</td>
<td>8,868</td>
<td>11,652</td>
<td>11,157</td>
<td>8,891</td>
</tr>
<tr>
<td>Generating efficiency (HHV)</td>
<td>38.5%</td>
<td>29.3%</td>
<td>30.6%</td>
<td>38.4%</td>
</tr>
<tr>
<td>Coal fed, kg/h</td>
<td>184,894</td>
<td>242,950</td>
<td>232,628</td>
<td>185,376</td>
</tr>
<tr>
<td>CO₂ emitted, kg/h</td>
<td>414,903</td>
<td>54,518</td>
<td>52,202</td>
<td>415,983</td>
</tr>
<tr>
<td>CO₂ captured at 90%, kg/h (2)</td>
<td>0</td>
<td>490,662</td>
<td>469,817</td>
<td>0</td>
</tr>
<tr>
<td>CO₂ emitted, g/kWₑ-h (2)</td>
<td>830</td>
<td>109</td>
<td>104</td>
<td>832</td>
</tr>
<tr>
<td><strong>COSTS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost (3), $/kWₑ</td>
<td>1,330</td>
<td>2,140</td>
<td>1,900</td>
<td>1,430</td>
</tr>
<tr>
<td>Inv Charge, ¢/kWₑ-h @ 15.1% (4)</td>
<td>2.70</td>
<td>4.34</td>
<td>3.85</td>
<td>2.90</td>
</tr>
<tr>
<td>Fuel, ¢/kWₑ-h @ $1.50/MMBtu</td>
<td>1.33</td>
<td>1.75</td>
<td>1.67</td>
<td>1.33</td>
</tr>
<tr>
<td>O&amp;M, ¢/kWₑ-h</td>
<td>0.75</td>
<td>1.60</td>
<td>1.45</td>
<td>0.90</td>
</tr>
<tr>
<td>COE, ¢/kWₑ-h</td>
<td>4.78</td>
<td>7.69</td>
<td>6.98</td>
<td>5.13</td>
</tr>
<tr>
<td>Cost of CO₂ avoided vs. same technology w/o capture (5), $/tonne</td>
<td>40.4</td>
<td>30.3</td>
<td>19.3</td>
<td></td>
</tr>
<tr>
<td>Cost of CO₂ avoided vs. supercritical technology w/o capture (5), $/tonne</td>
<td>40.4</td>
<td>30.3</td>
<td>24.0</td>
<td></td>
</tr>
</tbody>
</table>

**Basis:** 500 MWₑ plant net output, Illinois # 6 coal (61.2 wt % C, HHV = 25,350 kJ/kg), & 85% capacity factor; for oxy-fuel SC PC CO₂ for sequestration is high purity; for IGCC, GE radiant cooled gasifier for no-capture case and GE full-quench gasifier for capture case.

(1) efficiency = (3414 Btu/kWₑ-h)/(heat rate)
(2) 90% removal used for all capture cases
(3) Based on design studies done between 2000 & 2004, a period of cost stability, updated to 2005$ using CPI inflation rate. Refers to the Nth plant where N is less than 10. 2007 cost would be higher because of recent rapid increases of engineering and construction costs, up to 30% since 2004.
(4) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 39.2% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge
(5) Does not include costs associated with transportation and injection/storage
generating efficiency is 30.6% (HHV), which is about 1 percentage point higher than supercritical PC with MEA CO₂ capture. Current design work suggests that the process can be further simplified with SOₓ and NOₓ removal occurring in the downstream compression & separation stage at reduced cost [42]. Further work is needed.

Figure 3.11 shows the parasitic energy requirements for oxy-fuel PC generation with CO₂ capture. Since the steam cycle is supercritical for the oxy-fuel case, supercritical PC is used as the comparison base. The oxy-fuel PC unit has a gain over the air-driven PC case due to improved boiler efficiency and reduced emissions control energy requirements, but the energy requirement of the ASU, which produces a 6.4 percentage point reduction, outweighs this efficiency improvement. The overall efficiency reduction is 8.3 percentage points from supercritical PC. More efficient oxygen separation technology would have a significant impact.

A key unresolved issue is the purity requirements of the supercritical CO₂ stream for geological injection (sequestration). Our design produces a highly-pure CO₂ stream, similar to that from the PC capture cases, but incurs additional cost to achieve this purity level. If this additional purification were not required for transport and geologic sequestration of the CO₂, oxy-fuel PC combustion could gain up to one percentage point in efficiency, and the COE could be reduced by up to 0.4 ¢/kWe-h.

Oxy-fuel PC combustion is in early commercial development but appears to have considerable potential. It is under active pilot-scale development [43, 44]; Vattenfall plans a 30 MWth CO₂-free coal combustion plant for 2008 start-up[43]; Hamilton, Ontario is developing a 24 MWe oxy-fuel electricity generation project [45]; and other projects can be expected to be announced.

**ECONOMICS** Because there is no commercial experience with oxy-fuel combustion and lack of specificity on CO₂ purity requirements for transport and sequestration in a future regulatory regime, the TPC in the limited design studies ranged broadly [13, 39, 41, 46] (Appendix 3.C, Table A-3.C.2, Figure A-3.C.1).
Only the Parsons study estimated the COE [13]. As with PC combustion, we reviewed the available design studies (Appendix 3.C), our plant component estimate of costs, and external opinion of TPC to arrive at a projected TPC (Table 3.5). We estimated generating efficiency to be 30.6% from the Integrated Environmental Control Model[5]. We applied our normalization economic and operating parameters (Table 3.4) to calculate a COE of 6.98 ¢/kWe-h (Table 3.5). There may be some upside potential in these numbers if supercritical CO₂ stream purity can be relaxed and design efficiencies gained, but more data are needed.

**RETROFITS**  Oxy-fuel is a good option for retrofitting PC and FBC units for capture since the boiler and steam cycle are less affected by an oxy-fuel retrofit; the major impact being an increased electricity requirement for the auxiliaries, particularly the ASU. Bozzuto estimated a 36% derating for an oxy-fuel retrofit vs. a 41% derating for MEA capture on the same unit [36]. In summary, the oxy-fuel retrofit option costs about 40% less on a $/kWₐ basis, is projected to produce electricity at 10% to 15% less than an MEA retrofit, and has a significantly lower CO₂ avoidance cost (Appendix 3.E). Oxy-fuel rebuild to improve efficiency is another option and appears to be competitive with a high-efficiency MEA rebuild [47].

**INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)**

Integrated gasification combined cycle (IGCC) technology produces electricity by first gasifying coal to produce syngas, a mixture of hydrogen and carbon monoxide[48, 49]. The syngas, after clean-up, is burned in a gas turbine which drives a generator. Turbine exhaust goes to a heat recovery generator to raise steam which drives a steam turbine generator. This combined cycle technology is similar to the technology used in modern natural gas fired combined-cycle power plants. Appendix 3.B provides more detail on gasification.

The key component in IGCC is the gasifier, for which a number of different technologies have been developed and are classified and summarized in Table 3.6.

Gasifier operating temperature depends on whether the ash is to be removed as a solid, dry ash or as a high-temperature liquid (slag). Outlet temperature depends on the flow regime and extent of mixing in the gasifier. For the current IGCC plants, oxygen-blown, entrained-flow gasifiers are the technology of choice, although other configurations are being evaluated.

Four 275 to 300 MWₑ coal-based IGCC demonstration plants, which are all in commercial operation, have been built in the U.S. and in Europe, each with government financial support [50][33]. Five large IGCC units (250 to 550 MWₑ) are operating in refineries gasifying asphalt and refinery wastes [51, 52]; a smaller one (180 MWₑ) is operating on petroleum coke. The motivation for pursuing IGCC is the potential for better environmental performance at a lower marginal cost, easier CO₂ capture for sequestration, and higher efficiency. However, the projected capital cost (discussed below) and operational availability of today’s IGCC technology make it difficult to compete with conventional PC units at this time.
IGCC: WITHOUT CO₂ CAPTURE

There are several commercial gasifiers which can be employed with IGCC [53] (see Appendix 3.B for details). A block diagram of a 500 MWₜ IGCC unit using a radiant cooling/quench gasifier is shown in Figure 3.12. Finely ground coal, either dry or slurried with water, is introduced into the gasifier, which is operated at pressures between 3.0 and 7.1 MPa (440 to 1050 psi), along with oxygen and water. Oxygen is supplied by an air separation unit (ASU). The coal is partially oxidized raising the temperature to between 1340 and 1400 °C. This assures complete carbon conversion by rapid reaction with steam to form an equilibrium gas mixture that is largely hydrogen and carbon monoxide (syngas). At this temperature, the coal mineral matter melts to form a free-flowing slag. The raw syngas exits the gasification unit at pressure and relatively high temperature, with radiative heat recovery raising high-pressure steam. Adequate technology does not exist to clean-up the raw syngas at high temperature. Instead, proven technologies for gas clean-up require near-ambient temperature. Thus, the raw syngas leaving the gasifier can be quenched by injecting water, or a radiant cooler, and/or a fire-tube (convective) heat exchanger may be used to cool it to the required temperature for removal of particulate matter and sulfur.

The clean syngas is then burned in the combustion turbine. The hot turbine exhaust gas is used to raise additional steam which is sent to the steam turbine in the combined-cycle power block for electricity production. For the configuration shown (See Box 3.1), the overall generating efficiency is 38.4% (HHV), but coal and gasifier type will impact this number.

**Table 3.6 Classification and Characteristics of Gasifiers**

<table>
<thead>
<tr>
<th>MOVING BED</th>
<th>FLUID BED</th>
<th>ENTRAINMENT FLOW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outlet temperature</td>
<td>Low (425-600 °C)</td>
<td>Moderate (900-1050 °C)</td>
</tr>
<tr>
<td>Oxidant demand</td>
<td>Low</td>
<td>Moderate</td>
</tr>
<tr>
<td>Ash conditions</td>
<td>Dry ash or slagging</td>
<td>Dry ash or agglomerating</td>
</tr>
<tr>
<td>Size of coal feed</td>
<td>6-50 mm</td>
<td>6-10 mm</td>
</tr>
<tr>
<td>Acceptability of fines</td>
<td>Limited</td>
<td>Good</td>
</tr>
<tr>
<td>Other characteristics</td>
<td>Methane, tars and oils present in syngas</td>
<td>Low carbon conversion</td>
</tr>
</tbody>
</table>

**Figure 3.12 500 MWₜ IGCC Unit without CO₂ Capture**
IGCC: WITH PRE-COMBUSTION CO₂ CAPTURE

Applying CO₂ capture to IGCC requires three additional process units: shift reactors, an additional CO₂ separation process, and CO₂ compression and drying. In the shift reactors, CO in the syngas is reacted with steam over a catalyst to produce CO₂ and hydrogen. Because the gas stream is at high pressure and has a high CO₂ concentration, a weakly CO₂-binding physical solvent, such as the glymes in Selexol, can be used to separate out the CO₂. Reducing the pressure releases the CO₂ and regenerates the solvent, greatly reducing the energy requirements for CO₂ capture and recovery compared to the MEA system. Higher pressure in the gasifier improves the energy efficiency of both the separation and CO₂ compression steps. The gas stream to the turbine is now predominantly hydrogen, which requires turbine modifications for efficient operation.

The block diagram with key material flows for a 500 MWₑ IGCC unit designed for CO₂ capture is shown in Figure 3.13. For CO₂ capture, a full-quench gasifier is currently considered the optimum configuration. The overall generating efficiency is 31.2% which is a 7.2 percentage point reduction from the IGCC system without CO₂ capture. Adding CO₂ capture requires a 23% increase in the coal feed rate. This compares with coal feed rate increases of 27% for ultra-supercritical PC and 37% for subcritical PC when MEA CO₂ capture is used.

Figure 3.14 illustrates the major impacts on efficiency of adding CO₂ capture to IGCC. CO₂ compression and water gas shift each have...
significant impacts. CO₂ compression is about two-thirds that for the PC cases because the CO₂ is recovered at an elevated pressure. Energy is required in the form of steam for shift reaction. The energy required for CO₂ recovery is lower than for the PC case because of the higher pressures and higher CO₂ concentrations, resulting in less energy intensive separation processes. The total efficiency reduction for IGCC is 7.2 percentage points as compared with 9.2 percentage points for the PC cases. This smaller delta between the no-capture and the capture cases is one of the attractive features of IGCC for application to CO₂ capture.

**COST OF ELECTRICITY** We analyzed the available IGCC design studies, without and with CO₂ capture, just as we did for PC generation, to arrive at a TPC and our estimate of the COE (Appendix 3.C). There was considerable variation (~$400/kWe from min to max) in the TPC from the design studies for both no-capture and capture cases as shown in Figure A-3.C.2 (Appendix 3.C). Each estimate is for a 500 MWₑ plant and includes the cost of a spare gasifier. This variation is not surprising in that the studies involved two gasifier types, and there is little commercial experience against which to benchmark costs. There is a variation (min to max) of 0.8 ¢/kWₑ·h for no capture and 0.9 ¢/kWₑ·h for CO₂ capture in the “as-reported” COE in the studies (Figure A-3.C.4, Appendix 3.C).

We used the same approach to estimate the COE for IGCC as for air-blown PC [54]. For IGCC w/o capture, the COE is about 0.4 cent/kWₑ·h higher than for supercritical PC generation, driven by somewhat higher capital and operating costs. The increase in COE for IGCC when CO₂ capture is added is about 1.4 ¢/kWₑ·h. This is about half the increase projected for amine capture with supercritical PC. The cost of avoided CO₂ is about $20 per tonne which is about half that for air-blown PC technology. Oxy-fuel PC is in between air-blown PC with amine capture and IGCC with CO₂ capture, based on currently available data.

The COE values developed for this report compare well with the “normalized” values
from the design studies evaluated (Figure A-3.C.3 and A-3.C.4). Our values are close to the mean values for super-critical PC without and with capture. For IGCC, our values are at the high end of the range of the other design studies. Our COE for oxy-fuel PC is slightly higher than the “as-reported” values, although it is important to note that oxy-fuel data are based on only two published studies [44, 55].

To further validate the findings in this section, we compared our results with the COE estimates from several sources and summarize these results in Table 3.7. Supercritical PC without capture is set as the reference at 1.0. This suggests that without CO2 capture, the cost of electricity from IGCC will be from 5 to 11% higher than from supercritical PC. When CO2 capture is considered, the cost of electricity produced by IGCC will be from 30 to 50% over that of supercritical PC without capture, or 25 to 40% over that of IGCC without capture (Table 3.7). However, for supercritical PC with CO2 capture, the cost of electricity is expected to increase by 60 to 85% over the cost for supercritical PC without capture. These numbers are for green-field plants; they are also for the Nth plant where N is less than 10; and they are based on cost estimates from the relatively stable 2000–2004 cost period.

**COAL TYPE AND QUALITY EFFECTS** Although gasification can handle almost any carbon-containing material, coal type and quality can have a larger effect on IGCC than on PC generation. IGCC units operate most effectively and efficiently on dry, high-carbon fuels such as bituminous coals and coke. Sulfur content, which affects PC operation, has little effect on IGCC cost or efficiency, although it may impact the size of the sulfur clean-up process. For IGCC plants, coal ash consumes heat energy to melt it, requires more water per unit carbon in the slurry, increases the size of the ASU, and ultimately results in reduced overall efficiency. This is more problematic for slurry-feed gasifiers, and therefore, high-ash coals are more suited to dry-feed systems (Shell), fluid-bed gasifiers (BHEL), or moving-bed gasifiers (Lurgi) [25]. Slurry-fed gasifiers have similar problems with high-moisture coals and coal types with low heating values, such as lignite. These coal types decrease the energy density of the slurry, increase the oxygen demand, and decrease efficiency. Dry-feed gasifiers are favored for high-moisture content feeds.

Coal quality and heating value impact IGCC capital cost and generating efficiency more strongly than they affect these parameters for PC generation (see Figure A-3.A.3, Appendix 3.A) [25]. However, the lower cost of coals with low heating value can offset much of the impact of increased capital cost and reduced efficiency. To illustrate, the capital cost per kW, and the generating efficiency for an E-Gas IGCC plant designed for Texas lignite are estimated to be 37% higher and 24% lower respectively than if the unit were designed for Pittsburgh #8 coal [25]. For PC combustion the impact is significantly less: 24% higher and 10% lower respectively. As a result, we estimate that the COE for Texas lignite generation is about 20% higher (Figure A-3.A.4) than for Pittsburgh #8 coal because lower coal cost is not sufficient to offset the other increases.
Texas lignite has a high-moisture content and a low-carbon content, which is particularly bad for a slurry-feed gasifier. For a dry-feed gasifier, such as the Shell gasifier, the lignite would compare more favorably. Optimum gasifier type and configuration are influenced by coal type and quality, but there are limited data on these issues.

The available data illustrate several important trends and gaps. First, there is a lack of data and design studies for IGCC with low-heating value, low-quality coals and particularly for gasifiers other than water-slurry fed, entrained-flow systems. Second, PC generation without CO₂ capture is slightly favored over IGCC (lower COE) for high heating value, bituminous coals, but this gap increases as PC steam cycle efficiency increases and as coal heating value decreases. The COE gap is substantially widened (favoring PC) for coals with low heating values, such as lignite. Third, for CO₂ capture, the COE gap for high-heating value bituminous coals is reversed and is substantial (IGCC now being favored); but as coal heating value decreases, the COE gap is substantially narrowed. It appears that ultracritical PC combustion and lower energy consuming CO₂ capture technology, when developed, could have a lower COE than water-slurry fed IGCC with CO₂ capture. This area needs additional study.

**U.S. CRITERIA POLLUTANT IMPACTS – ENVIRONMENTAL PERFORMANCE**  IGCC has inherent advantages with respect to emissions control. The overall environmental footprint of IGCC is smaller than that of PC because of reduced volume and lower leachability of the fused slag, reduced water usage and the potential for significantly lower levels of criteria pollutant emissions. Criteria emissions control is easier because most clean-up occurs in the syngas which is contained at high pressure and has not been diluted by combustion air, i.e. nitrogen. Thus, removal can be more effective and economical than cleaning up large volumes of low-pressure flue gas.

The two operating IGCC units in the U.S. are meeting their permitted levels of emissions, which are similar to those of PC units. However, IGCC units that have been designed to do so can achieve almost order-of-magnitude lower criteria emissions levels than typical current U.S. permit levels and 95+% mercury removal with small cost increases. Appendix 3.D details the environmental performance demonstrated and expected.

Our point COE estimates suggest that although improvements in PC emissions control technology, including mercury control, will increase the COE from PC units, the levels of increased control needed to meet federal emissions levels for 2015 should not make the COE from a PC higher than that from an IGCC. We estimate that the increased emissions control to meet the U.S. 2015 regulations, including mercury, will increase the PC COE by about 0.22 ¢/kWe-h to 5.00 ¢/kWe-h and the COE for IGCC to 5.16 ¢/kWe-h (Appendix 3.D). This does not include the cost of emissions allowances or major, unanticipated regulatory or technological changes. Although the COE numbers for PC and IGCC are expected to approach one another, the cost of meeting criteria pollutant and mercury emissions regulations should not force a change in technology preference from PC to IGCC without CO₂ capture.

However, evaluation and comparison of generating technologies for future construction need to incorporate the effect of uncertainty in the key variables into the economic evaluation. This includes uncertainty in technology performance, including availability and ability to cycle, and cost, in regulatory changes, including timing and cost, and in energy costs and electricity demand/dispatch. Forward estimates for each variable are set, values, bounds and probabilities are established; and a Monte Carlo simulation is done producing a sensitivity analysis of how changes in the variables affect the economics for a given plant. This analysis shows that as permitted future pollutant emissions levels are reduced and the cost of emissions control increases, the NPV
cost gap between PC and IGCC will narrow; and at some point, increased emissions control can be expected to lead to IGCC having the lower NPV cost. This, of course, depends on when and the extent to which these changes occur and on how emissions control technology costs change with time and increasing reduction requirements. This type of analysis is used widely in evaluating the commercial economics of large capital projects, of which generation is a set, but is outside the scope of this report.

The same analysis applies to consideration of future CO₂ regulations. The introduction of a CO₂ tax at a future date (dependent on date of imposition, CO₂ tax rate, rate of increase, potential grandfathering and retrofit costs) will drive IGCC to be the lowest NPV cost alternative at some reasonable set of assumptions, and assuming today’s technology performance. Substantial technology innovation could change the outcome, as could changing the feed from bituminous coal to lignite.

In light of all these considerations, it is clear that there is no technology today that is an obvious silver bullet.

**RETROFITS FOR CO₂ CAPTURE** Retrofitting an IGCC for CO₂ capture involves changes in the core of the gasification/combustion/power generation train that are different than the type of changes involved in retrofitting a PC plant for capture. The choice of the gasifier (slurry feed, dry feed), gasifier configuration (full-quench, radiant cooling, convective syngas coolers), acid gas clean-up, operating pressure, and gas turbine are dependent on whether a no-capture or a capture plant is being built. Appendix 3.E treats IGCC retrofitting in more detail.

No-capture designs tend to favor lower pressure [2.8 to 4.1 MPa (400–600 psi)] and increased heat recovery from the gasifier train (radiant coolers and even syngas coolers) to raise more steam for the steam turbine, resulting in a higher net generating efficiency. Dry feed (Shell) provides the highest efficiency and is favored for coals with lower heating value, largely because of their higher moisture content; but the capital costs are higher. On the other hand, capture designs favor higher-pressure [6.0 MPa (1000 psi)] operation, slurry feed, and full-quench mode [59]. Full-quench mode is the most effective method of adding sufficient steam to the raw syngas for the water gas shift reaction without additional, expensive steam raising equipment and/or robbing steam from the steam cycle. Higher pressure reduces the cost of CO₂ capture and recovery, and of CO₂ compression. In addition, the design of a high-efficiency combustion turbine for high hydrogen concentration feeds is different from combustion turbines optimized for syngas, requires further development, and has very little operating experience. In summary, an optimum IGCC unit design for no CO₂ capture is quite different from an optimum unit design for CO₂ capture.

Although retrofitting an IGCC unit for capture would involve significant changes in most components of the unit if it is to result in an optimum CO₂-capture unit, it appears that an IGCC unit could be successfully retrofitted by addressing the key needed changes (adding shift reactors, an additional Selexol unit, and CO₂ compression/drying). In this case, retrofitting an IGCC unit would appear to be less expensive than retrofitting a PC unit, although it would not be an optimum CO₂-capture unit. Pre-investment for later retrofit will generally be unattractive and will be unlikely for a technology that is trying to establish a competitive position. However, for IGCC, additional space could be set aside to facilitate future retrofit potential. In addition, planning for a possible retrofit for capture could influence initial design choices (e.g., radiant quench vs. full quench).

**IGCC OPERATIONAL HISTORY** In addition to cost, IGCC has to overcome the perception of poor availability and operability. Appendix 3.B provides more detail, beyond that discussed below. For each of the current IGCC demonstration plants, 3 to 5 years was required to reach 70 to 80% availability after
commercial operation was initiated. Because of the complexity of the IGCC process, no single process unit or component of the total system is responsible for the majority of the unplanned shutdowns that these units have experienced, reducing IGCC unit availability. However, the gasification complex or block has been the largest factor in reducing IGCC availability and operability. Even after reaching 70 to 80% availability, operational performance has not typically exceeded 80% consistently. A detailed analysis of the operating history of the Polk Power Station over the last few years suggests that it is very similar to operating a petroleum refinery, requiring continuous attention to avert, solve and prevent mechanical, equipment and process problems that periodically arise. In this sense, the operation of an IGCC unit is significantly different from the operation of a PC unit, and requires a different operational philosophy and strategy.

The Eastman Chemical Coal Gasification Plant uses a Texaco full-quench gasifier and a backup gasifier (a spare) and has achieved less than 2% forced outage from the gasification/syngas system over almost 20 years operation. Spar- ing is one approach to achieving better on-line performance, and a vigorous equipment health maintenance and monitoring program is another. There are five operating in-refi nery IGCC units based on petroleum resid- uals and/or coke; two are over 500 MW\textsubscript{e} each. Several other refi nery-based gasification units produce steam, hydrogen, synthesis gas, and power. They have typically achieved better oper- ating performance, more quickly than the coal-based IGCC units. Three more are under construction. It is fair to say that IGCC is well established commercially in the refinery setting. IGCC can also be considered commercial in the coal-based electricity generation setting, but in this setting it is neither well established nor mature. As such, it is likely to undergo significant change as it matures.

Our analysis assumes that IGCC plants, with or without capture, can “cycle” to follow load requirements. However, there is relatively little experience with cycling of IGCC plants (although the 250 MW\textsubscript{e} Shell IGCC at Buggenum operated for 2 years in a load follow- ing mode under grid dispatch in the general range 50–100% load, and the Negishi IGCC unit routinely cycles between 100 to 75% load, both up and down, in 30 min) so considerable uncertainty exists for these performance features. Because an IGCC plant is “integrated” in its operation any shortfall in this performance could cause considerable increase in both variable and capital cost.

**COAL TO FUELS AND CHEMICALS**

Rather than burning the syngas produced by coal gasification in a combustion turbine, it can be converted to synthetic fuels and chemi- cals. The syngas is first cleaned of particulates and sulfur compounds and undergoes water gas shift to obtain the desired hydrogen to CO ratio. Fischer-Tropsch technology can be used to convert this syngas or “synthesis gas” into predominantly high-quality diesel fuel, along with naphtha and LPG. Fischer-Tropsch technology involves the catalytic conversion of the hydrogen and carbon monoxide in the synthesis gas into fuel range hydrocarbons. This technology has been used in South Africa since the 1950’s, and 195,000 barrels per day of liquid fuels are currently being produced in that country by Fischer-Tropsch. Synthesis gas can also be converted to methanol which can be used directly or be upgraded into high-octane gasoline. For gaseous fuels production, the synthesis gas can be converted into meth- ane, creating synthetic natural gas (SNG). Figure 3.15 illustrates three potential coal to fuels or chemicals process options. This type of process configuration could be called a coal refinery. More details are presented in Appendix 3.F.

Methanol production from coal-based syn- thesis gas is also a route into a broad range of chemicals. The naphtha and lighter hydrocarbons produced by Fischer-Tropsch are another route to produce a range of chemicals, in addition to the diesel fuel produced. The largest commodity chemical produced from
synthesis gas today is ammonia. Although most U.S. ammonia plants were designed to produce their syngas by reforming natural gas, worldwide there are a significant number of ammonia plants that use syngas from coal gasification and more are under construction. These routes to chemicals are easily integrated into a coal refinery, as is power generation. Commercially, these processes will be applied to the extent that they make economic sense and are in the business portfolio of the operating company.

For such a coal refinery, all the carbon entering in the coal exits as carbon in the fuels or chemicals produced, or as CO₂ in concentrated gas form that could easily be compressed for sequestration. In this case, of order 50% to 70% of the carbon in the coal would be in the form of CO₂ ready for sequestration. If the gasification product were hydrogen, then essentially all the carbon entering the refinery in the coal would appear in concentrated CO₂ streams that could be purified and compressed for sequestration. Without carbon capture and sequestration (CCS), we estimate that the Fischer-Tropsch fuels route produces about 150% more CO₂ as compared with the use of the petroleum-derived fuel products. For SNG, up to 175% more CO₂ is emitted than if regular natural gas is burned. With CCS, the full fuel-cycle CO₂ emissions for both liquid fuel and SNG are comparable with traditional production and utilization methods. Fortunately, CCS does not require major changes to the process, large amounts of additional capital, or significant energy penalties because the CO₂ is a relatively pure byproduct of the process at intermediate pressure. CCS requires drying and compressing to supercritical pressure. As a result of this the CO₂ avoided cost for CCS in conjunction with fuels and chemicals manufacture from coal is about one third of the CO₂ avoided cost for IGCC.

CITATIONS AND NOTES

3. Average generating efficiency of the U.S. coal fleet was determined from the EIA Electric Power Annual Review (2003) by dividing the total MWe-h of coal-based electricity generated by the coal consumed in generating that power. This efficiency has been invariant from 1992 to 2003. NETL (2002) gives coal fleet plant efficiency as a function of plant age.
4. In the U.S., the generating technology choice depends upon a number of issues, including: cost, criteria pollutant limits, coal type, efficiency, plant availability requirements, plant location (elevation and temperature) and potential for carbon dioxide regulations.
7. Other modeling tools could have been used. Each would have given somewhat different results because of the myriad of design and parameter choices, and engineering approximations included in each. Model results are consistent with other models when operational differences are accounted for (Appendix 3-B).
8. U.S. engineering practice is to use the higher heating value (HHV) of the fuel in calculating generating efficiency, and electrical generating efficiencies are expressed on an HHV basis. Fuel prices are also normally quoted on an HHV basis. The HHV of a fuel includes the heat recovered in condensing the water formed in combustion to liquid water. If the water is not condensed, less heat is recovered; and the value is the Lower Heating Value (LHV) of the fuel.

9. Of these variables, steam cycle severity (steam temperature and pressure) is the most important. Steam cycle severity increases from subcritical to supercritical to ultrasupercritical. Increasing severity means that the steam carries more available energy to the steam turbine, resulting in higher generating efficiency.


14. Tonne is used to refer to metric or long tonnes, which are 2200 pounds or 1000 kg, and Ton is used to refer to a short ton which is 2000 pounds. Although both are used in this report, we are consistent in distinguishing tonne and ton.

15. Changes in operating parameters, excluding emissions control levels, can shift the generating efficiency by upwards to one percentage point. Large changes in emissions control levels can have a similarly large effect. A conservative set of parameters was used in this study, giving a generating efficiency somewhat below the midpoint of the range. See Appendix 3-B and Appendix 3-D for more detail.

16. As steam pressure and temperature are increased above 218 atm (3200 psi) and 375° C (706° F), respectively, the water-steam system becomes supercritical. Under these conditions the two-phase mixture of liquid water and gaseous steam disappears. Instead with increasing temperature the fluid phase undergoes gradual transition from a single dense liquid-like phase to a less dense vapor-like phase, characterized by its own unique set of physical properties.

17. However, due to materials-related boiler tube fatigue and creep stress in headers, steamlines, and in the turbines, the utility industry moved back to subcritical technology for new U.S. coal power plants. Even after the materials problems were resolved there was not a move back to supercritical PC because at the very cheap price of U.S. coal, the added plant cost could not be justified on coal feed rate savings.


25. NCC, Opportunities to Expedite the Construction of New Coal-Based Power Plants. 2004, National Coal Council.


32. The options for CO2 capture include: (a) chemical absorption into solution, (b) physical adsorption with an adsorbent, (c) membrane separation from the gas, and (d) cryogenic separation, by distillation or freezing. Methods b through d are best suited to high concentrations of CO2, and or gas streams at high pressure, and not the low concentrations of CO2 in flue gas at one atmosphere total pressure.


35. These include EPRI reviews of electricity generating costs, National Coal Council concensus numbers, and generating equipment makers and utilities comments on published numbers.


46. NETL, NETL Coal Power Database, NETL, Editor. 2002, U.S. DOE.

47. Simbeck, D., Existing Power Plants - CO2 Mitigation Costs, Personal communication to J.R. Katzer, 2005: Cambridge, MA.


54. To estimate the COE for IGCC, without and with CO2 capture, we developed a consistent set of TPC numbers from the design studies and then compared these and our cost deltas with industry consensus group numbers to arrive at the TPC numbers given in Table 3.5. We estimated the O&M costs and calculated the COE using the parameters in Table 3.4. These are the COE numbers in Table 3.5.


Chapter 4 — Geological Carbon Sequestration

Carbon sequestration is the long term isolation of carbon dioxide from the atmosphere through physical, chemical, biological, or engineered processes. The largest potential reservoirs for storing carbon are the deep oceans and geological reservoirs in the earth’s upper crust. This chapter focuses on geological sequestration because it appears to be the most promising large-scale approach for the 2050 timeframe. It does not discuss ocean or terrestrial sequestration1,2.

In order to achieve substantial GHG reductions, geological storage needs to be deployed at a large scale.3,4 For example, 1 Gt C/yr (3.6 Gt CO₂/yr) abatement, requires carbon capture and storage (CCS) from 600 large pulverized coal plants (~1000 MW each) or 3600 injection projects at the scale of Statoil’s Sleipner project.5 At present, global carbon emissions from coal approximate 2.5 Gt C. However, given reasonable economic and demand growth projections in a business-as-usual context, global coal emissions could account for 9 Gt C (see table 2.7). These volumes highlight the need to develop rapidly an understanding of typical crustal response to such large projects, and the magnitude of the effort prompts certain concerns regarding implementation, efficiency, and risk of the enterprise.

The key questions of subsurface engineering and surface safety associated with carbon sequestration are:

**Subsurface issues:**
- Is there enough capacity to store CO₂ where needed?
- Do we understand storage mechanisms well enough?
- Could we establish a process to certify injection sites with our current level of understanding?
- Once injected, can we monitor and verify the movement of subsurface CO₂?

**Near surface issues:**
- How might the siting of new coal plants be influenced by the distribution of storage sites?
- What is the probability of CO₂ escaping from injection sites? What are the attendant risks? Can we detect leakage if it occurs?
- Will surface leakage negate or reduce the benefits of CCS?

Importantly, there do not appear to be unsolvable open technical issues underlying these questions. Of equal importance, the hurdles to answering these technical questions well appear manageable and surmountable. As such, it appears that geological carbon sequestration is likely to be safe, effective, and competitive with many other options on an economic basis. This chapter explains the technical basis for these statements, and makes recommendations about ways of achieving early resolution of these broad concerns.
SCIENTIFIC BASIS

A number of geological reservoirs appear to have the potential to store many 100’s – 1000’s of gigatons of CO₂.6 The most promising reservoirs are porous and permeable rock bodies, generally at depths, roughly 1 km, at pressures and temperatures where CO₂ would be in a supercritical phase.7

- **Saline formations** contain brine in their pore volumes, commonly of salinities greater than 10,000 ppm.
- **Depleted oil and gas fields** have some combination of water and hydrocarbons in their pore volumes. In some cases, economic gains can be achieved through enhanced oil recovery (EOR)8 or enhanced gas recovery9 and substantial CO₂-EOR already occurs in the US with both natural and anthropogenic CO₂.10
- **Deep coal seams**, often called unmineable coal seams, are composed of organic minerals with brines and gases in their pore and fracture volumes.
- Other potential geological target classes have been proposed and discussed (e.g., oil shales, flood basalts); however, these classes require substantial scientific inquiry and verification, and the storage mechanisms are less well tested and understood (see Appendix 4.A for a more detailed explanation).

Because of their large storage potential and broad distribution, it is likely that most geological sequestration will occur in saline formations. However, initial projects probably will occur in depleted oil and gas fields, accompanying EOR, due to the density and quality of subsurface data and the potential for economic return (e.g., Weyburn). Although there remains some economic potential for enhanced coal bed methane recovery, initial economic assessments do not appear promising, and substantial technical hurdles remain to obtaining those benefits.6

For the main reservoir classes, CO₂ storage mechanisms are reasonably well defined and understood (Figure 4.1). To begin, CO₂ sequestration targets will have physical barriers to CO₂ migration out of the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the reservoir target, although they may also be dynamic in the form of regional hydrodynamic flow. This storage mechanism allows for very high CO₂ pore volumes, in excess of 80%, and act immediately to limit CO₂ flow. At the pore scale, capillary forces will immobilize a substantial fraction of a CO₂ bubble, commonly measured to be between 5 and 25% of the pore volume. That CO₂ will be trapped as a residual phase in the pores, and acts over longer time scales as a CO₂ plume which is attenuated by flow. Once in the pore, over a period of tens to hundreds of years, the CO₂ will dissolve into other pore fluids, including hydrocarbon species (oil and gas) or brines, where the CO₂ is fixed indefinitely, unless other processes intervene. Over longer time scales (hundreds to thousands of years) the dissolved CO₂ may react with minerals in the rock volume to precipitate the CO₂ as new carbonate minerals. Finally, in the case of organic mineral frameworks such as coals, the CO₂ will physically adsorb onto the rock surface, sometimes displacing other gases (e.g., methane, nitrogen).

Although substantial work remains to characterize and quantify these mechanisms, they are understood well enough today to trust estimates of the percentage of CO₂ stored over some period of time—the result of decades of studies in analogous hydrocarbon systems, natural gas storage operations, and CO₂-EOR. Specifically, it is very likely that the fraction of stored CO₂ will be greater than 99% over 100 years, and likely that the fraction of stored CO₂ will exceed 99% for 1000 years6. Moreover, some mechanisms appear to be self-reinforcing.11,12 Additional work will reduce the uncertainties associated with long-term efficacy and numerical estimates of storage volume capacity, but no knowledge gaps today appear to cast doubt on the fundamental likelihood of the feasibility of CCS.
While improvement in understanding of storage mechanisms would help to improve capacity estimates, the fundamental limit to high quality storage estimates is uncertainty in the pore volumes themselves. Most efforts to quantify capacity either regionally or globally are based on vastly simplifying assumptions about the overall rock volume in a sedimentary basin or set of basins. Such estimates, sometimes called “top-down” estimates, are inherently limited since they lack information about local injectivity, total pore volumes at a given depth, concentration of resource (e.g., stacked injection zones), risk elements, or economic characteristics.

A few notable exceptions to those kinds of estimates involve systematic consideration of individual formations and their pore structure within a single basin. The most comprehensive of this kind of analysis, sometimes called “bottom-up”, was the GEODISC effort in Australia. This produced total rock volume estimates, risked volume estimates, pore-volume calculations linked to formations and basins, injectivity analyses, and economic qualifications on the likely injected volumes. This effort took over three years and $10 million Aus. Institutions like the US Geological Survey or Geoscience Australia are well equipped to compile and integrate the data necessary for such a capacity determination, and would be able to execute such a task rapidly and well.

Our conclusions are similar to those drawn by the Carbon Sequestration Leadership Forum (CSLF), which established a task force to examine capacity issues. They recognized nearly two-orders of magnitude in uncertainty within individual estimates and more than two orders magnitude variance between estimates (Figure 4.2). The majority of estimates support the contention that sufficient capacity exists to store many 100’s to many 1000’s of gigatons CO₂, but this uncertain range is too large to inform sensible policy.

**Figure 4.1 Schematic of Sequestration Trapping Mechanisms**

Schematic diagram of large injection at 10 years time illustrating the main storage mechanisms. All CO₂ plumes are trapped beneath impermeable shales (not shown). The upper unit is heterogeneous with a low net percent usable; the lower unit is homogeneous. Central insets show CO₂ as a mobile phase (lower) and as a trapped residual phase (upper). Right insets show CO₂ dissolution (upper) and CO₂ mineralization (lower).
Accordingly, an early priority should be to undertake “bottom-up” capacity assessments for the US and other nations. Such an effort requires detailed information on individual rock formations, including unit thickness and extent, lithology, seal quality, net available percentage, depth to water table, porosity, and permeability. The geological character and context matters greatly and requires some expert opinion and adjudication. While the data handling issues are substantial, the costs would be likely to be low ($10-50 million for a given continent; $100 million for the world) and would be highly likely to provide direct benefits in terms of resource management.18 Perhaps more importantly, they would reduce substantially the uncertainty around economic and policy decisions regarding the deployment of resource and crafting of regulation.

Within the US, there is an important institutional hurdle to these kinds of capacity estimates. The best organization to undertake this effort would be the US Geological Survey, ideally in collaboration with industry, state geological surveys, and other organizations. This arrangement would be comparable in structure and scope to national oil and gas assessments, for which the USGS is currently tasked. This is analogous to performing a bottom-up CO₂ storage capacity estimation. However, the USGS has no mandate or resources to do CO₂ sequestration capacity assessments at this time.

The Department of Energy has begun assessment work through the seven Regional Carbon Sequestration Partnerships19. These partnerships include the member organizations of 40 states, including some state geological surveys. While the Partnerships have produced and will continue to produce some detailed formation characterizations, coverage is not uniform and the necessary geological information not always complete. As such, a high-level nationwide program dedicated to
bottom-up geological assessment would best serve the full range of stakeholders interested in site selection and management of sequestration, as do national oil and gas assessments.

**SITE SELECTION AND CERTIFICATION CRITERIA**

Capacity estimates, in particular formation-specific, local capacity assessments, will underlie screening and site selection and help define selection criteria. It is likely that for each class of storage reservoir, new data will be required to demonstrate the injectivity, capacity, and effectiveness (ICE) of a given site. A firm characterization of ICE is needed to address questions regarding project lifecycle, ability to certify and later close a site, site leakage risks, and economic and liability concerns.

Ideally, project site selection and certification for injection would involve detailed characterization given the geological variation in the shallow crust. In most cases, this will require new geological and geophysical data sets. The specifics will vary as a function of site, target class, and richness of local data. For example, a depleted oil field is likely to have well, core, production, and perhaps seismic data that could be used to characterize ICE rapidly. Still additional data (e.g., well-bore integrity analysis, capillary entry pressure data) may be required. In contrast, a saline formation project may have limited well data and lack core or seismic data altogether. Geological characterization of such a site may require new data to help constrain subsurface uncertainty. Finally, while injectivity may be readily tested for CO₂ storage in an unmineable coal seam, it may be extremely difficult to establish capacity and storage effectiveness based on local stratigraphy. Accordingly, the threshold for validation will vary from class to class and site to site, and the due diligence necessary to select a site and certify it could vary greatly.

**OPEN ISSUES** The specific concerns for each class of storage are quite different. For depleted hydrocarbon fields, the issues involve incremental costs necessary to ensure well or field integrity. For saline formations, key issues will involve appropriate mapping of potential permeability fast-paths out of the reservoir, accurate rendering of subsurface heterogeneity and uncertainty, and appropriate geomechanical characterization. For unmineable coal seams, the issues are more substantial: demonstration of understanding of cleat structure and geochemical response, accurate rendering of sealing architecture and leakage risk, and understanding transmissivity between fracture and matrix pore networks. For these reasons, the regulatory framework will need to be tailored to classes of sites.

**MEASUREMENT, MONITORING, AND VERIFICATION: MMV**

Once injection begins, a program for measurement, monitoring, and verification (MMV) of CO₂ distribution is required in order to:

- understand key features, effects, & processes needed for risk assessment
- manage the injection process
- delineate and identify leakage risk and surface escape
- provide early warnings of failure near the reservoir
- verify storage for accounting and crediting

For these reasons, MMV is a chief focus of many research efforts. The US Department of Energy has defined MMV technology development, testing, and deployment as a key element to their technology roadmap, and one new EU program (CO₂ ReMoVe) has allocated €20 million for monitoring and verification. The IEA has established an MMV working group aimed at technology transfer between large projects and new technology developments. Because research and demonstration projects are attempting to establish the scientific basis for geological sequestration, they will require more involved MMV systems than future commercial projects.
Today there are three well-established large-scale injection projects with an ambitious scientific program that includes MMV: Sleipner (Norway)\(^2\), Weyburn (Canada)\(^3\), and In Salah (Algeria)\(^4\). Sleipner began injection of about 1 Mt CO\(_2\)/yr into the Utsira Formation in 1996. This was accompanied by time-lapse reflection seismic volume interpretation (often called 4D-seismic) and the SACS scientific effort. Weyburn is an enhanced oil recovery effort in South Saskatchewan that served as the basis for a four-year, $24 million international research effort. Injection has continued since 2000 at about 0.85 Mt CO\(_2\)/yr into the Midale reservoir. A new research effort has been announced as the Weyburn Final Phase, with an anticipated budget comparable to the first. The In Salah project takes about 1 Mt CO\(_2\)/yr stripped from the Kretchba natural gas field and injects it into the water leg of the field. None of these projects has detected CO\(_2\) leakage of any kind, each appears to have ample injectivity and capacity for project success, operations have been transparent and the results largely open to the public.

Over the next decade, several new projects at the Mt/yr scale may come online from the myriad of projects announced (see Table 4.1). These will provide opportunities for further scientific study.

Perhaps surprisingly in the context of these and other research efforts, there has been little discussion of what are the most important parameters to measure and in what context (research/pilot vs. commercial). Rather, the literature has focused on the current ensemble of tools and their costs.\(^5\) In part due to the success at Sleipner, 4-D seismic has emerged as the standard for comparison, with 4-D surveys deployed at Weyburn and likely to be deployed at In Salah. This technology excels at delineating the boundaries of a free-phase CO\(_2\) plume, and can detect small saturations of conjoined free-phase bubbles that might be an indicator of leakage. Results from these 4D-seismic surveys are part of the grounds for belief in the long-term effectiveness of geological sequestration.

However, time-lapse seismic does not measure all the relevant parameters, and has limits in some geological settings. Key parameters for research and validation of CO\(_2\) behavior and fate involve both direct detection of CO\(_2\) and detection through proxy data sets (figure 4.3). Table 4.2 provides a set of key parameters, the current best apparent measurement and monitoring technology, other potential tools, and the status of deployment in the world’s three largest injection demonstrations

Importantly, even in the fields where multiple monitoring techniques have been deployed (e.g., Weyburn), there has been little attempt to integrate the results (this was identified as a research gap from the Weyburn effort).\(^3\) There are precious few formal methods to integrate and jointly invert multiple data streams. This is noteworthy; past analyses have demonstrated that formal integration of orthogonal data often provides robust and strong interpretations of subsurface conditions and characteristics.\(^6\) The absence of integration of measurements represents a major gap in current MMV capabilities and understanding.

| Table 4.1 Proposed CCS Projects at the Mt/yr scale |
|---------------------------------|-----------------|-----------------|
| PROJECT                        | COUNTRY         | PROJECT TYPE    |
| Monash                         | Australia       | Fuel            |
| ZeroGen                        | Australia       | Power           |
| Gorgon                         | Australia       | Gas Processing  |
| SaskPower                      | Canada          | Power           |
| Greengen                       | China           | Power           |
| nZEC                           | China           | Power           |
| Vattenfall                     | Germany         | Power           |
| RWE                            | Germany         | Power           |
| Draugen                        | Norway          | Power           |
| Statoil Mongstad               | Norway          | Power           |
| Snovit                         | Norway          | Gas Processing  |
| BP Peterhead                   | UK              | Power           |
| E.On                           | UK              | Power           |
| RWE npower                     | UK              | Power (retrofitted) |
| Progressive/Centrica           | UK              | Power           |
| Powerfuel                      | UK              | Power           |
| FutureGen                      | USA             | Power           |
| BP Carson                      | USA             | Power           |

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In addition to development, testing, and integration of MMV technology, there is no standard accepted approach (e.g., best practices) to the operation of MMV networks. This is particularly important in future commercial projects, where a very small MMV suite focused on leak detection may suffice. To be effective, it is likely that MMV networks must cover the footprint of injection at a minimum, and include sampling near the reservoir and at the surface. Within the context of a large-scale deployment, it is likely that determination and execution of monitoring will involve a four-phase approach.

1. **Assessment and planning:** During this phase, the site is characterized geographically, geologically, geophysically, and geochemically. Forward simulation of monitoring approaches will help to predict the detection thresholds of a particular approach or tool. Based on this analysis, an array can be designed to meet the requirements of regulators and other stakeholders.

2. **Baseline monitoring:** Before injection takes place, baseline surveys must be collected to understand the background and provide a basis for difference mapping.

3. **Operational monitoring:** During injection, injection wells are monitored to look for circulation behind casing, failures within the wellbore, and other operational problems or failures.

4. **Array monitoring during and after injection:** This phase will involve active surface and subsurface arrays, with the potential for additional tools around high-risk zones. The recurrence and total duration of monitoring will be determined by the research goals, the site parameters, the commercial status and regulatory needs. Ideally, MMV data would be formally integrated to reduce operational cost and complexity and to provide higher fidelity.

The likely duration of monitoring is an important unresolved issue. It is impractical for monitoring to continue for hundreds of years after injection; a practical monitoring time...
period should be defined either generally or at each site before injection begins. Substantial uncertainties remain regarding the detection thresholds of various tools, since the detection limit often involves assumptions about the distribution, continuity, and phase of subsurface CO2. Important issues remain about how to optimize or configure an array to be both effective and robust. This issue cannot be answered without testing and research at large-scale projects and without formal data integration.

**LEAKAGE RISKS**

Since CO2 is buoyant in most geological settings, it will seek the earth’s surface. Therefore, despite the fact that the crust is generally well configured to store CO2, there is the possibility of leakage from storage sites. Leakage of CO2 would negate some of the benefits of sequestration. If the leak is into a contained environment, CO2 may accumulate in high enough concentrations to cause adverse health, safety, and environmental consequences. For any subsurface injected fluid, there is also the concern for the safety of drinking water. Based on analogous experience in CO2 injection such as acid gas disposal and EOR, these risks appear small. However, the state of science today cannot provide quantitative estimates of their likelihood.

Importantly, CO2 leakage risk is not uniform and it is believed that most CO2 storage sites will work as planned. However, a small percentage of sites might have significant leakage rates, which may require substantial mitigation efforts or even abandonment. It is important to note that the occurrence of such sites does not negate the value of the effective sites. However, a premium must be paid in the form of due diligence in assessment to quantify and circumscribe these risks well.

Wells almost certainly present the greatest risk to leakage, because they are drilled to bring large volumes of fluid quickly to the earth’s surface. In addition, they remove the aspects of the rock volume that prevent buoyant migration. Well casing and cements are susceptible to corrosion from carbonic acid. When wells are adequately plugged and completed, they trap CO2 at depth effectively. However, there are large numbers of orphaned or abandoned wells that may not be adequately plugged, completed, or cemented (Chapter 4 Appendix B) and such wells represent potential leak points for CO2. Little is known about the specific probability of escape from a given well, the likelihood of such a well existing within a potential site, or the risk such a well presents in terms of potential leakage volume or consequence. While analog situations provide some quantitative estimates (e.g., Crystal Geyser, UT), much remains to
be done to address these questions. Once a well is identified, it can be plugged or re-completed at fairly low cost.

There is the possibility of difficult to forecast events of greater potential damage. While these events are not analogous for CO₂ sequestration, events like the degassing of volcanic CO₂ from Lake Nyos or the natural gas storage failure near Hutchinson, Kansas speak to the difficulty of predicting unlikely events. However, while plausible, the likelihood of leaks from CO₂ sequestration causing such damage is exceedingly small (i.e., the rate of any leakage will be many orders of magnitude less than Lake Nyos and CO₂ is not explosive like natural gas).

Even though most potential leaks will have no impact on health, safety, or the local environment, any leak will negate some of the benefits of sequestration. However, absolute containment is not necessary for effective mitigation. If the rate and volume of leakage are sufficiently low, the site will still meet its primary goal of sequestering CO₂ to reduce atmospheric warming and ocean acidification. The leak would need to be counted as an emissions source as discussed further under liability. Small leakage risks should not present a barrier to deployment or reason to postpone an accelerated field-based RD&D program. This is particularly true of early projects, which will also provide substantial benefits of learning by doing and will provide insight into management and remediation of minor leaks.

A proper risk assessment would focus on several key elements, including both likelihood and potential impact. Efforts to quantify risks should focus on scenarios with the greatest potential economic or health and safety consequences. An aggressive risk assessment research program would help financiers, regulators, and policy makers decide how to account accurately for leakage risk.

**SCIENCE & TECHNOLOGY GAPS**

A research program is needed to address the most important science and technology gaps related to storage. The program should address three key concerns: (1) tools to simulate the injection and fate of CO₂; (2) approaches to predict and quantify the geomechanical response to injection; and (3) the ability to generate robust, empirically based probability-density functions to accurately quantify risks.

Currently, there are many codes, applications, and platforms to simulate CO₂ injection. However, these codes have substantial limitations. First, they do not predict well the geomechanical response of injection, including fracture dilation, fault reactivation, cap-rock integrity, or reservoir dilation. Second, many codes that handle reactive transport, do not adequately predict the location of precipitation or dissolution, nor the effects on permeability. Third, the codes lack good modules to handle wells, specifically including the structure, reactivity, or geomechanical response of wells. Fourth, the codes do not predict the risk of induced seismicity. In order to simulate key coupled processes, future simulators will require sizeable computational resources to render large complex sedimentary networks, and run from the injection reservoir to the surface with high resolution in three dimensions. Given the capability of existing industry and research codes, it is possible to advance coupling and computation capabilities and apply them to the resolution of outstanding questions.

There is also a need to improve geomechanical predictive capability. This is an area where many analog data sets may not provide much insight; the concerns focus on rapid injection of large volumes into moderate-low permeability rock, and specific pressure and rate variations may separate reservoirs that fail mechanically from those that do not. This is particularly true for large-volume, high-rate injections that have a higher chance of exceeding important process thresholds. Fault response to stress, prediction of induced seis-
micity, fault transmissivity and hydrology, and fracture formation and propagation are notoriously difficult geophysical problems due to the complex geometries and non-linear responses of many relevant geological systems. Even with an improved understanding, the models that render fracture networks and predict their geomechanical response today are fairly simple, and it is not clear that they can accurately simulate crustal response to injection. A program that focuses on theoretical, empirical, laboratory, and numerical approaches is vital and should take advantage of existing programs within the DOE, DOD, and NSF.

The objective of these research efforts is to improve risk-assessment capabilities that results in the construction of reliable probability-density functions (PDFs). Since the number of CO₂ injection cases that are well studied (including field efforts) are exceedingly small, there is neither theoretical nor empirical basis to calculate CO₂-risk PDFs. Accurate PDFs for formal risk assessment could inform decision makers and investors regarding the potential economic risks or operational liabilities of a particular sequestration project.

In terms of risk, leakage from wells remains the likeliest and largest potential risk.³⁴,⁴¹,⁴² The key technical, regulatory, and legal concerns surrounding well-bore leakage of CO₂ are discussed in Appendix 4.B.

NEED FOR STUDIES AT SCALE

Ultimately, large-scale injection facilities will be required to substantially reduce GHG emissions by CCS. Because the earth’s crust is a complex, heterogeneous, non-linear system, field-based demonstrations are required to understand the likely range of crustal responses, including those that might allow CO₂ to escape from reservoirs. In the context of large-scale experiments, the three large volume projects currently operating do not address all relevant questions. Despite a substantial scientific effort, many parameters which would need to be measured to circumscribe the most compelling scientific questions have not yet been collected (see Table 4.2), including distribution of CO₂ saturation, stress changes, and well-bore leakage detection. This gap could be addressed by expanded scientific programs at large-scale sites, in particular at new sites.

The projects sponsored by the DOE are mostly small pilot projects with total injection volume between 1000 and 10,000 metric tons. For example, the DOE sponsored a field injection in South Liberty, TX, commonly referred to as the Frio Brine Pilot.⁴³,⁴⁴ The Pilot received ~1800 t of CO₂ in 2004, and is slated to receive a second injection volume of comparable size in 2006. The Regional Partnerships have proposed 25 geological storage pilots of comparable size, which will inject CO₂ into a wide array of representative formations.¹⁹ These kinds of experiments provide value in validating some model predictions, gaining experience in monitoring, and building confidence in sequestration. However, pilots on this scale cannot be expected to address the central concerns regarding CO₂ storage because on this scale the injection transients are too small to reach key thresholds within the crust. As such, important non-linear responses that may depend on a certain pressure, pH, or volume displacement are not reached. However, they will be reached for large projects, and have been in each major test.

As an example, it has been known for many years that fluid injections into low-permeability systems can induce earthquakes small and large.⁴⁵ It is also known that while injection of fluids into permeable systems can induce earthquakes, even with large injection volumes the risk of large earthquakes is extremely low. The best example is a set of field tests conducted at Rangely oilfield in NW Colorado, where an aggressive water-injection program began in an attempt to initiate and control seismic events.⁴⁶ Despite large injections, the greatest moment magnitude measured as Mₛ 3.1. Since that time, over 28 million tons of CO₂ have been injected into Rangely with limited seismicity, no large seismic events,
and no demonstrable leakage. These studies make clear that injections of much smaller volumes would produce no seismicity. Thus to ascertain the risk associated with large injections requires large injection, as do the processes and effects of reservoir heterogeneity on plume distribution or the response of fractures to pressure transients.

**LARGE SCALE DEMONSTRATIONS AS CENTRAL SHORT-TERM OBJECTIVE**

Ultimately, large-scale injections will require large volumes of CO₂ to ensure that injection transients approach or exceed key geological thresholds. The definition of large-scale depends on the site since local parameters vary greatly. In highly permeable, continuous rock bodies (e.g., Frio Fm. or Utsira Fm.), at least one million tons/yr may be required to reach these thresholds; in low permeability (e.g., Weber Sandstone or Rose Run Fm.) or highly segmented reservoirs, only a few 100,000 tons/year may be required. A large project would likely involve multiple wells and substantial geological complexity and reservoir heterogeneity (like In Salah and Weyburn). To observe these effects would likely require at least 5 years of injection with longer durations preferred.

Because of the financial incentives of additional production, CO₂-EOR will continue to provide early opportunities to study large-scale injection (e.g., Weyburn). However, the overwhelming majority of storage capacity remains in saline formations, and there are many parts of the country and the world where EOR options are limited. Since saline formations will be central to substantial CO₂ emissions reduction, a technical program focused on understanding the key technical concerns of saline formations will be central to successful commercial deployment of CCS.

**Costs for the large projects are substantial.**

For phase I, the Weyburn project spent $27 million, but did not include the costs of CO₂ or well drilling in those costs. Because of cost constraints, the Weyburn project did not include important monitoring and scientific studies. The cost of CO₂ supply could be low if one assumes that the CO₂ supply were already concentrated (e.g., a fertilizer or gas processing stream) and compression would be the largest operating cost. If CO₂ required market purchase (e.g., from KinderMorgan pipelines into the Permian Basin), then a price of $20/ton CO₂ would represent a likely upper cost limit. Total cost would include compression costs, well count, reworking requirements, availability of key data sets, and monitoring complement. Based on these types of consideration, an eight-year project could achieve key technical and operational goals and deliver important new knowledge for a total cost between $100–225 million, corresponding to an annual cost roughly between $13–28 million. A full statement of the assumption set and calculation is presented in Appendix 4.C.

In sum, a large well-instrumented sequestration project at the necessary scale is required to yield the important information. However, only a small number of projects are likely to be required to deliver the needed insights for the most important set of geological injection conditions. For example, in the US only 3–4 sites might be needed to demonstrate and parameterize safe injection. These sites could include one project in the Gulf Coast, one in the central or northern Rocky Mountains, and one in either the Appalachian or Illinois basins (one could consider adding a fourth project in California, the Williston, or the Anadarko basins). This suite would cover an important range of population densities, geological and geophysical conditions, and industrial settings (Figure 4.4). More importantly, these 3–4 locations and their attendant plays are associated with large-scale current and planned coal-fired generation, making their parameterization, learning, and ultimate success important.

The value of information derived from these studies relative to their cost would be enormous. Using a middle cost estimate, all three
basins could be studied for $500 million over eight years. Five large tests could be planned and executed for less than $1 billion, and address the chief concerns for roughly 70% of potential US capacity. Information from these projects would validate the commercial scalability of geological carbon storage and provide a basis for regulatory, legal, and financial decisions needed to ensure safe, reliable, economic sequestration.

The requirements for sequestration pilot studies elsewhere in the world are similar. The number of projects needed to cover the range of important geological conditions around the world to verify the storage capacity is of order 10. Using the screening and selection parameters described in Appendix 4.C, we believe that the world could be tested for approximately a few billion dollars. The case for OECD countries to help developing nations test their most important storage sites is strong; the mechanisms remain unresolved and are likely to vary case to case.

DEVELOPING COUNTRIES

Developing nations, particularly China and India, will grow rapidly in the coming decades with an accompanying rapid growth in energy demand. Both countries have enormous coal reserves, and have plans to greatly increase national electrification with coal power. Projections for CO₂ emissions in both countries grow as a consequence, with the possibility that China will become the world’s largest CO₂ emitter by 2030. Therefore it is important to know what sequestration options exist for both nations.

China

The geological history of China is immensely complicated.

Draft suggestions for 4 large UC storage projects using anthropogenic CO₂ sources. Basemap of sequestration targets from Dooley et al., 2004.
shore and two offshore basins with relatively simple geological histories lie in the eastern half of China, close to coal sources, industrial centers, and high population densities. These are also the basins containing the largest oilfields and gas fields in China. Preliminary assessment suggests that these basins have prospectivity. The initial estimates are based on injectivity targets of 100 mD, and continued assessment will change the prospectivity of these basins.

There are a number of active sequestration projects in China. RIPED, CNPC, and other industrial and government entities are pursuing programs in CO2-EOR. These are driven by economic and energy security concerns; continued study will reveal the potential for storage in these and other fields. Some western companies are also pursuing low-cost CO2 projects; Shell is investigating a large CO2 pilot, and Dow has announced plans to sequester CO2 at one of its chemical plants. There is a 192 tonne Canadian-Chinese ECBM project in the Quinshui basin. However, there is much greater potential for very large CO2 storage tests using low-cost sources. China has many large coal gasification plants, largely for industrial purposes (e.g., fertilizer production, chemical plants). A number of these plants vent pure streams well in excess of 500,000 tons/y, and many are located within 150 km of viable geological storage and EOR targets.53

A program to determine the viability of large-scale sequestration in China would be first anchored in a detailed bottom-up assessment. The data for assessments exists in research institutions (e.g., RIPED, the Institute of Geology and Geophysics) and the long history of geological study and infrastructure suggests that Chinese teams could execute a successful assessment in a relatively short time, which could be followed by large injection tests. Given the central role of China’s emissions and economy in the near future and the complexity of its geology, this should involve no less than two large projects. One might target a high-value, high chance of success opportunity (e.g., Bohainan basis; Songliao). Another might target lower permeability, more complicated targets (e.g., Sichuan or Ji-
In all cases, large projects do not need to wait for the development of IGCC plants, since there is already enormous gasification capacity and large pure CO$_2$ streams near viable targets. As with any large target, a ranking of prospects and detailed geological site characterization would be key to creating a high chance of project success.

India

Geologically, India is a large granitic and metamorphic massif surrounded by sedimentary basins. These basins vary in age, complexity, and size. The largest sedimentary basin in the world (the Ganga basin) and one of the largest sedimentary accumulations (the Bengal fan) in India are close to many large point sources. In addition, a large basaltic massif (the Deccan Traps) both represents a potential CO$_2$ sink and also overlies a potential CO$_2$ sink (the underlying basins).

Currently, there is one CO$_2$ storage pilot planned to inject a small CO$_2$ volume into basalts. There are currently no plans for a detailed assessment or large-scale injection program. However, the IEA has announced a program to conduct an assessment. Many governmental groups have relevant data, including the Directorate General for Hydrocarbons, the Geological Survey of India, and the National Geophysical Research Institute. Several companies appear well equipped to undertake such work, including the Oil and Natural Gas Company of India. Despite the Indian government’s involvement in the CSLF and FutureGen, it has not yet made the study of carbon sequestration opportunities a priority.

CURRENT REGULATORY STATUS

At present, there is no institutional framework to govern geological sequestration of CO$_2$ at large scale for a very long period of time. At a minimum, the regulatory regime needs to cover the injection of CO$_2$, accounting and crediting as part of a climate regime, and site closure and monitoring. In the United States, there does exist regulations for underground injections (see discussion below), but there is no category specific to CO$_2$ sequestration. A regulatory capacity must be built, whether from the existing EPA underground injection program or from somewhere else. Building a regulatory framework for CCS should be considered a high priority item. The lack of a framework makes it more difficult and costly to initiate large-scale projects and will result in delaying large-scale deployment.

In the United States, there is a body of federal and state law that governs underground injection to protect underground sources of drinking water. Under authority from the Safe Drinking Water Act, EPA created the Underground Injection Control (UIC) Program, requiring all underground injections to be authorized by permit or rule and prohibiting certain types of injection that may present an imminent and substantial danger to public health. Five classes of injection wells have been set forth in the regulations, none specific to geological sequestration. A state is allowed to assume primary responsibility (“primacy”) for the implementation and enforcement of its underground injection control program if the state program meets the requirements of EPA’s UIC regulations. As shown in Figure 4.6, thirty-three states have full primacy over underground injection in their state, seven states share responsibility with EPA, and ten states have no primacy. A state program may go beyond the minimum EPA standards; in Nevada, for example, injection is not allowed into any underground aquifer regardless of salinity, which negates a potential sequestration option (Nevada Bureau of Mines and Geology, 2005).

The UIC achieves its primary objective of preventing movement of contaminants into potential sources of drinking water due to injection activities, by monitoring contaminant concentration in underground sources of drinking water. If traces of contaminants
are detected, the injection operation must be altered to prevent further pollution.

There are no federal requirements under the UIC Program to track the migration of injected fluids within the injection zone or to the surface. Lack of fluid migration monitoring is problematic when the UIC regulatory regime is applied to geological sequestration. For example, one source of risk for carbon sequestration is that injected CO$_2$ potentially leaks to the surface through old oil and gas wells. For various reasons, such as existing infrastructure and proved cap rock, the first geological sequestration projects in the US will likely take place at depleted oil and gas fields. These sites possess numerous wells, some of which can act as high permeability conduits to the surface. Plugs in these wells may be lacking, poor, or subject to corrosion from CO$_2$ dissolved in brine. The presence of wells at sequestration sites greatly increases the chance for escape of injected gas. Regulations will be needed for the particular circumstance of CO$_2$ storage. This will involve either modification of the UIC regulations or creation of a new framework.

Unlike onshore geological sequestration, which is governed by national law, offshore geological sequestration is governed by international law. Offshore sequestration has not been specifically addressed in any multilateral environmental agreements that are currently in force, but may fall under the jurisdiction of international and regional marine agreements, such as the 1972 London Convention, the 1996 Protocol to the London Convention, and the 1992 OSPAR Convention. Because these agreements were not designed with geological sequestration in mind, they may require interpretation, clarification, or amendment by their members. Most legal scholars agree that there are methods of offshore sequestration currently compatible with international law, including using a land-based pipeline transporting CO$_2$ to the sub-seabed injection point and injecting CO$_2$ in conjunction with offshore hydrocarbon activities.

LIABILITY

Liability of CO$_2$ capture and geological sequestration can be classified into operational liability and post-injection liability.
Operational liability, which includes the environmental, health, and safety risks associated with carbon dioxide capture, transport, and injection, can be managed within the framework that has been successfully used for decades by the oil and gas industries.

Post-injection liability, or the liability related to sequestered carbon dioxide after it has been injected into a geologic formation, presents unique challenges due to the expected scale and timeframe for sequestration. The most likely sources of post-injection liability are groundwater contamination due to subsurface migration of carbon dioxide, emissions of carbon dioxide from the storage reservoir to the atmosphere (i.e., non-performance), risks to human health, damage to the environment, and contamination of mineral reserves. Our understanding of these risks needs to be improved in order to better assess the liability exposure of operators engaging in sequestration activities.

In addition, a regulatory and liability framework needs to be adopted for the closing of geological sequestration injection sites. The first component of this framework is monitoring and verification. Sequestration operations should be conducted in conjunction with modeling tools for the post-injection flow of carbon dioxide. If monitoring validates the model, a limited monitoring and verification period (5-10 years) after injection operations may be all that is required, with additional monitoring and verification for exceptional cases. The second component of the framework defines the roles and financial responsibilities of industry and government after abandonment. A combination of a funded insurance mechanism with government back-stop for very long-term or catastrophic liability will be required. Financial mechanisms need to be considered to cover this responsibility. There are a number of ways in which the framework could proceed. For example, in the case of nuclear power, the Price-Anderson Act requires that nuclear power plant licensees purchase the maximum amount of commercial liability insurance available on the private market and participate in a joint-insurance pool. Licensees are not financially responsible for the cost of any accident exceeding these two layers of insurance. Another example would be the creation of a fund with mandatory contributions by injection operators. We suggest that industry take financial responsibility for liability in the near-term, i.e. through injection phase and perhaps 10-20 years into the post-injection phase. Once certain validation criteria are met, government would then assume financial responsibility, funded by industry insurance mechanisms, and perhaps funded by set-asides of carbon credits equal to a percentage of the amount of CO2 stored in the geological formation.

SEQUESTRATION COSTS

Figure 4.7 shows a map of US coal plants overlayed with potential sequestration reservoirs. The majority of coal-fired power plants are situated in regions where there are high expectations of having CO2 sequestration sites nearby. In these cases, the cost of transport and injection of CO2 should be less than 20% of total cost for capture, compression, transport, and injection.

Transportation for commercial projects will be via pipeline, with cost being a function of the distance and quantity transported. As shown in Figure 4.8, transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10 Mt CO2/yr. While Figure 4.8 shows typical values, costs can be highly variable from project to project due to both physical (e.g., terrain pipeline must traverse) and political considerations. For a 1 GWe coal-fired power plant, a pipeline must carry about 6.2 Gt CO2/yr (see footnote 1). This would result in a pipe diameter of about 16 inches and a transport cost of about $1/tCO2/100 km. Transport costs can be lowered through the development of pipeline networks as opposed to dedicated pipes between a given source and sink.
Costs for injecting the CO₂ into geologic formations will vary on the formation type and its properties. For example, costs increase as reservoir depth increases and reservoir injectivity decreases (lower injectivity results in the drilling of more wells for a given rate of CO₂ injection). A range of injection costs has been reported as $0.5-8/tCO₂. Costs will also vary with the distance transported, the capacity utilization of the pipe, the transport pressure and the costs of compression (which also produces CO₂).

It is anticipated that the first CCS projects will involve plants that are very close to a sequestration site or an existing CO₂ pipeline. As the number of projects grow, regional pipeline networks will evolve. This is similar to the growth of existing regional CO₂ pipeline networks in west Texas and in Wyoming to deliver CO₂ to the oil fields for EOR. For example, Figure 4.7 suggests that a regional pipeline network may develop around the Ohio River valley, transporting much larger volumes of CO₂.

**RECOMMENDATIONS**

Our overall judgment is that the prospect for geological CO₂ sequestration is excellent. We base this judgment on 30 years of injection experience and the ability of the earth’s crust to trap CO₂. That said, there remain substantial open issues about large-scale deployment of carbon sequestration. Our recommendations aim to address the largest and most important of these issues. Our recommendations call for action by the U.S. government; however, many of these recommendations are appropriate for OECD and developing nations who anticipate the use CCS.
1. The US Geological Survey and the DOE, and should embark of a 3 year “bottom-up” analysis of US geological storage capacity assessments. This effort might be modeled after the GEODISC effort in Australia.

2. The DOE should launch a program to develop and deploy large-scale sequestration demonstration projects. The program should consist of a minimum of three projects that would represent the range of US geology and industrial emissions with the following characteristics:

   • Injection of the order of 1 million tons CO\(_2\)/year for a minimum of 5 years.
   • Intensive site characterization with forward simulation, and baseline monitoring
   • Monitoring MMV arrays to measure the full complement of relevant parameters. The data from this monitoring should be fully integrated and analyzed.

3. The DOE should accelerate its research program for CCS S&T. The program should begin by developing simulation platforms capable of rendering coupled models for hydrodynamic, geological, geochemical, and geomechanical processes. The geomechanical response to CO\(_2\) injection and determination or risk probability-density functions should also be addressed.

4. A regulatory capacity covering the injection of CO\(_2\) accounting and crediting as part of a climate regime, and site closure and monitoring needs to be built. Two possible paths should be considered — evolution from the existing EPA UIC program or a separate program that covers all the regulatory aspects of CO\(_2\) sequestration.

5. The government needs to assume liability for the sequestered CO\(_2\) once injection operations cease and the site is closed. The transfer of liability would be contingent on the site meeting a set of regulatory criteria (see recommendation 4 above) and the operators paying into an insurance pool to cover potential damages from any future CO\(_2\) leakage.

CITATIONS AND NOTES

1. From a technical perspective, ocean sequestration appears to be promising due to the ocean’s capacity for storage (IPCC 2005). Presently, because of concerns about environmental impacts, ocean sequestration has become politically unacceptable in the US and Europe.

2. Terrestrial storage, including storage in soils and terrestrial biomass, remains attractive on the basis of ease of action and ancillary environmental benefits. However, substantial uncertainties remain regarding total capacity, accounting methodology, unforeseen feedbacks and forcing functions, and permanence.


5. A 1000 MW bituminous pulverized coal plant with 85% capacity factor and 90% efficient capture would produce a CO\(_2\) stream mass of 6.24 million t/yr. If injected at 2 km depth with a standard geothermal gradient, the volume rate of supercritical CO\(_2\) would be 100,000 barrels/day (for comparison, the greatest injection rate for any well in the world is 40,000 bbl/d, and typical rates in the US are <3000 bbl/d). This suggests that initially either multiple long-reach horizontal wells or tens of vertical wells would be required to handle the initial volume. Over 50 years, the lifetime typical of a large coal plant, this would be close to 2 billion barrels equivalent, or a giant field for each 1000 MW plant.


20. *Injectivity* is the rate at which CO$_2$ injection may be sustained over fairly long intervals of time (months to years); *Capacity* is the total volume of potential CO$_2$ storage CO$_2$ at a site or in a formation; *Effectiveness* is the ability of the formation to store the injected CO$_2$ well beyond the lifetime of the project.


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Chapter 5 — Coal Consumption in China and India

INTRODUCTION

China is expected to account for more than half of global growth in coal supply and demand over the next 25 years. The implications for the global environment are both complex and substantial. This chapter explores the circumstances under which China might constrain its carbon emissions from coal significantly below the currently forecast range. India, with a population comparable to that of China, a rapidly growing economy, and large domestic coal reserves, may one day come to rival China as a source of carbon emissions from coal. Like China, India derives over half of its commercial energy from coal, and together the two countries are projected to account for over 68% of the incremental demand in world coal through 2030.\(^1\) Today, however, India consumes only about a fifth as much coal as its neighbor, and for the foreseeable future the consumption gap between the two countries will remain wide. The main focus of this chapter is thus on China, but in the final section we briefly compare patterns of coal use in the two countries.

Coal is today China’s most important and abundant fuel, accounting for about two thirds of the country’s primary energy supply. Coal output in China rose from 1.30 billion tonnes in 2000 to 2.23 billion tonnes in 2005,\(^2\) making China by far the world’s largest coal producer (the next largest, the United States, produced 1.13 billion tonnes last year). All but a few percent of this coal is consumed domestically, and China’s coal use amounts to nearly a third of all coal consumed worldwide (see Figure 1). Electricity generation accounts for just over half of all coal utilization in China, having risen from 22% of total consumption in 1988 to over 53% in 2002.\(^3\) Coal currently accounts for about 80% of China’s electricity generation, more than 50% of industrial fuel utilization, and about 60% of chemical feedstocks. Forty-five percent of China’s national railway capacity is devoted to the transport of coal.\(^4\) The central government has announced its intention to reduce the country’s reliance on coal, but for the foreseeable future it will remain China’s dominant fuel, and will very likely still account for more than half of the country’s primary energy supplies in the year 2030. The largest contributor to future growth in China’s demand for coal will be the electric power sector.

The recent growth of the Chinese power sector has been dramatic. Electricity generation grew at a rate of 15.2% in 2003, 14.8% in 2004, 12.3% in 2005, and 11.8% (on an annual basis) in the first quarter of 2006.\(^5\) Total generating capacity increased by nearly a third in the last three years and is expected to double between 2002 and 2007. In 2005, about 70,000 MWe of new generating capacity was brought into service. A similar completion of new plants is projected for each of the next two years.\(^6\) At this rate, China is adding the equivalent of nearly the entire UK power grid each year. Most of the existing and new generating capacity is fueled with coal, and China’s coal-fired power plants are the main cause of the rapid increase in its greenhouse gas emissions, which are already the world’s second largest after the United States.
First, especially at the national level, China’s energy-related governmental bureaucracy is highly fragmented and poorly coordinated. Responsibility for energy pricing, for the approval of infrastructure projects, for the oversight of state energy companies, and for long-term energy policy is spread across many agencies, most of them seriously understaffed, and some of which—given their very recent emergence on the scene—are notably weak in relation both to other agencies and to the players they are supposed to be regulating.

Second, under these conditions the state energy companies—the national oil corporations and the national power generating groups—are the most coherent entities. These are the organizations that are most capable of defining their own interests and that are most likely to act, making decisions that their ostensible state regulators and overseers can barely keep up with and sometimes do not even monitor. At the same time, and reflecting China’s increasingly deep integration with the global economy, these corporate entities are hardly simple organizations themselves. Listed on both domestic and foreign stock exchanges, the state energy corporations encompass complicated groupings of stakeholders, including state-appointed senior executives, domestic and foreign corporate board members, major financiers from the global investment banking community, and international institutional investors. Textbook examples of shareholder-driven corporate governance they are not, but neither are they simple puppets of the state—in no small part because the state itself is so fragmented and lacks a clear voice on energy policy. In essence, the central government in Beijing today has neither a coherent national energy strategy nor much capacity to monitor, support, or impede the actions of state-owned energy companies—actions that are often misunderstood by outsiders as merely echoing government policy.

Figure 5.1 World Coal Consumption, 2004

Chinese energy statistics—including those pertaining to coal consumption and power generation—suffer serious problems of reliability. Data reported by both official and unofficial sources exhibit substantial variation and numerous inconsistencies. Indeed, different figures for annual coal consumption are noted in this chapter and in Chapter Two. But there is no dispute about the general trend exhibited by the data: Chinese energy consumption is trending rapidly upward.

The supercharged recent growth rates in the power sector may moderate in coming years, but the general trend of strong growth is likely to continue for a long time to come. Electricity consumption per capita in China, at about 1,700 kilowatt hours per year, is still only 20% of the average per capita consumption in the world’s advanced economies. Rapid economic development is changing the lifestyles and energy needs of hundreds of millions of Chinese citizens. Future demand growth on a large scale seems assured.

A full understanding of China’s current energy situation—including the types of fuels being consumed, the kinds of technologies employed, the effectiveness of environmental regulation, and the international reach of its enterprises—starts with three key characteristics of the Chinese system.
Third, and most important, the remarkably rapid growth of energy consumption in China has been possible because a host of infrastructural issues are being resolved very quickly by individuals and organizations operating well below the level of national energy corporations. Almost daily, actors at the grassroots level are making key decisions about China’s physical and technological infrastructure—decisions with profound consequences for its long-term energy development.

Thus, it is a mistake to attribute China’s aggregate energy demand growth—or even the actions of the state-owned energy companies—to central government agendas or geopolitical strategy. What many outsiders see as the deliberate result of Chinese national ‘energy strategy’ is in fact better understood as an agglomeration of ad hoc decisions by local governments, local power producers, and local industrial concerns. These local actors are primarily motivated by the need to maintain a high rate of economic growth and few, if any, have the national interest in mind. They are rushing to fill a void left by the absence of a coherent national-level energy strategy. Amidst surging energy demand and frenetic local decision-making in the central government are scrambling simply to keep abreast of developments on the ground. China’s astonishingly rapid energy development may well be spinning the heads of outsiders, but it is vexing, perplexing, and even overwhelming to Chinese governmental insiders too.

METHODOLOGY

The main conclusions of this chapter are based upon fieldwork conducted in China by a team based at the MIT Industrial Performance Center beginning in 2002, but concentrated primarily in 2005. Our goal was to study decision-making in the Chinese power and coal industry sectors. The study primarily employed a case-based approach, supplemented by extensive interviews at various levels of Chinese governmental, academic, and commercial circles. The cases center primarily on the electric power sector and they were selected to represent three general modes of energy-related problem solving in the Chinese system: (1) relatively standard coal-fired power generation by municipal-level plants; (2) “within the fence” self-generation (co-generation) by industrial users or other commercial entities operating outside of what is generally understood as the energy sector; and (3) more future-oriented regional efforts by China’s wealthiest coastal provinces to build a natural gas infrastructure.

(1) In the municipal power utility category, we focused our efforts on two sites, the 250 MWe Xiaguan Power Plant in Nanjing (Jiangsu Province) and the 1,275 MWe No. 1 Power Plant in Taiyuan (Shanxi Province). The Xiaguan facility, though formally owned by the national Datang Enterprise Group, is managed and administered primarily at the provincial and municipal levels. The facility is located in the downtown area of Nanjing, the capital of Jiangsu Province and a city of 1.8 million persons (the city has an additional 3.5 million suburban residents). Jiangsu, located on the east coast of China and encompassing much of the Yangtze River Delta, is among the most prosperous and industrialized regions of the country. Industry accounts for over 77% of provincial electricity consumption and (including the power sector) 92% of coal consumption, with residential following a distant second at 11% and 4.2%, respectively. Jiangsu is a center for numerous clusters of domestic and foreign-owned manufacturing operations, and relies primarily on coal imported from interior regions of China to meet its needs. In 2003 about 79% of the province’s total coal supply was imported. Nanjing consumes one quarter of Jiangsu’s electricity supply.

Nanjing’s Xiaguan Power Plant dates originally from 1910, but underwent a substantial rebuild from 1998 to 2000. Approximately 30 percent of the rebuild costs were devoted to the installation of a LIFAC (Limestone Injection into Furnace and Activation of Calcium oxide) flue-gas desulfurization system. At the time of
our research, three such systems were operating in China, two in the Nanjing facility and one in a 125 MW e power plant in neighboring Zhejiang Province. Xiaguan’s system was supplied by the Finnish firm POCOTEC Pollution Control Technologies, and was financed by soft loans from the Finnish government and grants from the Jiangsu provincial government. The system produces no secondary wastewater, and the fly ash is used for road construction and cement production. The Xiaguan plant generally burns coal with a sulfur content of 1.0 to 1.5 percent. The LIFAC system has achieved a 75% sulfur removal rate, and for the first five years of operation averaged more than 95% availability. Though a loss maker commercially over the past three years—a condition not unusual for Chinese generators—the plant has become something of a model nationally for advanced emissions control.

The second case in this category, the No. 1 Power Plant on the outskirts of Taiyuan City, Shanxi Province, is a more typical facility along a number of dimensions. Taiyuan is the capital of Shanxi, a landlocked province in North China and the largest coal-producing region in the country, supplying 27% of China’s coal in 2003.9 Mining is far and away the largest industry in the province, though a concentration of traditional, state-owned heavy manufacturing is clustered in Taiyuan City. The province, among the poorest in China in terms of urban income, has gained notoriety as the center of some of the country’s worst environmental problems, especially atmospheric pollution and acid rain. Approximately 70 percent of annual provincial production of energy resources are exported and sold to other provinces. Taiyuan City, with an urban population of about 2.3 million, consumes 40% of the province’s electricity supply. The city is covered in soot and has been ranked as having the worst air quality (particulates and sulfur dioxide) of any city in the world.10 In 2002, despite various regulatory efforts, reported average daily SO2 concentrations in Taiyuan equaled 0.2 milligrams per cubic meter (mg/m3), over three times the PRC’s Class II annual standard (0.06mg/m3).11

The Taiyuan No. 1 Power Plant, one of the largest sources of airborne pollutants in the city, went into operation in 1954, though the six units currently in operation—four 300 MW e generators, one 50 MW e generator, and one 25 MW e generator—date from the 1990s. The plant sources all its coal from within Shanxi province, and reports an inability to secure low-sulfur and low ash content coal. Flue-gas desulfurization facilities (wet limestone and gypsum spray injection systems imported from Japan) have been installed only on the 50 MW e unit and one of the 300 MW e units. The plant reports sulfur dioxide emissions of approximately 60,000 tonnes annually, about 20 percent of Taiyuan municipality’s annual total. The local Environmental Protection Bureau has routinely assessed emission fines on the No. 1 Power Plant which, when combined with low tariffs for power delivered to the grid, makes the facility uneconomic. Nevertheless, the facility is planning a major expansion, involving the addition of two 600 MW e generators. This expansion is driven in part by electricity shortages both within the inland province itself and in the Northern coastal areas to which power generated by the plant is dispatched. Shanxi Province exports approximately 25 percent of its electric power to coastal areas, with generators in the province facing particular pressure to dispatch to the distant, but politically powerful cities of Beijing and Tianjin. Our team also interviewed the state-owned Shanxi Grid Corporation to examine issues surrounding dispatch.

(2) In the category of co-generation for primary power by industrial firms, the research team focused on the coastal Southern Chinese province of Guangdong, where much development of this type has taken place. Guangdong, arguably the first Chinese province to undergo economic reform, is now one of the most economically liberal and internationally integrated regions of China. The province includes a number of major manufacturing clusters, many of which emerged only after the onset of economic reform and thus have avoided many of the historically-rooted problems of China’s northern and northeastern industrial
'rust belt' regions. The research team focused on two primary cases in this region.

One of the cases is a major Guangdong subsidiary of a Hong Kong-based global apparel concern. This subsidiary employs 23,000 individuals in a major production site in the city of Gaoming. The company’s factories in Gaoming and nearby Yanmei consume about 170 thousand megawatt-hours of electricity and 600,000 tonnes of steam annually, accounting for 8–9% of total operating costs. The firm was confronted with electricity shortages which were constraining its expansion, and in 2001 elected to build its own 30 MWe coal-fired co-generation plant. The plant became operational in 2004. The plant burns low sulfur coal sourced from Shanxi and Inner Mongolia. Coal costs for the company have risen substantially over the last two years (from 330 RMB/ton to 520 RMB/ton), making the in-house plant's electricity costs only marginally lower than grid electricity. Unlike the grid, however, the in-house plant provides reliable energy, as well as substantial quantities of steam, which avoids the need for costly and environmentally problematic heavy oil burners.

The second self-generation case involves the Guangdong manufacturing site of a U. S. consumer products company. This firm faced similar energy constraints, albeit on a smaller scale, at its production facilities outside the provincial capital, Guangzhou. The bulk of the site's energy use is accounted for by the heating, ventilation and air-conditioning requirements of its climate-sensitive manufacturing facilities. In the last two to three years, the firm has routinely received electricity-shedding orders from the regional grid company, requiring a shift in production schedules to avoid periods of peak power consumption. The shedding orders have ranged from 30 to 70 percent of total load, thus challenging the firm's HVAC requirements and threatening its manufacturing operations. Fearing further energy-related disruptions, the firm elected to purchase dual Perkins diesel-fired generators, each rated at 1.8 MWe.

To supplement these case studies, the team conducted interviews with major multinational suppliers of diesel generators to the China market, as well as with industrial and governmental purchasers of diesel generators in North China, a region in which these generators are usually employed as back-up sources of power.

(3) Members of the research team have also undertaken a multi-year effort into the third category of energy decision-making, gas infrastructure development in coastal East China. Interviews and discussions have been conducted with a variety of involved entities, including overseas fuel suppliers, Chinese national oil and gas majors, port facility and pipeline development companies, national and local governmental development agencies, domestic bank lenders, and overseas investors. This is a large topic that extends beyond the scope of the chapter. However, we include it as an important illustration of the politics of energy-related issues in China, as an important indicator of future energy infrastructure trends in the country, and as a bridge between China’s domestic energy imperatives and global energy markets.

**CAPACITY EXPANSION IN THE ELECTRIC POWER SECTOR.**

Capacity expansion in China’s electric power sector provides us with some of the clearest evidence of how energy-related decisions are actually being made on the ground. On paper, the story is straightforward. Most power plants belong to one of five major state-owned national energy corporations, enterprise groups that in theory answer upward to the central government while issuing orders downward to exert direct financial and operational control over their subsidiary plants. This chain of command should mean that for a new power plant to be built, the state-owned parent must secure the necessary central government approvals, and demonstrate that the new project meets relevant national technical standards, stipulations about what fuels to utilize, and, once the plant is up and running, national
operational requirements, including environmental regulations.

The reality, however, is far more complex. For example, as central government officials themselves acknowledge, of the 440,000 MWe of generating capacity in place at the beginning of 2005, there were about 110,000 MWe of ‘illegal’ power plants which never received construction approval by the responsible central government agency (the Energy Bureau of the National Development and Reform Commission, a part of the former State Planning Commission.) These plants were obviously all financed, built, and put into service, but nobody at the center can be sure under what terms or according to what standards.

Local government dynamics are critical to an understanding of China’s fragmented energy governance. In China today, localities in high growth industrialized regions like the coastal provinces Zhejiang and Guangdong desperately need electricity. Local officials, long accustomed to operating in a bureaucratic system that for all its confusion has consistently emphasized the maximization of economic growth and consistently tolerated ‘entrepreneurial’ ways of achieving that goal, are the key players in power plant construction and operation. For example, the parent national energy corporations provide only about 25% of the capital required for new power plant investment. Much of the remainder comes in the form of loans from the municipal branches of state-owned banks. These banks in theory answer to a headquarters in Beijing, but in practice are likely to respond to the wishes of local governmental officials, partly because local officialdom exerts substantial control over personnel appointments within local bank branches. Another important source of capital is even more directly controlled by the locality. These are municipally-owned energy development corporations—quasi-commercial investment agencies capitalized through various fees and informal taxes levied by local government.

Thus, regardless of formal ownership ties running up to the center, power plants built for the urgent purpose of meeting local demand are often built with locally-controlled financing. It should not be surprising, then, to find municipal governments providing construction approval to get the plants online as quickly as possible, while simultaneously shielding them from the need for further approvals from the center that might well require stricter technical, environmental, or fuel standards. Similarly, parent power firms and local governments will often break apart plant investment filings in an attempt to lower artificially the plant’s recorded capacity and therefore avoid the need for central government approval. The fact that 110,000 MWe of installed capacity is ‘illegal’ means neither that the plants are hidden in a closet nor that they lack any governmental oversight. What it does mean is that they are not part of a coherent national policy, that they frequently operate outside national standards, and that they often evade control even by their ostensible owner at the national corporate level.

In this system, the lines of operational accountability and responsibility are often blurred. On the one hand, power plants that are supposed to be controlled by a parent national firm end up dealing with the parent at arms length. The parent provides some investment and working capital funds to the plant, and some profits are returned upward. In accounting terms, the financial performance of the plant is subsumed within the integrated financial statement of the parent corporation. On the other hand, financing and project approval come primarily through local agencies that are intent on ensuring power delivery regardless of the commercial ramifications for the plant or the parent group. Thus, power plants can and do operate at a loss for years on end, further complicating incentives for plant managers. Indeed, because of the lack of clarity in the governance structure these operators sometimes themselves engage in creative financial and investment strategies. Central officials acknowledge that it is not unusual for power plants to operate sideline, off-the-books generating facilities, the profits
from which can be hidden from the parent energy group and thus shielded from upward submission. As one Chinese government researcher recently observed, the electric power sector may be a big loss maker on the books, but people in the sector always seem to have a great deal of cash. Of course, the high rates of capacity increase mentioned earlier could not happen without local government compliance, if not outright encouragement. China's fastest growing cities are effectively pursuing a self-help approach to meeting their power needs, and blurred lines of governance and accountability abet them in this.

ENVIRONMENTAL REGULATION.

Chinese environmental administration is also characterized by a pattern of de facto local governance. For example, the central government has established extensive legal restrictions on emissions of sulfur dioxide. The 1998 and 2000 amendments to China's Law on the Prevention and Control of Atmospheric Pollution set stringent national caps on total sulfur emissions and required coal-fired power plants to install pollution-reducing flue gas desulfurization systems. To promote the utilization of these technologies, which add significantly to plant capital and operating costs, the central government imposed mandatory pollution emission fees on power plants. Yet today, the central government estimates that only about 5,300 MWe of capacity has been equipped with FGD, a small fraction of the total capacity subject to the anti-pollution laws. Another 8,000 MWe with FGD is currently under construction, but even once completed, the resulting total will still only equal about 5.4% of thermal capacity. Even more troubling, researchers could only guess at how often the equipment is actually turned on.

Once again, the fragmented, ad hoc system of energy-related governance in large part explains how this could happen. Environmental policy at the national level is primarily the responsibility of the State Environmental Protection Agency (SEPA), a relatively weak organization, though one that has been gaining authority recently. But implementation and enforcement come under the authority of provincial and municipal-level arms of SEPA. As with the local bank branches, personnel appointments in these local environmental bureaus are for the most part controlled by local governmental officials rather than by the parent central agencies. If the locality's main goal is to achieve economic growth, and cheap electric power is needed to fuel that growth, then environmental enforcement will play a secondary role. Local environmental officials who take a different view are likely to run into career difficulties. Moreover, budget allocations for local environmental bureaus are very tight, so bureau officials are often forced to resort to self-help mechanisms of financing just to survive. To keep up staffing levels and ensure that their employees are paid, they must rely either on the collection of local pollution emission fees or on handouts from the local government. In practice, this translates into incentives for local environmental regulators either to allow emitters to pollute (as long as they compensate the local SEPA office with the payment of emission fees) or to accept payment from the local government in return for ignoring emissions entirely.

WITHIN-THE-FENCE GENERATION.

In the fastest-growing and most power-hungry areas of China the self-help approach goes right down to the level of the industrial enterprises that account for so much of the growth in electricity demand. In provinces like Guangdong and Zhejiang, major industrial cities have grown up out of what only recently were small towns or villages. In the absence of adequate municipal or regional power infrastructure, large numbers of manufacturers in these areas have been installing their own diesel-fired generators. The diesel fuel is expensive, and the electricity is more costly than from a large coal-fired power plant. But the factories have little choice. Many of them are tightly integrated into global production networks and are scrambling to meet overseas
demand for their products. They cannot afford to shut down for lack of power. Some of them operate sensitive production processes that do not tolerate power interruptions. The scale of such activities is considerable. In Zhejiang province, for example, it is estimated that 11,000 MWe is off-grid. China is now the world’s largest market for industrial diesel generators, and the country’s consumption of diesel fuel, much of it produced from imported crude, has climbed substantially. Generator manufacturers estimate that ten percent of China’s total electric power consumption is supplied by these ‘within-the-fence’ units. Local officials have generally tolerated and in some cases actively supported such solutions, and environmental regulation of these diesel generators has lagged behind that of central station power plants.

THE PATH FORWARD: COAL VERSUS OIL AND GAS.

The complicated, fragmented governance of China’s energy sector will also have a major bearing on one of the most important aspects of its future development: the relative roles of coal, on the one hand, and oil and natural gas, on the other. The vast scale of China’s demand suggests that all economic energy sources, including nuclear power and renewables, will be used heavily. But in China, as in the world as a whole, fossil fuels will dominate the supply side for the foreseeable future. (China’s ambitious plans for nuclear power underscore this point. If current plans come to fruition, and nuclear generating capacity is increased from its current level of about 9,000 MWe to 40,000 MWe by the year 2020, more nuclear plants will be built in China over the next 15 years than in any other country. But even then, nuclear energy will still only provide about 4% of China’s generating capacity. Fossil-fired plants will account for much of the rest.)

The inevitable dominance of fossil fuels in China is not good news for the global climate. But the severity of the problem will depend on the proportions of oil, gas, and coal in China’s future energy mix, and that is much less certain. In one scenario, China, like almost every country that has preceded it up the economic development ladder, will rapidly shift from reliance on solid fuels towards oil and gas, with gas playing an increasingly important role in electric power generation, in industrial and residential heating, and potentially also in transportation.

In an alternative scenario, China will remain heavily dependent on coal for electric power, for industrial heat, as a chemical feedstock, and increasingly, for transportation fuels, even as demand continues to grow rapidly in each of these sectors. The prospect of continued high oil and gas prices make the coal-intensive scenario more plausible today than it was during the era of cheap oil.

These two scenarios pose very different risks and benefits for China and for the rest of the world. For the Chinese, the heavy coal use scenario would have the merit of greater energy autonomy, given China’s very extensive coal resources. It would also mean less Chinese pressure on world oil and gas markets. But the impact on the environment would be substantially greater, both locally and internationally. In the worst case, the heavy environmental toll inflicted by today’s vast coal mining, shipping, and burning operations, already by far the world’s largest, would grow much worse as China’s use of coal doubled or even tripled over the next 25 years. More optimistically, China would become the world’s largest market for advanced clean coal technologies, including gasification and liquefaction, and eventually also including carbon dioxide capture and storage. But these technologies will add considerably to the cost of coal use, and, in the case of carbon capture and sequestration, are unlikely to be deployable on a large scale for decades.

The high oil and gas use scenario would not prevent these problems, but it would make them more manageable. A modern gas-fired electric power plant is not only cleaner than its coal-fired counterpart, but also emits 70%
less carbon dioxide per unit of electrical output. A petroleum-based transportation system emits only about half as much carbon dioxide per barrel as it would if the liquid fuels were produced from coal. But the high oil and gas scenario would also force China, with few resources of its own, to compete ever more aggressively for access to them around the world. In that case, the recent tensions with Japan over drilling in the East China Sea and the flurry of deal making in Iran, Africa, Central Asia, South America, and elsewhere may in retrospect come to seem like a period of calm before the storm.

Much is riding, therefore, on which of these scenarios China will follow more closely. There are already some indications of which way China will go. China’s coal is for the most part located inland, far from the major energy consuming regions along the coast. So a clean-coal-based development strategy would require a national-scale energy infrastructure, with large-scale, technologically-advanced, highly efficient power plants and ‘polygeneration’ facilities (producing a mix of chemical products, liquid transportation fuels, hydrogen, and industrial heat as well as power) located in the coal-rich areas of the north and west, and linked to the coastal regions via long-distance, high-voltage transmission networks. But although numerous demonstration projects have been proposed or even in some cases started, both participants and other domestic advocates frequently express frustration at the slow pace of development and inconsistent government support for these efforts. Despite years of deliberation, many of the highest profile projects are still held up in the planning or early construction phases.

A major obstacle is that these clean-coal-based strategies require a strong central government role, centralized funding, and substantial cross-regional coordination, all of which are lacking in China’s energy sector today. Instead, China’s most-developed coastal regions, rather than waiting for a national strategy to emerge, are moving forward with their own solutions. Many municipalities are simply building conventional coal-fired power plants as fast as they can, often with subpar environmental controls. While they are willing to import coal from the poorer inland provinces, they are not willing to invest in the large-scale infrastructure that would make them dependent on electricity generated in those interior regions. It is commonly observed that in China everybody wants to generate power, and nobody wants to rely on others for it.

More developed provinces like Zhejiang and Guangdong, or provincial-level municipalities like Shanghai, under pressure to provide adequate power supplies but also facing growing demands by an increasingly sophisticated public for a better environment, recognize the need for cleaner approaches. However, these wealthier regions are investing not in clean coal, but rather in a burgeoning natural gas infrastructure, based mainly on liquefied natural gas (LNG) imports. In this, their interests coincide with those of the state petroleum companies, which have become significant investors in—and builders of—the infrastructure of port facilities, terminals, LNG regasification plants, pipelines and power plants, frequently partnering in these projects with the energy development arms of the municipalities and provinces. Since the viability of these investments depends on the availability of natural gas, the state petroleum companies have recently been focusing their overseas acquisition activities at least as much on gas as on oil. CNOOC’s recent bid for Unocal, for example, was motivated as much or more by Unocal’s natural gas reserves than by anything having to do with oil.

In effect, commercial and quasi-commercial interests at the local and national levels—almost always in cooperation with international investors—are moving China’s coastal regions, if not China as a whole, down a natural gas-intensive path. Recent increases in the price of gas are playing a key role in these decisions, but that role is by no means straightforward. As noted previously, many of the key decision-makers—particularly those at the grassroots level who are influencing national policy
through ‘fait accompli’ commercial deals and investment programs—often simultaneously play the roles of policy designer, regulator, investor, commercial operator, and commercial fuel supplier. At times, their commercial stakes extend across the supply chain, from ownership of overseas fuel assets to management of shipping and logistics, investment in domestic port and infrastructural facilities and ownership of power generation. Thus, a given decision-maker may simultaneously view the prospect of higher-priced gas imports negatively from a regulatory perspective and positively in commercial terms.

In fact, more than any other players in the Chinese system, those who are participating in the gas and petroleum supply chains are the organizations with cash, commercial sophistication, links to global partners, access to global fuel supplies, and ready entrée to downstream infrastructure and major energy consumers. It is they who are making national energy policy, whether by design or—simply by virtue of the speed with which they are executing commercial strategies—by default. And none of them—not the national fuel and power firms nor the decision-makers in the leading coastal provinces—has much incentive to advocate advanced coal-based solutions or technologies. For the state petroleum firms, which increasingly see themselves as gas companies and hold substantial cash reserves, coal is a substitute for their products and the coal industry a competitor. Large-scale clean coal solutions are unlikely to be much more appealing to the national power companies, the nominal parents of most of China’s coal-burning plants. Large-scale clean coal is associated with power generation at the mine mouth, which in turn is associated with control by the mining industry, and the power companies have little interest in yielding control of their industry to mining concerns.

Finally, even though price will surely be important in the long run, powerful provincial and municipal governments along the industrialized coast, facing rapidly growing local power demand and able to draw on substantial investment resources to meet it, seem at present to be opting for dependence on foreigners for gas over dependence on interior provinces for coal. The Shanghai government last year banned the construction of new coal-fired plants, while at the same time working to build an LNG infrastructure. Some coastal municipalities have little choice but to rely on coal from the interior in the near term, though even here they maintain control over power generation through the exercise of financial and regulatory power, and by building new coal plants scaled to serve only local or intra-provincial needs. However, the real trend-setters over the long term, the richer and more advanced municipalities like Shanghai, are pursuing self-help on a grand scale by investing in natural gas infrastructure. In effect, they are tying themselves to overseas natural gas supplies while maintaining a regulatory and financial stake in the downstream gas infrastructure. As they partner in these projects with national energy companies, they become at once investors, producers, consumers, and regulators of the natural gas business. This is all done in lieu of national-scale advanced coal solutions which would remove from their control not only the fuel but the power generation business as well.

THE OUTLOOK FOR CHINA

In light of this fragmented system of governance, what can the West expect of China in those aspects of its energy development that matter most to us? What, if anything, might be done to influence China’s energy development in a favorable direction?

First, we should recognize that the Chinese government’s capacity to achieve targets for reducing hydrocarbon consumption or pollutant releases, or Kyoto-like limits on greenhouse gas emissions, is in practice quite limited. Neither louder demands for compliance by outsiders nor escalating penalties for non-compliance are likely to yield the desired results. China’s national leadership may eventually be prepared to enter into such agreements, but if
so those undertakings should be understood primarily as aspirational. China’s system of energy-related governance makes the fulfillment of international commitments problematic. Nevertheless, those commitments can serve as an important source of domestic leverage for leaders seeking to strengthen internal governance in the long run.

The Chinese central government’s recently announced goal of increasing national energy efficiency by 20 percent over the next five years can be understood in analogous terms. Key actors within the central government have grown increasingly aware of China’s energy vulnerabilities and of the urgent need for more sustainable utilization of energy resources. Public commitments to efficiency targets, by putting the central government’s reputation on the line, suggest at the very least serious aspirations—probably a necessary condition for real change to occur, though by no means a sufficient one. The question now is whether, given the nature of governance obtaining across the system—vast decentralization, ambiguous boundaries between regulatory and commercial actors, and overriding norms of economic growth maximization—there exists systemic capacity to meet the center’s aspirational goals.

Second, the authoritarian nature of the Chinese state does not mean that the state itself is internally coherent or effectively coordinated. Indeed, even with regard to the recent energy efficiency targets, substantial differences of opinion persist among various agencies and actors at the central level. One result of China’s particular path of reform is that the boundaries between state and non-state, public and private, commercial and non-commercial, and central and local have all become blurred. China’s increasingly deep integration into the global economy is even blurring the distinction between foreign and domestic. The Chinese energy companies are majority-owned by the state (though who actually represents the state is open to debate), but they also list on overseas stock exchanges, have foreigners among their corporate directors, and receive financing and guidance from international investment banks. As a practical matter, the number of actors exercising de facto decision-making power over energy outcomes in China is large, and they are not exclusively confined within China’s borders. We should not reflexively invest the actions even of the ostensibly state-owned Chinese energy entities with geostrategic intent. Nor should we assume that those in the center who do think in terms of crafting a national energy policy actually can control the very large number of entities whose actions are often driving energy outcomes.

For those outside China who have a stake in the direction of China’s energy development, the governance situation we have described here has both positive and negative implications. On the one hand, this is not a system that is capable of responding deftly to either domestic or international mandates, particularly when such mandates call for dramatic near-term change, and particularly when such change carries economic costs. Indeed, the response by subordinate officials to dictat from above is more likely to come in the form of distorted information reporting than actual changes in behavior. The response by local officials in the late 1990s to central mandates for closure of locally-owned coal mines—a response that generally involved keeping local mines open but ceasing to report output to national authorities—is indicative of how the system reacts to dictat. The many players, diffuse decision making authority, blurred regulatory and commercial interests, and considerable interest contestation in the energy sector combine to make dramatic, crisp changes highly unlikely. It is illusory to expect that the world’s carbon problem can somehow be solved by wholesale changes in Chinese energy utilization trends.

On the other hand, this is also system in which players are emerging at every level who have a stake—whether political or commercial—in achieving more sustainable energy outcomes. That some central agencies have been able to establish more stringent national energy ef-
iciency targets, that citizens in China’s more advanced cities like Shanghai (a municipality with a per capita income comparable to Portugal’s) are demanding cleaner air, and that domestic energy companies are positioning themselves commercially for an environmentally-constrained market are just some of the indicators of this. Although these players are not well coordinated, and often represent competing interests themselves, they are frequently looking outside, particularly to the advanced industrial economies, for guidance and models to emulate. Moreover, they are doing so in the context of a system that is highly integrated into the global economy, to the point that foreign commercial entities are often deeply involved in domestic decision making. This is particularly apparent with respect to corporate strategy (including the strategies of the state energy companies), investment preferences, and technology choices. In short, there may be significant opportunities, especially through commercial channels, for foreign involvement in China’s pursuit of sustainable energy development.

Perhaps most important, for all its faults the Chinese system is highly experimental and flexible. Those entities that are seeking more sustainable energy solutions in many cases actually have the ability to pursue experimental projects, often on a large scale and often involving foreign players. For example, several municipalities, including Beijing itself, have taken advantage of aspects of the national Renewable Energy Law to establish cleaner, more efficient, large-scale biomass-fueled power plants. The specific terms of such projects—who pays for them, who designs and controls them, and so on—are always subject to ambiguity, negotiation, and ad hoc interpretation. This is, after all, a nation that has an institutional tolerance for “systems within systems” and a wide array of quasi-legal, gray area activities. Experiments on the sustainable energy front are certainly possible, and in some cases are beginning to happen. Those most likely to succeed will not be national in scale, but localized, replicable, and able to propagate to other localities. These experiments should also be consistent with trends in advanced economies, and indeed, should be supported by players from those economies. China’s economic and commercial development is now so dependent on global integration that it will not be an outlier in terms of its energy system.

Finally, we should recognize that China’s energy system is in its own way as politically complex, fractured and unwieldy as our own. And we would be unwise to expect of the Chinese what we do not expect of ourselves.

**CHINA AND INDIA COMPARED**

India, with a population almost as large as that of China (1.1 billion compared with 1.3 billion) and with a similarly rapid rate of economic growth, will also be a major contributor to atmospheric carbon emissions. Like China, India has extensive coal reserves (see Figure 2.1), and it is the world’s third largest coal producer after China and the United States. Coal use in India is growing rapidly, with the electric power sector accounting for a large share of new demand. However, India’s per capita electricity consumption, at 600 kWe-hr/yr, is only 35% of China’s, and its current rate of coal consumption (460 million tonnes in 2005) is about a fifth that of China.

India’s total installed generating capacity in the utility sector in 2005 was 115,000 MWe, of which 67,000 MWe, or 58%, was coal-fired. Coal currently accounts for about 70% of total electricity generation. (The comparable figures in China were about 508,000 MWe of total installed capacity, with coal plants accounting for over 70% of installed capacity and about 80% of generation.) In India, as in China, self-generation by industry is also a significant source of coal demand.

A large fraction of future growth in the electricity sector will be coal-based. Current government plans project growth in coal consumption of about 6%/year. At this rate, India’s coal use would reach the current level of U.S. coal consumption by about 2020, and
would match current Chinese usage by about 2030. This suggests that there may be time to introduce cleaner, more efficient generating technologies before the greatest growth in coal use in the Indian power sector occurs.

Further information on India’s patterns of coal use is provided in Appendix 5.A.

CITATIONS AND NOTES

Chapter 6 — Analysis, Research, Development and Demonstration

In the United States, most of the energy supply and distribution activity, for example oil and gas production, coal mining, electricity generation, is performed by private sector firms. These firms make the massive investments required to sustain the energy system of the country and to develop and introduce new technology to the market.

Government support for this industry innovation occurs in four ways: (1) setting the rules for private sector innovation and technology deployment incentives, e.g., intellectual property protection and R&D tax credits; (2) support for basic scientific research; (3) support for pre-commercial technology and engineering development, and (4) support for demonstration projects that inform industry about the technical performance, cost, and environmental risks of a new technology. Support of pre-competitive research by government offers new technology options because private firms generally will not make investments whose benefits are not easily captured by individual firms. The rationale for later stage government support turns on other market failures or imperfections. These rationales are sometimes distorted in the political process so as to provide inappropriate subsidies, but significant learning-by-doing economies and social insurance considerations can be, under the right circumstances, sound rationales, along with other features like cost sharing.

The DOE is the primary federal sponsor of energy technology RD&D in the U.S. Because of the enormous coal resource base in the United States and the environmental challenges associated with its large-scale use, coal has been a major focus of the DOE RD&D program for more than thirty years. We comment on the extent to which the ongoing DOE RD&D effort is providing important options for meeting the principal challenges facing large-scale coal use in the coming years and decades. We also suggest the RD&D priorities we consider to be most critical and provide a rough estimate of the needed resource commitments.

The United States and other countries will want to use coal in the future because it is cheap and plentiful. But, in order to do that, technology must be available to control carbon dioxide emissions. The challenge applies both to new power plants and to improvement or retrofit of the large installed base of PC power plants.

The United States also has an interest in coal technology deployment in the large emerging economies such as China and India, principally because these countries are major emitters of greenhouse gases. A secondary interest is the potential commercial opportunity for U.S. firms to participate in the CO₂ emission control programs these large developing economies may offer. For some time, developing countries will be primarily interested in coal technologies that reduce emission of pollution that affects human health and the local and regional environment. The possible synergy between control of criteria pollutants and mercury, and the control of CO₂ emissions is an important factor in assessing the effectiveness and balance of the RD&D portfolio.

The critical technology options for meeting the challenge of CO₂ emission reduction are:
- ultra-high efficiency coal combustion plants
- gasification technologies, including gas treatment
- long-term carbon dioxide sequestration
- improved methods for CO₂ capture and for oxygen production
- syngas technologies, such as improved hydrogen-rich turbine generators and technologies to convert syngas to chemicals and fuels
- technologies that tolerate variable coal qualities
- integrated systems with CO₂ capture and storage (CCS)
- novel concepts, such as chemical looping, the transport gasifier, the plug flow gasifier, membrane separation of CO₂, and others
- large-scale transport of CO₂ captured and pressurized at coal combustion and conversion plants, to injection at storage sites.

In addition, some large-scale demonstration is needed in the near term:

- large-scale sequestration with appropriate site characterization, simulation, measurement, and monitoring;
- integrated coal combustion and conversion systems with CCS.

THE CURRENT DOE RD&D PROGRAM

A key question is the success the DOE RD&D program has had in providing these needed technologies in the past and its likelihood of success going forward. Our conclusion is that the DOE coal RD&D program has had some important successes over the last thirty years, but it has had some significant gaps and needs considerable strengthening and restructuring to meet the current challenges facing coal use.

Since 1978 the DOE has supported a broad effort of RD&D on advanced coal technologies for: (a) coal processing, (b) environmental control, (c) advanced power generation, (d) CO₂ capture and sequestration, and (e) industrial coal applications. A number of these activities have been undertaken in cooperation with industry and other organizations such as EPRI.

Figure 6.1 presents a timeline of the major RD&D program components. Since 1978 DOE has spent about $10 billion (2003 $) on these activities. The Clean Coal Technology Demonstration Program focused on commercial scale demonstration of technologies to improve the efficiency and reduce the environmental impact of coal-fired power generation. The Power Plant Improvement Initiative focused on demonstrating near-term technologies for improving environmental and operational performance of the PC fleet. The current Clean Coal Power Initiative is directed toward demonstrating innovative technologies to help meet the Clear Sky Initiative, the Global Climate Change Initiative, FutureGen, and the Hydrogen Initiative. FutureGen is intended to demonstrate the first commercial-scale, near-zero-emissions, integrated sequestration and hydrogen production power plant. The Advanced Research program is designed to develop the underlying basic science and innovative technologies to support the demonstration programs.

A summary of the FY07 Administration budget request for coal RD&D is presented, along with FY06 funding, in Table 6.1. The central role projected for FutureGen is evident. The table provides a reference point for our discussion of the principal ARD&D needs. We do not believe that the proposed DOE program can adequately address those needs with the proposed scale and distribution of funding.

COMMENTS ON THE DOE RD&D PROGRAM.

Our purpose here is to comment on the successes and gaps in the DOE’s program from the point of view of producing technology options for clean coal combustion and con-
version technology. We do not intend to do a detailed analysis of the DOE budget, or to assess its relationship to various roadmaps developed by DOE in partnership with others, notably the Coal Utilization Research Council and EPRI (for example, the Integrated Clean Coal Technology Roadmap [2]). We do not evaluate the program in terms of return on investment [1]. We also do not address the criticism that over the years the DOE coal program has been subject to political influence on project selection, siting, and structure.

The DOE program can be credited with a number of significant achievements.

Table 6.1 DOE Coal RD&D Program Overview for FY06 to FY07

<table>
<thead>
<tr>
<th></th>
<th>FY05, $MM</th>
<th>FY06, $MM</th>
<th>FY07, $MM</th>
<th>FY08, $MM</th>
<th>06 TO 07, $MM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Program, Total</td>
<td>342.5</td>
<td>376.2</td>
<td>330.1</td>
<td>-46.1</td>
<td></td>
</tr>
<tr>
<td>Clean Coal Power Initiative</td>
<td>47.9</td>
<td>49.5</td>
<td>5.0</td>
<td>-44.5</td>
<td></td>
</tr>
<tr>
<td>FutureGen</td>
<td>17.3</td>
<td>17.8</td>
<td>54.0</td>
<td>203.0</td>
<td>36.2</td>
</tr>
<tr>
<td>Innovations for Existing Plants</td>
<td>25.1</td>
<td>16.0</td>
<td>91.9</td>
<td></td>
<td>-9.1</td>
</tr>
<tr>
<td>IGCC</td>
<td>55.9</td>
<td>54.0</td>
<td>12.8</td>
<td>-5.0</td>
<td>-1.9</td>
</tr>
<tr>
<td>Advanced Turbines</td>
<td>17.8</td>
<td>12.8</td>
<td>54.0</td>
<td>17.6</td>
<td></td>
</tr>
<tr>
<td>Carbon Sequestration</td>
<td>66.3</td>
<td>73.9</td>
<td>12.8</td>
<td>5.6</td>
<td>7.6</td>
</tr>
<tr>
<td>Fuels (Hydrogen Focused)</td>
<td>28.7</td>
<td>22.1</td>
<td>28.9</td>
<td>-6.6</td>
<td>-23.7</td>
</tr>
<tr>
<td>Advanced Research</td>
<td>52.6</td>
<td>28.9</td>
<td>54.0</td>
<td>12.8</td>
<td></td>
</tr>
<tr>
<td>Subtotal, Coal Research Initiative</td>
<td>313.7</td>
<td>266.7</td>
<td>28.0</td>
<td>-47.0</td>
<td></td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>61.4</td>
<td>63.4</td>
<td>2.0</td>
<td>-1.0</td>
<td></td>
</tr>
<tr>
<td>U.S / China Energy</td>
<td>1.0</td>
<td>0.0</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
For PC systems, the DOE has contributed to advances in developing fluid-bed technology for power generation, and commercially demonstrating Circulating Fluidized Bed technology; demonstrating low-NO₃ burners, Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) for NOₓ control; improved Flue Gas Desulfurization (FGD) scrubbers for SOₓ control; and advancing mercury emissions quantification and mercury control technologies for PC plants.

For IGCC systems, the DOE has contributed to advances in improved syngas clean-up systems, advanced turbines (GE-H turbine, and Siemens-Westinghouse 501G), helping bring IGCC to the demonstration stage, and supporting two commercial demonstrations (Tampa Electric IGCC Project, 250 MWₑ and Wabash River Coal Gasification Repowering Project, 262 MWₑ) that provided significant information on the design and operation of utility-scale IGCC plants. As discussed in Chapter 3, in the past, the reason for support of IGCC demonstrations was to gain utility-scale experience with a technology that could be key if CO₂ capture would be required, although other reasons such as deep and efficient control of criteria pollutants and mercury, and polygeneration of multiple products, have also been suggested as benefits.

Public support was justified at the time as demonstration or risk reduction in integrating, at scale, the gasification/processing island with the power island. This integration posed substantial challenges: different syngas requirements from gasification applications that used coal instead of residual oil or coke as a feed stock; associated turbine operational requirements; different response times of the gasification and power components to load variations; bringing together distinct cultures for operating chemical and power plants; new design decisions concerning degree of heat and air integration, and trading off reliability concerns against operating efficiency.

Not all of these early DOE IGCC demonstration projects succeeded, but the Tampa and Wabash plants, in particular, provided valuable information. Useful information came from learning how these plants, and two similar scale plants in Europe, overcame difficulties in achieving reliable operation. For example, the Tampa Electric project had significant cost overruns and took five years to reach reliable operation, neither of which would be acceptable for a commercial project using established technology. However the project eventually realized over 80% availability operating with a single gasifier, and over 90% with backup fuel (natural gas) to the turbine. Today, the plant is a reliable contributor to that utility’s base load electricity supply, at acceptable operating cost. The lessons learned will inform future IGCC plant investment decisions, as intended in such government-supported demonstrations.

Although there are remaining concerns about capital cost and availability, our judgment is that for IGCC without CCS, the remaining risks are at a level that the private sector commonly encounters in making investment decisions on specific projects. Our judgment is supported by the formation of several industrial consortia to make commercial offers for IGCC plants without CCS. Accordingly, we see no justification for further public subsidy of IGCC plants without CCS on the basis of first-mover technical uncertainty; it is not an appropriate government role to “buy down” costs of technologies that are not directly addressing a market imperfection.

Demonstration of novel technologies is best done at the sub-system level. On the other hand, the critical step of adding CCS to an IGCC plants leads again to performance risks outside the envelope of private sector risk-taking and merits appropriately structured public support for integrated systems.

However there have been important gaps in the DOE program — we mention four:

1. There has been too little emphasis on improvements in PC generating efficiency, such as support for ultra-supercritical boiler and steam cycle technology. Europe and
Japan are more advanced in this technology with a number of large, ultra-supercritical units operating; in the United States, EPRI is taking the lead with DOE support.

(2) There is a significant lack of modern analytical and simulation tools for understanding the dynamics of complex integrated coal systems, particularly with CCS. Moreover, it does not appear to us that the private sector has adequately developed such tools either. The result is that neither the public nor private sector has the ability to assess tradeoffs between different technology options for carbon capture efficiency, much less analyze in sufficient depth questions such as transient behavior, plant reliability, or retrofit optimization.

(3) The applied research and technology program has not been robust enough to support the demonstration projects or to explore potential for future innovations.

(4) The DOE has been slow to support advanced technology at process development unit (PDU) scale that explores new options for coal conversion, oxygen separation, and for CO₂ capture.

In our view there is a near term need for appropriately structured, publicly supported, adequately resourced demonstrations of large-scale sequestration and of integrated coal combustion and conversion systems with CCS. We comment on components of the current DOE RD&D program that address important elements relevant to this purpose.

SEQUESTRATION

The DOE Carbon Sequestration Core Program was initiated in 1999 and has been supported with moderate but increasing funding (the proposed FY07 budget is $74 million, an 11% increase over FY06).

The program includes activities that cover the entire carbon sequestration cycle of capture, separation, compression, transportation and storage. The program has advanced carbon sequestration science and technology. The DOE program has promoted the formation of seven U.S. regional partnerships to build an information base for decision-making, including categorization and description of regional sources, sinks, and potential targets for pilot injections. The DOE and the State Department have established a Carbon Sequestration Leadership Forum as a platform for international collaboration on technical, regulatory, and policy issues in carbon sequestration.

To date, the DOE CCS program has not been pursued with an urgency to establish the key enabling science and technology needed for increased coal use in a carbon-constrained world. Importantly, developing advanced capture technologies or deployments of IGCC motivated by “capture readiness” are infeasible if sequestration is not possible at very large scale, eventually reaching the gigatonne/year scale globally. Establishing sequestration as a practical large-scale activity requires work across the board, including science, technology, infrastructure design, regulation and international standards. None of the key technical and public acceptance issues have been addressed with sufficient intensity. The program is characterized instead by small projects, many performers (e.g., the regional partnerships), and conversations that may have the virtue of involving many constituencies, but does not grapple with answers to the hard questions.

FUTUREGEN Given its central role in the DOE program, we comment specifically on the FutureGen project. We support the concept of an integrated demonstration of IGCC+CCS; however, we have several concerns about this particular project structure.

First, there is continuing lack of clarity about the project objectives. Indeed, the DOE and consortium insist that FutureGen is a research project and not a demonstration project. This distinction appears to be motivated by the fact that higher cost sharing is required for a demonstration project, typically 50% or more from the private sector. However, the main purpose
of the project should be to demonstrate commercial viability of coal-based power generation with CCS; it would be difficult to justify a project of this scale as a research project. And it would probably be unwise.

The ambiguity about objectives leads to confusion and incorporation of features extraneous for commercial demonstration of a power plant with CCS, and to different goals for different players (even within the consortium, let alone between the consortium and the DOE, Congress, regulators, and others). Second, inclusion of international partners can provide some cost-sharing but can further muddle the objectives; for example, is Indian high-ash coal to be used at some point? This effort to satisfy all constituencies runs the risk of undermining the central commercial demonstration objective, at a project scale that will not provide an agile research environment.

Congress and the administration should declare FutureGen to be a demonstration project, decide what level of cost sharing is appropriate to the risk without adherence to an arbitrary historical formula, and incorporate options for “experiments” only to the extent that they do not compromise the objective of commercial demonstration of the integrated system with proven components. The project design should be optimized by analysis of tradeoffs that an investor would require. FutureGen is a complex project; its success requires clarity of purpose.

It remains to be seen whether political realities will allow DOE and the FutureGen consortium the freedom to operate without the intrusion of federal procurement rules and government cost auditing. It is crucial that the sequestration program proposed in Chapter 4 not be dependent on progress of the FutureGen project. Of course, it is preferable that FutureGen, if built, support a proper sequestration demonstration. However, the sequestration projects must be accommodated with sufficiently reliable CO₂ supply to multiple sites, with the choice of sites optimized to provide the public with a benchmark for implementation of large-scale sequestration.

THE RECOMMENDED ARD&D PROGRAM

Our principal objectives in this chapter are to recommend a federally-supported coal analysis, research and development program based on the analysis in Chapters 3 and 4 and aligned with the strategic goals of enabling large-scale coal use in a carbon-constrained world and to discuss criteria for federal support of large-scale integrated demonstration projects with CCS.

ANALYSIS AND SIMULATION.

Powerful engineering-economic simulation tools are needed for analysis of integrated coal combustion and conversion systems, with CCS, under a variety of system configurations and operating conditions. This should be a very high priority in the DOE research program.

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We estimate $50M/year is needed to support a strong program.
PC POWER GENERATION R&D

With the very large PC fleet in place (~325 GWₑ in the U.S.) and the expected additions to this fleet over the next two decades, the possibility of imposition of a significant carbon emission charge indicates the need both for ultra-high efficiency and for much less costly CO₂ capture technology for PC combustion plants. Success in both could dramatically alter the relative cost of PC and IGCC with capture. The higher efficiency gains will come from operating at higher steam pressures and temperatures and thus require developing higher-strength corrosion-resistant materials and advanced fabrication technologies.

Reducing capture cost appreciably is especially important for PC plant retrofits; this calls for an integrated research effort starting with CO₂ chemistry and physical properties, combined with a theoretical and experimental program focused on designing (or identifying) absorbents or adsorbents that can effectively capture CO₂ and then release it with a much lower energy requirement than present solutions. Other approaches, beyond absorbents and adsorbents, should also be explored in a basic science program.

Oxy-fuel coal combustion appears to offer significant potential for new plants or retrofit CO₂ capture applications and is moving towards demonstration with a pilot plant under construction in Germany (30 MWₑ) by Vattenfall. If successful, Vattenfall intends to build a 300-600 MW demonstration plant. SaskPower (Canada) has also announced its intention to build a 300 MW oxy-fuel power plant. Basic research to develop less costly oxygen separation technologies is a high priority, one that will also lower the cost of gasification systems. One attractive possibility for oxy-fuel combustion is to compress the entire flue gas stream (minus the water, which is relatively easy to remove) to CO₂ supercritical conditions, assuming the entire stream could be transported and injected as-is into a geologic formation. Much research is needed on the compositional requirements for pipeline transport as well as for injection into geologic formations, on process design and evaluation studies, and on process development units.

Thus, key elements of a PC power generation R&D program include:

- An R&D program to develop the next level of high-strength materials along with cost-effective fabrication technologies for ultra-supercritical (USC) PC operation beyond the current USC conditions (> 1250 °F). This effort should build on the European and Japanese USC programs and current U.S. efforts.
- A significantly increased, broadly-based, coordinated R&D program on CO₂ capture and recovery systems, aimed at developing more cost effective and energy efficient CO₂ capture systems.
- An integrated design and PDU program on oxy-fuel combustion, coordinated with related activities in Europe, Canada, and Australia, including oxygen separations research and a focused effort to understand the impact that other components in the supercritical CO₂, such as SO₂, could have on the geologic formations into which they are injected and on injectivity.
- A program to evaluate (via focused design studies) and provide data specific to oxy-fuel PC retrofit technology should be initiated. A retrofit demonstration could offer an opportunity to produce CO₂ for a major sequestration demonstration (as discussed below).

We estimate $100M/year as appropriate for this program.

IGCC POWER GENERATION R&D.

IGCC presents a different set of issues from PC generation because IGCC currently appears to offer, at least for high rank coals, the lowest COE with CO₂ capture if efficiency and availability are high. Availability centers on the gasifier, on turbine operation with hydro-
gen-rich gas, and on integrated operation of the IGCC power plant with capture. Unlike PC generation where the basic boiler design is relatively homogeneous, gasifier designs are quite heterogeneous with 5 to 10 major types that could eventually become commercial. Some key elements required for a gasification R&D program are:

- Pressing the limits of syngas clean-up to reduce emissions to very low levels could help gain acceptance for IGCC without and with capture.
- Development of turbines for hydrogen-rich syngas is particularly important to the success of IGCC with CO₂ capture.
- Improved coal injection technologies, refractory improvement or elimination, and instrumentation developments to facilitate operational analysis and control will enhance availability.
- Research into the processing in gasifiers of widely different coal types, including sub-bituminous coals and lignites, should be evaluated aggressively. This should include basic research for novel concepts and PDU-scale evaluation of promising technologies, combined with rigorous simulation and economic analysis. Advanced power cycles with high efficiency potential are an area of interest.
- System integration studies of electricity production with fuels, chemicals, and/or hydrogen production, with CCS, should go forward, initially through simulation.
- Basic research and PDU-level studies of syngas conversion should be supported more strongly.
- Research on advanced technology concepts related to IGCC should be expanded.

We estimate $100–125M/year as supporting a strong program.

**CO₂ SEQUESTRATION RD&D**

The priority needs for a sequestration R&D program are discussed in detail in Chapter 4. Because of the close integration of research and demonstration in the case of sequestration RD&D, these will be considered together. The key elements identified in Chapter 4 were:

- Detailed, “bottom-up” geological assessments of storage capacity and potential for injection rates. This should also include a risk analysis of potential geologic storage regions.
- An expanded and accelerated R&D program that includes simulation, testing, and integration of MMV technologies that should be employed in major geologic sequestration demonstrations and in commercial storage programs.
- Development of protocols and regulatory structures for the selection and operation of CO₂ sequestration sites and for their eventual transfer of liability to the government after a period of good practices is demonstrated. We stress the urgency of research in these areas, including development of viable options for setting international standards and monitoring mechanisms.
- Several large-scale injections within key plays and basins of the U.S. These need to be of the order of 1 million tons CO₂/year over several years with a substantial suite of MMV technologies employed to enable a quantitative understanding of what is happening and to identify the MMV tools that will be most effective in commercial operation. These will need major sources of CO₂. To maximize effectiveness of the sequestration studies, sources for the first projects should be “on demand” sources to the extent practical (i.e., if appropriately sized and located), such as natural sources, industrial by-products (e.g., from natural gas processing plants or refineries), or CO₂ captured from a flue gas slip stream at a large operating coal PC plant. Subsequently, the CO₂ source could be purchased from a demonstration plant that advances the knowledge base for advanced coal technologies with capture.