CLEAN AIR TASK FORCE

Coal Without Carbon

An Investment Plan for Federal Action

EXPERT REPORTS ON RESEARCH, DEVELOPMENT, AND
DEMONSTRATION FOR AFFORDABLE CARBON CAPTURE AND SEQUESTRATION

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COVER IMAGE:
Synthesis gas production well at Carbon Energy Ltd., underground coal gasification site in Queensland, Australia, November, 2008. Image by Mike Fowler, Clean Air Task Force.

Clean Air Task Force is a nonprofit organization dedicated to reducing atmospheric pollution through research, advocacy, and private sector collaboration.

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EXECUTIVE SUMMARY

There is widespread agreement that technologies for carbon capture and sequestration (CCS) from coal fired power plants are an essential tool to mitigate global climate change. While current technology can do the job, more efficient and less expensive CCS-related technologies would be highly beneficial.

This study examines several technologies for CCS that are not currently receiving adequate development support but that could — in the right policy environment — provide the kind of significant cost reductions (and significant improvements in efficiency) that could greatly accelerate broad, economically attractive CCS deployment.[1] Several gasification technologies that "enable" CCS by reducing overall energy systems costs and improving efficiency also play a prominent role in this report. The most significant of these may be gasification of coal directly in wet seams deep underground so that a gaseous fuel can be extracted.

Clean Air Task Force selected these technology areas (though not the technologies themselves) and solicited reports from experts in each field to explore how these technologies might fit into a broader CCS deployment strategy. Each expert was asked to develop a research, development, and demonstration (RD&D) "road map" that could efficiently move each technology from the laboratory into the commercial mainstream. Because the chapter authors are either technical experts or commercial players and are not, for the most part, energy policy experts, subsequent work will translate their RD&D recommendations into actionable policy proposals.

The heart of this report consists of four chapters on advanced coal and CCS technologies:

- Underground coal gasification (UCG), written by Julio Friedmann at Lawrence Livermore National Laboratory;
- Next generation coal gasification (surface-based gasification) led by Eric Redman at Summit Power Group;
- Advanced technologies for post-combustion capture (PCC) of CO2, led by Howard Herzog at Massachusetts Institute of Technology; and
- RD&D to speed commercialization of geological CO2 sequestration (GCS), led by Julio Friedmann.

Each chapter has been written as much for other experts in the field as for policy makers. Still, an effort has been made to make the information accessible. Summaries of each chapter and its RD&D recommendations are included below.

Underground Coal Gasification

Underground coal gasification (UCG) is a promising technology in which coal is converted into a gas deep within a coal seam by the controlled injection of air or oxygen (and sometimes steam). Experience has shown that the resulting gas has less sulfur, nitrogen, and ash than the gasified coal and contains high levels of hydrogen, which makes it well-suited for use as fuel for a power plant designed for low CO2 emissions. The gas is brought to the surface in wells similar to the wells used to produce natural gas. Specific advantages of UCG include:

- UCG has the potential to enable electricity generation from coal, with CO2 capture, at costs that are far lower than IGCC and conventional coal with similar levels of capture. This is largely due to the relatively low costs of producing and cleaning the gas.
- UCG offers the potential to reduce the lifecycle environmental impacts of coal use by avoiding damaging mining and coal transportation activities.
- UCG will work well with lower-grade coals, making it attractive in places like India where coal

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[1] Other potentially important CCS technologies, such as direct capture of carbon dioxide from ambient air, are outside the scope of this report.

quality is generally poor and use of CCS may be constrained by the high costs of imported coal.

- Resources suitable for UCG are found in many areas of the world where coal utilization is large and growing (for example, the Powder River Basin in Wyoming, the Illinois Basin of the Midwest United States, China, and India).

Commercial interest in UCG has been growing in recent years, with several pilot projects operating or under development around the world, especially in China, Australia and South Africa. Additional projects are on the drawing board in the United States (especially in Wyoming) and in Canada. These projects are primarily based on knowledge developed in early research programs in the United States and the former Soviet Union and it is clear that substantial improvements in project siting and operation can be achieved. Such improvements are likely to reduce UCG costs and more effectively address the environmental risks sometimes associated with UCG (in particular, groundwater contamination resulting from improper operation). At the same time, the potential benefits of UCG for CCS are not particularly well understood at present due to limited experience.

The potential advantages of UCG technology, the environmental risks of improper operation, and nascent commercial activity all warrant real federal investment in building new knowledge about UCG. Today, however, federal investment in UCG RD&D is essentially nonexistent. Therefore, to build knowledge for effectively deploying UCG, we recommend a four year, $122 million RD&D effort, led by the federal government in conjunction with commercial enterprises. Important facets of this effort, which are detailed in Chapter 1, include:

- Improved fundamental understanding of UCG processes and interactions with the subsurface environment, including simulation technology, monitoring technology, and fit-for-purpose CO2 capture and sequestration technology.
- Development of a targeted UCG field program, which would include:
    - Technical support for and collaboration with early commercial projects;
    - Funding and management of a dedicated domestic state-of-the-art UCG research and training facility; and,
    - Support for and collaboration with international field activities.
- Rapid development of human capital on UCG, including university programs, technical workshops, and project-based experience.

Next Generation Coal Gasification

Current gasification systems such as those used in the integrated gasification combined cycle (IGCC) power plants in Polk County, Florida and Wabash, Indiana offer some advantages for CCS over conventional coal combustion power plants. These gasification systems also face some challenges to deployment, however, especially capital costs and internal power requirements. Fortunately, gasification technologies have been the subject of considerable R&D over the past several decades, and a number of promising new technologies have been developed which could — with early deployment support — lead to significant reductions in cost, and improvements in efficiency, over the existing technologies.

Chapter 2 of this study examines a handful of these advanced or “next generation” gasification technologies. Included in the review are:

- Bluegas from Great Point Energy (a method for catalytic coal gasification and production of substitute natural gas — SNG);
- The Calderon Process from Energy Independence of America Corporation (a gasification process based on coking and blast furnace technology in the steel industry);
- The Viresco Process (based on hydrogasification);
- High Temperature Hydrogasificaton from ThermoGen Hague (a technology based on gasification using very high temperature steam);
- HydroMax from Alchemix (a molten bath gasification technology);
- Wiley Process from SynGasCo (a non-catalytic syngas reforming technology);
- Ze-gen Process (a molten bath gasification technology).

Demonstrating these technologies at sufficient scale to provide a basis for further, fully commercial deployment, has been a great challenge to technology developers working in this area. Accordingly, our key recommendation for this class of technologies generally is a “first commercial project fund" that would have the following general attributes:

- The fund would be a public-private partnership with a strong technology assessment capability.
- The fund would provide keystone financing, particularly debt support, for risky first commercial-scale projects.
- The fund would be self-sustaining following an initial public investment, by spreading risk across an investment portfolio, participating in upside gains for successful technologies, and engaging private sector participation with tailored investment products.

We envision an initial federal investment of several billion dollars for this fund, with details to be determined during program implementation. In addition, our review suggests a need for continued and expanded federal R&D in gasification technologies at sub-commercial scale. We therefore recommend a five-year, $250 million expansion of federal gasification R&D, which would include provision of process analysis and modeling support to technology developers and construction of one or more shared user facilities for testing new gasification technologies.

Advanced Post-Combustion Capture

Technology for removal of CO_2 from the exhaust stack of a coal power plant is available today and it will be a critical technology for reducing emissions from the massive existing installed base of coal power plants worldwide, especially in China where many plants are relatively new and can't be expected to retire any time soon. In fact, post-combustion capture (PCC) may offer one of the fastest ways to reduce global CO_2 emissions, because of the size and relative uniformity of the large and rapidly growing coal power generation emissions pool. It is also clear that absent application of PCC to most of the rapidly expanding coal power plant "fleet", it will be impossible to meet mid-century CO_2 reduction targets. Unfortunately, today's post-combustion capture technologies have not yet been deployed at full scale on coal power plants, as the resulting significant reductions in generation output and coal consumption per unit of electricity generated — which substantially increase power costs — are significant hurdles to deployment.

There are a number of advanced technologies that could significantly reduce the "efficiency penalty" of PCC. As detailed in Chapter 3, these include:

- Advanced amine solvents and solvent systems
- Amines immobilized within solid sorbents
- Polymeric membrane absorbents
- Metal organic frameworks
- Structured fluid absorbents (CO_2 hydrates, liquid crystals, and ionic liquids)
- Non-thermal solvent regeneration methods, including electrical and electrochemical approaches

In order to explore these novel approaches at laboratory scale while also demonstrating viable technologies at sub-commercial and commercial scale, we recommend establishing an RD&D "pipeline" mechanism that would have the following attributes:

- An initial survey of performance characteristics of the US coal power fleet
- An 8-10 year funding timeframe, commencing immediately
- Funding for 50 exploratory research efforts at laboratory scale (roughly $1 million each)
- Funding for 30 proof of concept efforts for technologies that meet screening criteria (roughly $10 million each)
- Funding for 15 pilots plants (roughly $50 million each) for viable technologies
- Funding for five commercial-scale demonstrations, including some of today's leading technologies and more advanced technologies that have come up through the pipeline (roughly $750 million per project)

The total expenditure for this effort would be roughly $6 billion.

Deployment of Geological Sequestration

Geological sequestration of CO_2 (GCS) in saline aquifers is neither the most expensive nor the most energy intensive part of an integrated CCS process (far from it), but it is the aspect currently subject to the highest levels of regulatory and public scrutiny and the aspect of CCS most dependent on site-specific characterizations of long-term environmental processes. Although early-mover integrated CCS projects will look to commercial enhanced oil recovery (EOR) operations for sequestration, the ultimate capacity of that resource will be limited. Therefore robust technical knowledge and decision-making frameworks for geological sequestration — especially in saline formations — should be accessible to many diverse stakeholders (including the general public, regulators, investors, and other parties to commercial transactions) prior to widespread deployment. As a market for CO2 sequestration emerges and the GCS industry matures, private companies will likely take on much of the technology development burden. In the near term, however, a targeted public technology development program will reduce the risk and cost of GCS commercialization.

In order to accelerate dissemination of the required "learning by doing" we recommend a targeted RD&D program for geological CO2 sequestration that has the following components:

- A comprehensive research and development program focused on the most pressing issues that relate to risk and cost reduction, including:
  - Hazard assessment/risk management (groundwater protection, geomechanics, well bores);
  - Monitoring and verification (novel tools, integration, lab work);
  - Applied science and technology (advanced simulators, basic science).
- A field demonstration program where field knowledge and iteration can improve the speed of learning and reduce the cycle time for development including:
  - Enhanced U.S. program — Seven projects injecting between 1 million and 5 million tons of CO2 per year, including some projects emphasizing integration with upstream processes;
  - Experimental test bed to support rapid R&D — A dedicated domestic facility where repeated, iterative experiments are used to build core knowledge.
- A program of international cooperation focused on accelerating knowledge development and technology transfer to rapidly developing countries such as China and India including:
  - Field program — US involvement in eight international projects over a range of economic and geologic conditions;
  - Non-technical work — Participate in knowledge sharing efforts related to permitting requirements, regulatory structure, subsurface ownership and access, and long-term liability;
  - Geologic assessments — Partner with other key nations and provide staff, sponsorship, and knowledge in support of regional and national geological assessments.

The total expenditure for implementing these recommendations is estimated at $3.2 billion over four years. ■

INTRODUCTION: COAL WITHOUT CARBON

The Imperative for Low-Carbon Coal

JOHN THOMPSON AND **MIKE FOWLER,** CLEAN AIR TASK FORCE

Global warming is already occurring. Since the start of the Industrial Revolution, more than 1,500 *billion* tons of the greenhouse gas carbon dioxide (CO2) have been released by human activity. CO2 concentrations in the atmosphere have now reached 385 parts per million (ppmv) — a 35 percent increase over pre-industrial levels. During the same period, these emissions have already increased global temperature by about 0.8°C. Because carbon dioxide has such a long atmospheric lifetime, global temperatures could rise an additional 1.8°C due to the CO2 already released if emissions stopped completely today.[1] And for each ton of CO2 emitted today, close to half a ton could still be airborne one thousand years from now, contributing to damaging temperature increases that last for millennia (Mathews and Caldeira, 2008; Solomon *et al*, 2009). Given our best projections, the impacts of sustained, elevated global temperature on human society could potentially be greater than recorded recessions, depressions, or global wars.[2]

Coal is a major source of CO2. It accounts for more than 40 percent of all energy system CO2 emissions worldwide. And because it is relatively cheap and abundant, especially in industrialized areas of the world, it is unrealistic to think that coal will "go away." China has recently been building new coal power plants at an astounding rate, adding as much capacity in the past several years as the entire U.S. coal power fleet (just over 300 GW[3]), which took sixty years to build (Cohen *et al*, 2009). India is also poised to develop large amounts of new coal generation capacity. The International Energy Agency currently projects that world coal capacity will nearly double by 2030, an increase of 1,310 GW — of which China and India will account for 883 GW and 241 GW respectively (IEA,2008). If this generation expansion occurs with conventional coal technology, world CO2 emissions will grow by about 12.6 billion metric tons annually by 2030, or roughly twice today's CO2 emissions from all U.S. sources (IEA, 2008).

Against this backdrop of rising CO2 emissions from coal, science is suggesting that CO2 reductions may need to occur faster and deeper than first thought. As recently as a few years ago, aggressive targets of 50 percent reduction in global CO2 emissions by mid-century were suggested to avoid the worst impacts of climate change. But with more thinking about warming feedbacks, the role of the oceans in temperature control and carbon cycling, and aerosol masking, a 100 percent reduction — or even net negative emissions[4] — by mid-century may be required. Mathews and Caldeira — two leading climate scientists — put it this way in the title to a 2008 paper: "Stabilizing climate requires *near-zero* emissions" (emphasis added).

No one technology can achieve all the reductions needed to avert the worst impacts of climate change. Energy efficiency, renewable energy, and nuclear power are essential for deep CO2 emissions reductions, but cannot do the whole job. To meet even modest CO2 emissions reduction targets, a recent study suggests that CO2 emissions from energy systems must decrease by almost 10 percent per year for the next several decades (Anderson and Bows, 2008). This reduction rate greatly exceeds the one-time, short-lived CO2 emissions reductions due to the collapse of the former So-

[1] Further temperature increases due to past CO_2 emissions may occur due to the climatic inertia of the oceans, on-going efforts to reduce emissions of toxic aerosol compounds (which mask the effects of global warming), and slow feedback cycles in the climate system (for example, ice mass and vegetation pattern changes). See, for example, Ramanathan and Feng (2008) and Hansen *et al* (2008).

[2] The Stern Review (2006) likens the impacts of warming scenarios less extreme than are currently forecast by some models to the depression and world wars of the early 20th century. But unlike sustained temperature increases, those were relatively brief events.

[3] One gigawatt (GW) is one billion watts.

[4] To be accomplished by direct removal and sequestration of atmospheric CO_2.

viet Union's economy, the 25-year build of new nuclear power plants in France, or the United Kingdom's "dash to gas" power in the 1990s (Anderson and Bows, 2008; also Stern, 2006). No single technology or policy is capable of achieving such "modest" reductions, much less the emerging target of zeroing out global CO2 emissions by 2050.

Carbon capture and sequestration (CCS) technologies hold special promise for reducing CO2 emissions from coal and other fossil fuels. CCS technologies separate CO2 before it can be emitted, and inject the CO2 deep underground, where it cannot affect the climate. Almost without exception, no credible technical body has found that adequate CO2 emissions reductions are possible without widespread use of CCS (CATF, 2008). But scale-up of this technology to the level needed to help solve global warming faces several challenges. CCS is technically feasible today and deployment potential is vast: the Intergovernmental Panel on Climate Change (2005) has estimated that capacity exists to geologically sequester hundreds of years of global CO2 emissions. Only a handful of large-scale CCS systems are operating today, however. Components of an electric power generation system with CCS have not yet been integrated and operated at large scale. And CCS is costly, like many other CO2 emissions mitigation options. Applying CCS to a new pulverized coal power plant today might increase the costs of electricity generation by 80 percent while requiring as much as 40 percent more coal fuel compared to operation without CCS. For power plants based on gasification technology these increases are less pronounced but still significant (DOE/NETL, 2007). Less than a quarter of these costs are for underground CO2 sequestration. Most costs are for equipment to separate and compress CO2 at the power plant itself.

This report describes a research, development, and demonstration (RD&D) path to significant CCS technology improvements and associated cost reductions. (See Box I.1 for a general description of RD&D terminology). Three chapters address CO2 capture and enabling technology: underground coal gasification, advanced surface coal gasification and advanced post-combustion CO2 capture. The fourth chapter addresses geologic carbon sequestration. These technology areas were selected because they could lower the cost and accelerate widespread deployment of CCS and because they are not being adequately or sufficiently addressed by existing RD&D programs in the United States or elsewhere.

Energy technology innovation is a complex process involving diverse participants, large investments, and long time horizons (CSPO/CATF, 2009). And increasingly, this innovation system is truly international, with participants, technology, and policy developed and shaped with global feedbacks.[5] Thus, any effective RD&D program must link with relevant researchers and capabilities in other countries conducting related technology RD&D such as China, Australia, and Japan to facilitate rapid, cost-effective and widespread deployment of CCS technology. This is especially important given that the majority of CCS deployment must occur in countries like China and India to have any hope of meeting mid-century CO2 emission reduction targets. To be successful, execution of this report's RD&D recommendations must be conducted in real and effective cooperation with other key countries.

Clean Air Task Force hopes that this report serves as a guide for action to reduce costs of CCS technologies. Along the way we have greatly benefited from the expertise and efforts of many whose input is not acknowledged directly in this report.

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[5] China Huaneng Group and Duke Energy in the U.S. are collaborating on several areas of energy technology innovation, for example, Huaneng Group has post-combustion capture experience developed in partnership with Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO).

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Box I.1

Description of Research, Development, Demonstration, and Commercialization

Research, often subdivided in basic (or fundamental) research and applied research, aims to generate and validate new scientific and technical knowledge — whether in physics, in chemical engineering, or in organizational behavior. Development refers to a broad swath of activities that turn knowledge into applications. Generally speaking, development differs from research in being a matter of synthesis — envisioning and creating something new — rather than analysis in search of understanding. Design and development, the core activities of technical practice and hence the source of much technological innovation, apply knowledge in forms such as technical analysis based on mathematical models and methods. These can be used, for instance, to predict how PCC processes will scale up to larger sizes and for estimating their energy consumption. Over the past several decades, computer-based modeling and simulation have complemented and sometimes substituted for costly and time-consuming testing of prototypes. Demonstration is a particular type of development activity intended to narrow or resolve both technical and business uncertainties, as by validating design parameters and providing a sound basis for cost estimates. Demonstration has considerable importance for some energy-climate innovations, notably carbon capture and storage. (Accounting and budgeting conventions normally treat demonstration as a form of R&D.) Commercialization, finally, marks the introduction into economic transactions of goods or services embodying whatever is novel in an innovation. Commercialization does not imply widespread adoption, which, if it does occur, may still take decades. The definitions of R&D used by the National Science Foundation in compiling its survey-based estimates have become widely accepted; they appear for instance, on pp. 4-9 of Science and Engineering Indicators 2008, Vol. 1 (Arlington, VA: National Science Board/National Science Foundation, January 2008). ■

Source: Excerpted from CSPO/CATF (2009).

Glossary of Acronym Definitions

AA	Aqueous Ammonia
ACESA	American Clean Energy and Security Act
AERI	Alberta Energy Research Institute
AGTSR	Advanced Gas Turbine Systems Research
ARRA	American Recovery and Reinvestment Act
ASU	Air Separation Unit
BGL	British Gas/Lurgi
BP	British Petroleum
CAP	Chilled Ammonia Process
CATF	Clean Air Task Force
CCGT	Combined Cycle Gas Turbine
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture and Sequestration
CCTDP	U.S. Clean Coal Technology Demonstration Program
CE-CERT	College of Engineering – Center for Environmental Research and Technology at University of California, Riverside
CMG	Control Moment Gyros
CO2	Carbon Dioxide
CRADA	Cooperative Research and Development Agreement
CRIP	Controlled Retracting Injection Point
CSIRO	Commonwealth Scientific and Industrial Research Organization
CSLF	Carbon Sequestration Leadership Forum
CSPO	Consortium for Science, Policy, and Outcomes
CUMT	Chinese University of Mining Technology
DME	Dimethyl Ether
DOE	Department of Energy (US)
ECUST	East China University of Science and Technology
EIAC	Energy Independence of America Corporation
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
ERT	Electrical Resistance Tomography
FERC	Federal Energy Regulatory Committee
G8	Group of 8 industrialized Nations
GCCSI	Global CCS Institute
GCS	Geologic CO2 Sequestration
GE	General Electric
GHGT-9	9th International Conference on Greenhouse Gas Control Technologies
GRI	Gas Research Institute
GW	Gigawatt
HTHG	High Temperature Hydrogasification
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IIT	Indian Institute of Technology
InSAR	Interference Synthetic Aperture Radar
IPCC	Intergovernmental Panel on Climate Change
KBR	Kellogg, Brown, and Root
LANL	Los Alamos National Laboratory
LBNL	Lawrence Berkeley National Laboratory
LLNL	Lawrence Livermore National Laboratory
LTGI	Louisiana Gasification Technology, Inc.
M&V	Monitoring and Verification
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MIT	Massachusetts Institute of Technology
MOF	Metal Organic Framework
NETL	National Energy Technology Laboratory
ONGC	Oil and Natural Gas Company of India
OPEC	Organization of Petroleum Exporting Countries
OPIC	Overseas Private Investment Corporation
PCC	Post-Combustion Capture
PDU	Process Development Unit
PNNL	Pacific Northwest National Laboratory
pph	Pounds per Hour
ppmv	Parts per Million by Volume
PSDF	Power Systems Development Facility
PZ	Piperazine
R&D	Research and Development
RAM	Reliability, Availability, and Maintainability
RD&D	Research, Development, and Demonstration
RMI	"Rocky Mountain 1" UCG Project
RZCS	Reactor Zone Carbon Sequestration
SCPC	Super-critical, Pulverized Coal
SES	Synthesis Energy Systems
SNG	Substitute Natural Gas
THF	Tetrahydrofuran
tpd	Tons per Day
TPRI	Thermal Power Research Institute (China)
TRIG	Transport Reactor Integrated Gasifier
UCG	Underground Coal Gasification
VOC	Volatile Organic Compounds
VSP	Vertical Seismic Profiling
WRI	World Resources Institute
ZIF	Zeolitic Inidazolate Frameworks

CHAPTER 1

Accelerating Development of Underground Coal Gasification:

Priorities and Challenges for U.S. Research and Development

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In recent years, the search for solutions to the world's energy-climate predicament has led to growing interest in "clean coal" technologies. Underground coal gasification or UCG offers a promising method of increasing the availability of coal as an energy resource, while substantially reducing the pollution and greenhouse gas emissions associated with coal use. Through a process of partial oxidation and reaction with high temperature steam, UCG converts coal below ground (*in-situ*) into a synthesis gas or "syngas", which in turn provides a potential source of power for electricity or a feedstock for the production of chemicals, liquid fuels, hydrogen and synthetic natural gas.

While research into UCG peaked in the United States in the 1970s and 80s (largely in response to the OPEC oil embargo and rising oil prices), the technology has gained new attention over the past decade as concerns over global warming and energy security have intensified. With worldwide coal consumption currently at 27 percent of total energy use and projected to increase by nearly 50 percent over the next 20 years (US DOE, 2009), the need for cost-effective, near-term measures to mitigate coal's environmental impact has become urgent. UCG not only allows for control of pollutants, such as sulfur, nitrous oxides, and mercury emissions, in a manner similar to surface gasifiers; it is also potentially the lowest cost path to carbon capture and storage (CCS) for coal (NorthBridge Group, 2009). The well infrastructure for UCG offers possibilities for geologic CO2 storage that may reduce some of the capital and operating expenses associated with above ground gasification. At the same time, UCG has the potential to increase recoverable coal reserves in the United States by 300 to 400 percent by enabling gasification of otherwise unmineable deep or thin coal seams in diverse geological settings.

The enormous potential of UCG to meet rising energy demand in a CO2 constrained world warrants a high-priority effort by the United States government to speed commercialization of UCG on a large scale. Recent trials of UCG in a number of countries suggest that while the technology is close to commercial readiness, a number of key hurdles remain. Better predictive science is needed to assure stakeholders of the technology's safety, reliability and repeatability in a range of settings. Operators of the few commercial facilities currently in existence have not yet compiled and disseminated a comprehensive body of technological information, nor have they attempted carbon management — steps that are necessary for the wide deployment of UCG.

This chapter describes the components of a US program that would enable UCG to advance from an experimental technology to a widely available energy resource over the next five to ten years. Five critical objectives for research and development are addressed:

1. **Filling the Gaps in UCG Technology** — by addressing persistent technical questions through improvements in basic science research, simulation techniques, monitoring and verification methods, and module design
2. **Advancing Carbon Capture and Sequestration (CCS)** — by pursuing research into CCS pathways in the context of UCG
3. **Ensuring Environmental Management** — by improving control of environmental risks associated with UCG
4. **Increasing Human Capital** — by addressing the shortage of UCG expertise in the US through expansion of academic and practical training
5. **Establishing a Targeted Field Program** — by funding a number of pilot projects, creating one state-of-the art facility for training and testing, and directly engaging with international initiatives

The discussion identifies many of the lessons learned from specific trials around the world and charts a course for the development of a UCG industry in the United States, based on close collaboration between federal efforts and nascent commercial enterprises — both those at home and abroad.

FIGURE 1

Bloodwood Creek UCG site, Queensland, Australia, November 2008

The view is from the vicinity of the subsurface reactor (active at ~200m depth) towards the production well (far distance).

Courtesy of M. Fowler, CATF.

I. Description of Underground Coal Gasification (UCG)

Gasification is a chemical process that allows for the conversion of a solid or liquid fuel into a combustible gas, which can subsequently be used to produce heat, generate power, or provide a feedstock for chemical products such as ammonia, methanol, synthetic natural gas, or liquid transportation fuels. Hundreds of surface gasification plants have been constructed around the world, and currently more than 160 coal gasification plants are in operation, producing the equivalent of more than 80,000 MW (thermal) of raw syngas.

UCG utilizes the same chemical reactions at work in surface gasifiers but moves the process underground. Air (or oxygen) is injected deep into the ground, where it causes partial oxidation of in-place coal. The oxidation produces heat which in turn drives the key gasification reactions producing a gas mixture made up chiefly of hydrogen (H2), carbon monoxide (CO), carbon dioxide (CO2), and some amounts of methane (CH4). Because UCG reactors operate below the water table, water enters the reactor during the reaction process. As the coal is gasified and syngas is brought to the surface, an empty cavity develops below ground. The eventual size of the cavity depends on the rate of water influx, the heat content of the coal, the location and shape of the injection and production wells, and the thickness of the coal seam. The UCG process relies on the natural permeability of the coal seam in order to transmit gases to and from the combustion zone. Directional drilling, as well as various techniques for developing linkages between wells, can enhance coal seam permeability.[1]

A number of factors affect the composition of UCG syngas including the choice of air or oxygen injection, the "rank" and composition of the coal (determined by burial pressure, heat and time), and the pressure and temperature of operation. While the make-up of UCG syngas tends to be similar to that of syngas produced by surface gasifiers, the influx of groundwater into the UCG reactor and other factors gives UCG syngas a relatively higher hydrogen concentration — a potential cost advantage when producing electricity.

The process of underground coal gasification avoids many of the environmental hazards associated with conventional coal use. Because no mining is involved, issues such as acid mine drainage and mine safety do not play a part, and land reclamation is minimized. Furthermore, during gasification, roughly half of the sulfur, mercury, arsenic, tar, ash, and particulates from the used coal remain in the subsurface, and any sulfur or metals that reach the surface arrive in a chemically reduced state, making them relatively simple to remove. These two effects allow for reduced

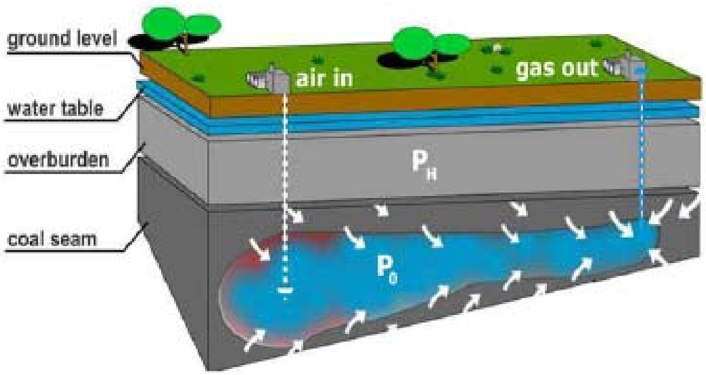
[1] These techniques include electro-linking, hydrofracturing, in-seam channel, and reverse combustion. See: "Best Practices in Underground Coal Gasification" (draft), Burton *et al.* (2006) (https://co2.llnl.gov/pdf/BestPracticesinUCG-draft.pdf).

FIGURE 2

Schematic Diagram Of A UCG Reactor

Note that the reactor is below the water table and that water flows into the cavity.

Courtesy of ErgoExergy



emissions of criteria pollutants. Additionally, because the process water for gasification comes primarily from the subsurface — and, in the most recent project sites, from saline formations at depth — less surface and shallow groundwater is required for power or fuel production. Finally, UCG may allow for the removal of CO2 from the syngas before use by means of established technologies at significantly reduced cost.[2]

Alongside these advantages, UCG presents a unique set of engineering and environmental challenges — most notably, the problems of surface subsidence (or caving) and groundwater contamination — that will be addressed in some detail below. The discussion turns first to an overview of UCG history in order to highlight past progress and setbacks in the technology's evolution and to clarify the current status of efforts aimed at advancing UCG's commercial viability.

II. The Evolution of UCG Technology

Over the past century, more than 50 attempts at underground coal gasification have taken place around the world, under diverse ecological and economic conditions and yielding varying levels of success. In 1868, a German scientist, Sir William Siemens, published the first paper proposing the idea of gasifying coal underground, but it was Soviet scientists who pioneered the application of UCG on a large scale. Lenin, and later Stalin, promoted the technology as a boon for socialist society because it would eliminate the need for hard mining labor. In 1928, the USSR launched a national research and development program in UCG, and by the 1950s the government had achieved commercial-scale production of syngas. The first design involved an underground gasification chamber built into the coal that required underground workers, but later designs relied on boreholes linked by either vertical wells and reverse-combustion linking or directional underground drilling. The UCG site at Angren, Uzbekistan proved most effective, and continues to have capacity to produce up to 18 billion cubic feet of syngas a year, providing fuel for boilers that generate electricity at the Angren power station.

The Soviets demonstrated that UCG could operate successfully in coals in a wide variety of geologic settings and in the complex and changing conditions created by a burning coal seam and collapsing cavity (Gregg, *et al.*, 1976). Yet despite the apparent success of the technology, Soviet UCG production peaked in the mid-1960s and steeply declined after the 1970s for reasons that remain unclear. One possibility is that the discovery of extensive natural gas deposits in Siberia siphoned off support for investment in UCG. UCG may also have become less economically competitive relative to natural gas. There is also some evidence that Soviet UCG technology delivered disappointing yields and that the government ignored the recommendations of their own technical experts, making minimal use of diagnostics and modeling (Burton, et. al., 2006).

As the Soviet UCG program slowed, efforts to apply the technology in the United States intensified. Between 1974 and 1989, the United States was the site of major research and deployment efforts in many areas of renewable and fossil energy, including UCG. The impact of the OPEC oil embargo and rising oil prices increased federal support for UCG research and development. Over a 15-year period, the U.S. conducted 33 UCG pilot projects located in Wyoming, Texas, Alabama, West Virginia and Washington; the Department of Energy (DOE) sponsored much of the research,

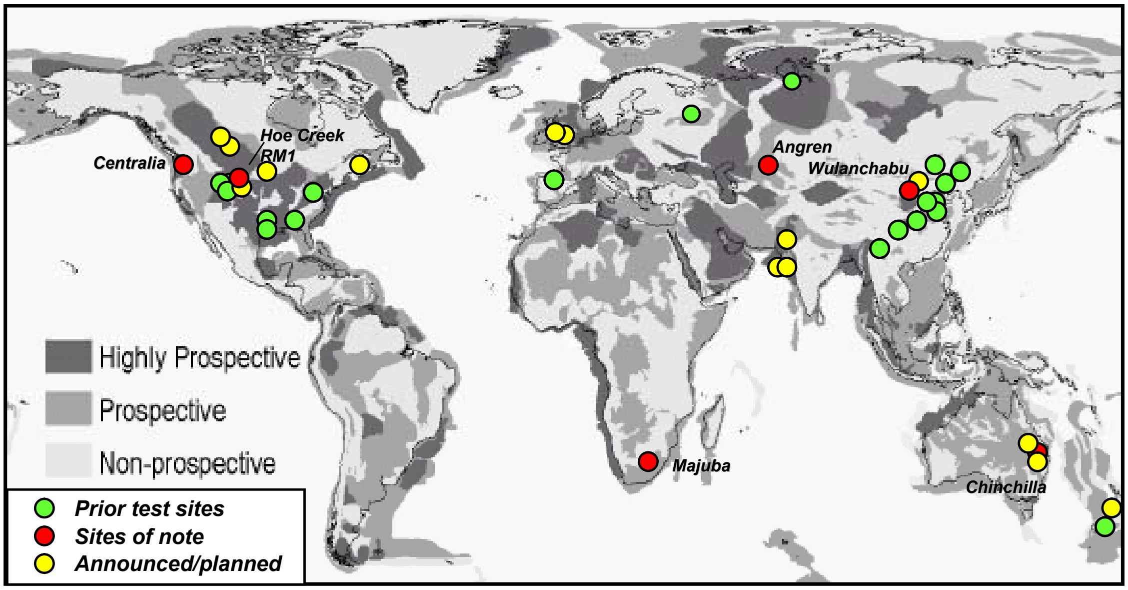
[2] Examples of gas removal technologies include Selexol and Rectisol.

FIGURE 3

Locations of Prior, Current, and Pending UCG Pilot Sites

Majuba, Bloodwood Creek, and Wulanchabu are active. The base map shows sequestration resource prospectivity.

(Bradshaw and Dance, 2004)



investing as much as $200 million in today's terms and the Lawrence Livermore National Laboratory was involved in at least half of the pilots.

The U.S. experiments in UCG succeeded in validating in-situ gasification as a process for recovering and converting low-rank coals, thick and thin seams, as well as seams that were flat or steeply dipping. The projects also yielded a number of technological advances — the most important of which was the introduction of "controlled retracting injection point" technology or "CRIP." CRIP allows for increased control over the gasification progress by enabling retraction of the injection point once the coal near the gasification cavity has been used up.[3] Other key technical developments included work on "reverse combustion linking" (a method for increasing coal seam permability) and "clean cavity" site closure methods.

The U.S. project sites also revealed evidence of some of the operational problems and environmental risks associated with UCG. Tests run in Hoe Creek, Wyoming in the late 1970s, for instance, revealed that water influx during the gasification process lowered the quality of the resulting gas; attempts to decrease water influx by increasing the operating pressure in the burn zone led to a significant amount of gas loss. More significantly, the Hoe Creek tests resulted in significant amounts of organic contaminants entering the groundwater, largely because the reactor was too shallow, was poorly operated, was not adequately separated from adjacent aquifers by a strong geologic "roof", and was designed as a first-of-a-kind experiment.

These discoveries informed the most successful UCG venture in the United States during the 1980s: the "Rocky Mountain 1" project or RMI was conducted in Carbon County, Wyoming, and jointly organized by the U.S. DOE, the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), Amoco Production Company, and Union Pacific Resources. The project tested both deviated CRIP and extended linked well process configurations over many weeks of continuous operation. It also incorporated environmental protection into planning and operational procedures. The project's organizers invested significant time and effort in site selection, characterization, process management, and post-project process and environmental evaluation.[4] A commercial follow-on project at the site, intended to produce ammonia from UCG syngas, won a first-round award in DOE's "clean coal" program. Unfortunately, the project never got off the ground, because after the 1986 drop in oil process, US support for UCG development effectively ended. The technology developments from RM1 have nevertheless provided a valuable basis for future commercial activity.

During the 1990s, European efforts at UCG led to a successful — though short-lived — trial in northeastern Spain. The tests run at the "El Tremedal" site in the Province of Teruel demon-

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[3] In the "CRIP" process, directional drilling is used to create a channel connecting the production well to the injection well. A gasification cavity forms at the end of the injection well in the horizontal section of the coal seam. Once the coal in the cavity area is expended the injection point is withdrawn (usually by burning a section of the liner) and a new gasifi-cation cavity is initiated (Burton, *et al.*, 2006).

[4] Dozens of academic papers and reports were written describing the work at RM1 and its implications for the science and technology of UCG (e.g., Thorsness & Britten, 1989; Metzger, 1988; Cena, 1988; Boyson *et al.*, 1990; Daly *et al.*, 1989). In 2008-2009, the RM1 results served as a template for Carbon Energy in demonstrating an advance CRIP configuration at their Bloodwood Creek site near Dalby in Queensland, Australia.

strated the feasibility of gasification at depths greater than 500m, as well as the viability of directional drilling for well construction and intersection, and the benefits of a controllable injection and ignition point. The project ultimately failed when the reactor failed, but it nevertheless led the Department of Trade & Industry Technology in the United Kingdom to identify UCG as one of several potential future technologies for the development of the UK's large coal reserves.

Current and Pending UCG Projects

Over the past few years, the most active efforts to develop UCG have been concentrated in a handful of countries. China, Australia, and South Africa all have operative power or chemical plants that are fed by UCG syngas, while Canada and the United States have a number of projects in the planning stages.

China currently has the largest UCG program worldwide, having carried out 16 UCG pilots since 1991. The government's encouragement of diverse approaches to coal use has led several Chinese companies to pursue production and utilization of UCG syngas. The XinWen coal mining group in Shandong Province, for instance, has six reactors producing syngas for cooking and heating (Creedy and Garner, 2004), and a project in Shanxi Province uses UCG gas for the production of ammonia and hydrogen. ENN Group and its subsidiary, XinAo Gas, are developing a 20,000 ton-per-year methanol plant at the site of its UCG project, and have plans to establish an additional 30,000 ton-per-year methanol plant at a different location.[5]

The Australian Chinchilla project, located in Queensland, ran from 1997 to 2003 and gasified a total of 30,000 tons of brown coal. Chinchilla is the largest UCG project outside of the former Soviet Union, and it stands out for its successful siting, operation, and environmental management efforts.[6] The Australian national scientific laboratory system — the Commonwealth Scientific and Industrial Research Organization or CSIRO — has also advanced UCG technology by combining experience in the energy and extractive industries with CRIP and operations data from the RM1 project. CSIRO's work on UCG includes developing managed geophysical modeling approaches and advanced monitoring techniques. Currently, Carbon Energy Limited — a joint venture between CSIRO and the mineral exploration company, METEX — has a pilot underway. The Bloodwood Creek project uses a parallel CRIP configuration and is on track to be the first commercially operated unit to generate electricity for sale through the grid. Bloodwood Creek will also be the site of 1000 ton-per-day ammonia plant.[7]

In South Africa, the main power utility, Eskom, initiated a UCG pilot project in January 2007, with technology provided by the Canadian company Ergo Exergy. The pilot, located in Majuba, South Africa, has been burning continuously; since the summer of 2008, a 100-kilowatt reciprocating engine has been generating power from UCG syngas at this site. The results have been extremely positive. Eskom, along with the South African Ministry of Coal and the Ministry of Energy have announced plans to build a 2100-megawatt combined-cycle plant (that is, a plant using both combustion and steam turbines) to run entirely on UCG syngas. The current schedule targets 375-megawatt production by 2011 and full production between 2013 and 2015.[8]

A total of four projects are currently pending or have recently been announced in Canada and the United States. Significantly, all of these projects plan to deploy carbon capture and sequestration as an integral part of their business model and facility design. Two pilots are planned for sites in Alberta, Canada: one — a project of Laurus Energy and Ergo Exergy — will target relatively shallow coal seams, the other — launched by Swan Hills LLC with Synergia Polygen — is a deep seam project that has already received drill permits and resources from the Alberta Energy Research Institute (AERI). Both sites will likely produce a combination of power, heat, and hydrogen to sell to tar sand producers and upgraders near Edmonton. In the United States, drilling for characterization is slated to begin this year; one is a Laurus Energy/Ergo Exergy pilot, the other is a joint venture between GasTech and BP. Both will be located in Wyoming.[9] Other US projects, in earlier stages of planning, will likely be announced over the coming year.

In addition to the projects summarized in Table 1, several developing countries have begun efforts to develop UCG. The Indian government issued a ruling in late 2007 that separates mining estates from UCG and coal-bed methane operations. Since

[5] China's University of Mining and Technology in Beijing has also received substantial government support to conduct *in-situ* gasification in abandoned coalmines.

[6] Ergo Exergy Technologies Inc. of Canada provided UCG technology for the project, which is now managed independently by Linc Energy. ENN's project in Wulanchabu may have recently surpassed Chinchilla in total mass of coal gasified.

[7] In addition to the Chinchilla and Bloodwood Creek projects in Australia, Cougar Energy and Solid Energy are about to launch pilot projects, in Queensland, Australia and New Zealand respectively.

[8] In addition to Eskom, the South African company, Sasol – the world's largest producer of motor fuels from coal – has announced plans for a UCG pilot to begin in September 2009.

[9] It is worth noting that Linc Energy of Australia has announced plans to purchase GasTech from its parent company, Wold Petroleum. This may complicate project progress.

TABLE 1 **UCG Pilots and Projects Begun in the Last 10 Years**

Country	Company	Pilot Name	Date of Run	Expected Product
Australia	Linc	Chinchilla*	Dec. 1999 – June 2002	Liquid fuels
Australia	Carbon Energy	Bloodwood Creek	Sept. 2008 – pres.	Power/Ammonia
Australia	Cougar	Kingaroy*	Not yet begun	Power
Canada	Laurus	TBD*	Not yet begun	Polygen
Canada	Swan Hills	TBD	Not yet begun	Polygen
China	ENN	Wulanchabu	Oct. 2007 – pres	Methanol
China	ENN	Tongliao	Not yet begun	Methanol
New Zealand	Solid Energy	Huntley*	Not yet begun	Power
S. Africa	Eskom	Majuba*	Jan. 2007	Power
S. Africa	Sasol	TBD	Not yet begun	Liquid fuels
United States	GasTech	TBD*	Not yet begun	Unknown
United States	Laurus	TBD*	Not yet begun	Unknown

* = ErgoExergy as technology provider

then, state and private companies have announced a number of projects. Carbon Energy is bringing their parallel CRIP configuation to India with an agreement that calls for Carbon Energy and Singareni Collieries to jointly investigate the possibilities of UGC in Singareni coal areas within the Godavari Valley coalfields. Singareni Collieries has mines in Andhra Pradesh state. Furthermore, Cougar Energy is working in Pakistan, and Linc is working in Vietnam and China. Lastly, the governments of Turkey, Poland, Kazakhstan, and Hungary have begun to investigate UCG potential in their countries.

The Present Status of UCG Research

Although no UCG facilities are currently up and running in the United States, a number of institutions in the country are involved in research aimed at advancing UCG's potential as a clean energy source. Most significantly, two DOE laboratories, the Lawrence Livermore National Laboratory (LLNL) and the National Energy Technology Laboratory (NETL) — both of which have experience in UCG from the 1970s and 1980s — have recently resuscitated their programs.

The LLNL has had the longest and largest role in advancing UCG technology in the United States. Starting in 1974, LLNL helped to plan and execute a number of field programs and developed the CRIP technology, which allows operators to control the growth and location of the underground reactor. LLNL also developed underground gasification models, cavity growth models, and diagnostic and analytical tools. In recent years, the laboratory has developed sophisticated simulation tools as well as site selection and risk assessment approaches. It has also been applying its capabilities in environmental management to stewardship of UCG projects and has begun a new program in carbon management and CCS to be applied to UCG commercial programs.

So far, Purdue University in Indiana is the only U.S. university engaged in UCG research. By contrast, outside of the United States, universities have been playing a major role in developing UCG technology. The Chinese University of Mining Technology (CUMT), for instance, has researched UCG for nearly 20 years and graduated over 100 PhD's on the subject (e.g., Li *et al.* 2007). The privately held ENN Group and its subsidiary XinAo Gas, which also have built a UCG research facility, have supported much of this work. In India, the Indian Institute of Technology (IIT) Bombay has a research program in UCG simulation and engineering (e.g., Khasde *et al.*, 2007), while IIT Bangalore has commenced a program to address policy and regulatory needs. The Oil and Natural Gas Company of India (ONGC) currently supports other programs. In the United Kingdom, Edinburgh and Newcastle Universities have started research programs in UCG applied geoscience while in Canada, the University of Calgary's program focuses on subsurface reactive transport and coupled process simulation. In Australia, UCG research (e.g., Perkins and Sawajhalla, 2006) is receiving support, both in the theoretical domain (at the University of Newcastle) and on the applied level through the CSIRO. In addition, Petrobras in Brazil has begun UCG research through its partnership with Pontifical University in Porto Allegre. Many of these programs, although nascent, are based on deep technical expertise.

Currently, no major U.S. companies have committed to UCG research. However, two large international corporations, BP and Sasol, have in-house programs that have begun active fieldwork. Reliance Industries, Ltd. in India and ENN/XinAo in China also have small but substantial internal programs that include laboratory, field, and simulation efforts.

III Next Steps

As the preceding discussion makes clear, interest in underground coal gasification as a potentially "clean" and economical energy source has been growing in many parts of the world over the past decade, including in the United States. Yet, at present, no concerted government effort exists in this country to advance UCG to full commercial readiness. Given the urgent environmental and energy security challenges facing the United States, a comprehensive research and development program in UCG is overdue. The remainder of this chapter outlines the key aspects of such a program and considers specific options for accelerating and expanding existing initiatives related to UCG technology.

1 Filling the Gaps in UCG Technology

UCG presents many operational challenges. At present, limited technology exists to monitor UCG processes at depth. A lack of knowledge also limits current capacity to manage the composition and temperature of UCG productions. Furthermore, although several designs for UCG production modules have been developed, no clear understanding exists of which designs are most applicable to specific coal resources and geological conditions. In addition, operators have few options for controlling the rate and geometry of cavity growth, which may affect gas composition and environmental integrity. They also have limited information to use as a basis for selecting parameters such as well design, well spacing, and monitoring approaches. At present, the state of the art in UCG technology is confined to a small number of knowledgeable practitioners and their empirical experience and to fledgling modeling and simulation efforts in universities.

In order to build a predictive technical basis for UCG that meets current marketplace standards, a U.S. research and development program must address these prevailing gaps in UCG technology and provide a ready source of answers to the questions posed by developers, operators, regulators, and public stakeholders. A handful of critical tools and technologies can help to accelerate this process:

- ***Basic science***

  A large number of basic science questions remain in the field of UCG. These questions range from the key processes themselves (e.g., changes in the physical and hydrological properties of coal near the reactor wall) to the relevant time scales for characterization and simulation. For instance, there is a lack of clarity about:

  - Whether coal plasticization (which happens at elevated temperatures) affects gasification rates or water influx;
  - Whether the excess hydrogen seen in UCG syngas streams is a product of ash-based catalysis, longer gas residence times in the reactor, or flow through the basal rubble zone;
  - What fraction of the UCG reactor gas might flow through the basal packed bed or the open

channel, and what change in conditions might alter that effect;

- Where in the cavity pyrolysis products form, at what rate they form, at what rate they are consumed in the reactor, the full spectrum of effects that could lead to their migration into groundwater, and how changing UCG operations might reduce their abundance or mobility.

A new program aimed at investigating the basic science of UCG would help fill these holes in knowledge and open up new cost saving and efficiency measures in the future. Many potential research institutions could take part in answering these questions, including the national laboratories and various universities. Because the questions are complex and the time-scales for investigation are likely to be long, sustained funding is required. Annual formal exchanges among all researchers involved in the program will be necessary to ensure the sharing of knowledge and insights. (During the 1970s and 1980s, annual UCG conferences brought scientists and engineers together, helping to create a "golden age" for the technology.) Thus, funds should be allocated to ensure conference participation and allow for publication of research results. Finally, a web site must be established to archive existing information and make both old and new scientific information available to a wide audience.

■ *Advanced simulation*

UCG simulators in current use have limited capabilities. They are often only one-dimensional and can neither match the products of prior field projects, nor accurately predict the natural fluctuations associated with syngas production. Although sophisticated models combining gasification effects with geophysical and hydrological effects in multiple dimensions do exist, they are not widely used, and they still require manual parameterizations between modules and across scales. Improved three-dimensional "coupled simulators" — that is, simulators linking gasification, hydrology, and geomechanics — are needed to:

- Simulate the evacuation of coal and cavity growth;
- Simulate cavity collapse and subsidence;
- Simulate ground water influx as a function of reactor pressure;
- Simulate UCG modules at scale;
- Predict changes in syngas composition given different pressures and temperatures of operation;
- Provide insight into environmental concerns during and after operation.

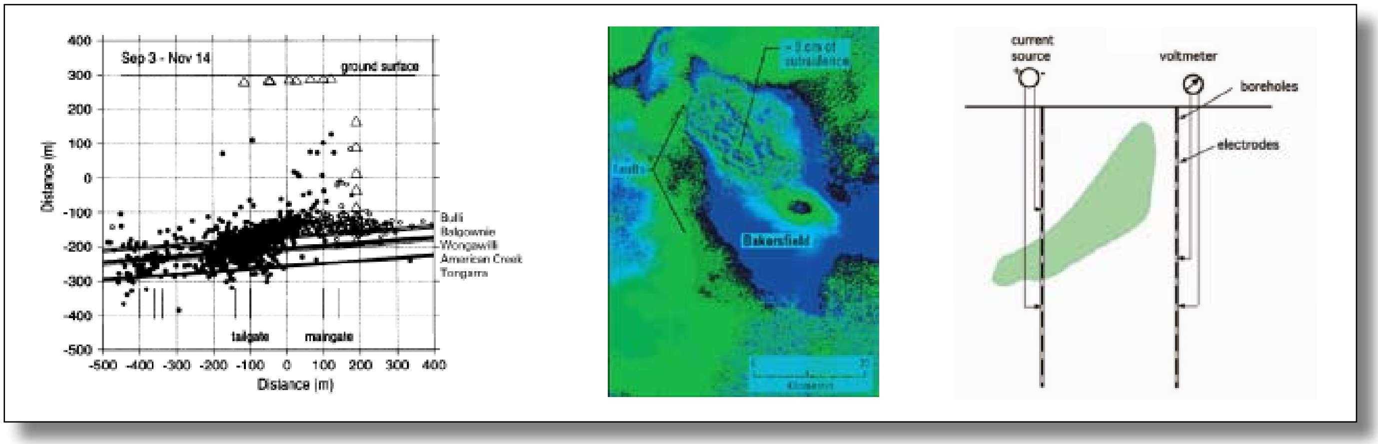
Many currently available simulators may address some or part of these concerns, but they are located across different industries and research institutions. Moreover, many of them are fit to a different purpose (e.g., predicting tunnel collapse) and have not been applied to UCG problems. Thus, a substantial effort is needed to integrate the best features of existing simulation models, to develop new simulation tools, and, in turn, to validate these technologies using records from prior field tests and new field experiments. This initiative will require collaboration between research labs, universities and private companies — each of which will contribute different elements to the process of improving UCG simulation techniques. Ideally, a working group would be established to share initial results and compare approaches. New sets of simulators will then need to be benchmarked against field tests.

■ *Monitoring and verification technology*

Monitoring is necessary to identify key UCG processes, to provide engineering process control, and to detect hazards and failures in the subsurface. Most UCG monitoring took place over 20 years ago. Advanced approaches to geophysical and geochemical monitoring have not yet been applied in the UCG context. Such techniques include the use of micro seismic networks (detectors near the surface that monitor small vibrations in and around the gasification cavity), "InSAR" (a type of radar that uses the interference of radio waves to measure small surface deformations), cross-well or time-lapse seismic evaluations, and micro-gravimetric or electrical surveys. In addition, UCG has special operational and process attributes that both require and make possible new monitoring approaches.

FIGURE 4 **Potential Tools to Monitor UCG**

Left: microseismic monitoring (from Kelly *et al.*, 2002); Middle: Intereference Synthetic Aperture Radar (InSAR); Right: electrical resistance tomography (ERT) (from Daily *et al.*, 2005)



A U.S. program on UCG monitoring technology should thus have the following objectives:

- To identify and select potentially useful tools and approaches such as micro seismic, InSAR, and electrical surveys
- To advance simulation of monitoring in the context of UCG, both for hypothetical rock bodies and field-focused sites
- To ensure validation in the field
- To reduce uncertainty
- To develop novel, fit-for-purpose monitoring approaches

This program will need to build on prior tools and approaches developed for underground mining, oil and gas exploration and development, and data integration. Like a simulation development program, it would begin by using existing tools and data sets from previous field programs and from industrial analogs (e.g., long-wall mining), and it would end in applied field programs. These field programs would initially be aimed at understanding the full range of viable tools and approaches, but their ultimate aim would be to reduce the cost and enhance the performance of monitoring.

Many U.S. research institutions have skill sets applicable to these challenges, including the DOE national laboratories and universities. Yet, to date, none of these institutions has an active program aimed at researching the specific thermal, mechanical, hydrological, and chemical signatures of UCG operations. Similarly, many companies have expertise appropriate to these tasks, but they will need to collaborate with non-commercial research groups to rapidly develop and commercialize UCG technology. In all cases, research in the area of monitoring must be aimed at providing operators with process control and addressing the concerns of public stakeholders.

■ *Module design*

At present, there is a wide range of drilling and completion designs for UCG that define a “module” or a reactor set. Different designs have different well configurations (i.e., vertical or horizontal), spacing, connection methods, as well as ignition and production approaches. Further research is needed to understand the potential benefits or limitations of specific designs given coal seam thickness, rank, and transmissivity. A new program is needed to study module design with the aim of determining which models produce the best syngas and the most efficient resource utilization for different coals and different settings. The goal should be to help operators select and execute modules and drilling strategies for UCG projects.

As the market and industry mature, private companies are likely to carry more of the burden of technology development. In the near term, however, a targeted, federally funded program of this kind will reduce the risk and cost of UCG commercialization. It will provide key information to those interested in siting and operating projects, those tasked with regulating them, and those interested in seeing UCG proceed with the highest possible environmental standards.

2. Advancing Carbon Management

During the heyday of U.S.-based UCG research and development in the 1970s and 1980s, there was not yet a broad recognition of the need to reduce CO2 emissions. Yet, in recent years, the potential for UCG to provide a pathway for capturing and sequestering CO2 has played a major role in driving the resurgence of interest in the technology. A targeted research program is urgently needed to determine the possibilities for carbon abatement associated with the production and use of UCG syngas. The program should focus on three key areas.

- ***Conventional geological sequestration***

  The technology exists today to separate CO2 from UCG syngas and to store that CO2 in geological formations. However, there has not yet been a focused investigation into how operators might apply these technologies together. A new research initiative should examine the potential synergies between UCG and conventional CCS in regions of interest and begin mapping UCG and sequestration resources. In addition, engineering and cost studies should be carried out to determine the commercial viability of UCG with CCS systems in many potential applications.

- ***Reactor zone carbon sequestration***

  UCG creates large voids in the subsurface by gasifying, fracturing, spalling, and evacuating coal. These voids may offer a sequestration resource through an approach known as reactor zone carbon sequestration (RZCS). RZCS could provide a closed loop for a wide range of engineering applications, such as synthetic natural gas or coal-to-liquids production. At present, however, many geological, geochemical and geomechanical questions remain unanswered, stalling deployment of this approach.

  An accelerated research program is needed to examine the key chemical and physical processes involved in RZCS and to determine its commercial viability. There is currently a high level of uncertainty about the degree of characterization required before contemplating reactor zone storage and about the likely fate and transport of CO2 in this setting. Because the process of UCG causes profound changes in the coal and associated host rocks (as a result of exposure to heat, collapse, and reactive chemical agents), it is unclear how CO2 might behave in this altered environment. Thus, a sustained, multi-pronged research effort should aim to:

  - Develop advanced coupled simulators linking RZCS and UCG processes;
  - Initiate laboratory work to understand the physical, chemical, mechanical, and thermal transients associated with UCG and RZCS;
  - Develop a technical roadmap for testing RZCS;
  - Reduce RZCS to a practice in site operation aimed at minimizing contaminant production and transport.

- ***Fit-for-purpose capture technology***

  Most of the carbon capture technologies developed thus far have been geared toward deployment in surface facilities such as power plants. To date, little attention has been paid to how UCG operating conditions might present additional opportunities and challenges for carbon capture. There is thus a pressing need for studies to determine how carbon capture costs might be reduced through the application of fit-for-purpose UCG capture technologies. These technologies could be applied in the reactor zone (e.g., enhanced water-gas shift), in the wellbore (e.g., downhole separation membranes), or at the surface (e.g., enhanced pressure swing adsorption). Researchers should seek to understand the conditions under which UCG operations could improve the cost, performance, or risk profile for carbon capture. Studies should focus on:

  - Integrated engineering — i.e. looking at the potential upsides and downsides of carbon capture engineering for UCG
  - Down-hole engineering to reduce carbon production
  - Down-hole engineering to enhance subsurface water-gas shift
  - Surface facility design for UCG syngas production swings

Relative to conventional CCS technologies (i.e. surface capture and geological CO2 disposal), CCS applied to UCG remains in an early discovery phase. For this reason, a research program aimed at advancing carbon management in UCG should draw on the technological insights of other CCS programs, but proceed independently of those programs so as not to distort public perceptions of the readiness of CCS technology generally. UCG presents many unique challenges and opportunities for carbon capture that warrant a distinct research enterprise.

3. Ensuring Environmental Management

One of the attractions of UCG is its potential to recoup the energy content of coal without the practice of mining. While the elimination of mining has many potential environmental benefits, in-situ conversion and gasification presents a new set of environmental concerns. Any substantial deployment of UCG in the United States must proceed with a high level environmental integrity and focus on the protection of natural resources. Research should begin by addressing the two most critical environmental hazards likely to confront potential UCG operators: ground water contamination and subsidence.

■ *Groundwater protection*

While past UCG research and development programs in the United States left a legacy of many technical successes, two pilots — Hoe Creek 2 and the William's Carbon County project — resulted in environmental problems. At Hoe Creek 2, the problems stemmed from poor siting and operation of the UCG module; at Carbon County, the issues arose from drilling errors and fracturing of the formation during restoration. In both cases, the result was groundwater contamination. Problems relating to project siting, management, and operations can be readily addressed; however, the record of environmental problems with UCG poses a challenge to future operators, who will have to overcome permitting and public acceptance hurdles.

An accelerated research program should thus focus on developing improved practices for site selection, site operation, and project stewardship. The key components of such an effort would include:

- Application of conventional simulators to contaminant fate and transport
- Laboratory work to understand the generation of potential contaminants
- Study of current practices in groundwater protection that are relevant to UCG
- Standardization of procedures aimed at minimizing contaminant production and transport (e.g., operational pressure tolerances) in site operation
- Incorporation of lessons from prior and current research into standard operating practice

■ *Subsidence control*

UCG allows for coal to be evacuated from the subsurface as a gas. This creates voids in the subsurface that could potentially result in surface deformation. At present, most of the available expertise on the problem of subsidence is found in the coal mining industry, which focuses on underground operations within 200 meters of the surface. While experience with subsidence in the context of long-wall mining is analogous to UCG in many respects, questions remain regarding industrial practice in long-wall mine management when full access to the subsurface is limited. Moreover, it is not yet clear what the public perception will be or what regulatory requirements will result, when these practices are applied in the context of UCG.

Research is needed to accelerate the development of techniques aimed at managing and reducing surface subsidence in the context of UCG. Several key elements of this effort include:

- Applying conventional simulators to shallow geomechanics, in particular on discrete failure and fracture
- Conducting laboratory work to understand data requirements for accurate simulation and data collection needs
- Studying current practice in related industries (e.g., coal mining), with a particular focus on long-wall and room-and-pillar mining
- Studying potential impacts of subsidence on groundwater, including impacts on

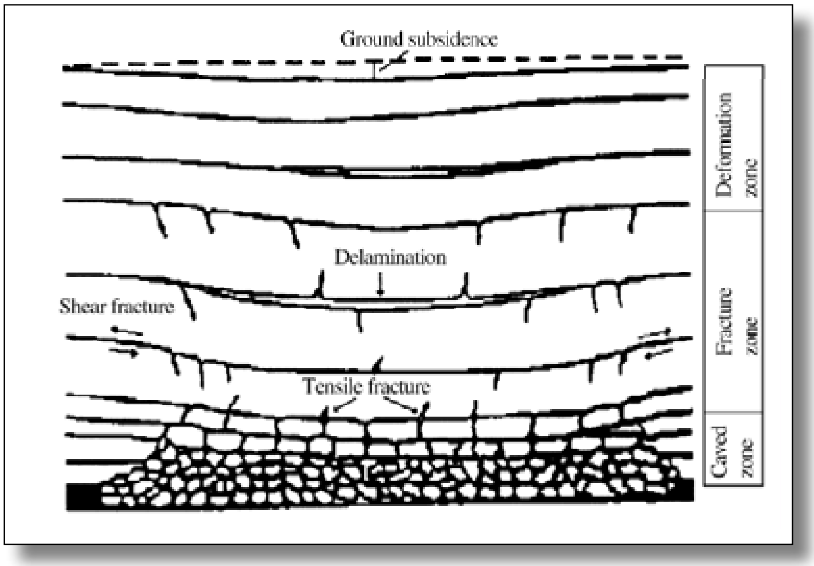


FIGURE 5

Schematic Diagram of Potential Mechanical Failure Modes from Coal Production

From Kelly *et al.*, 2002

UCG process water and local groundwater resources

- Incorporating lessons from prior and current research into standard operating practice

A research program focused on UCG subsidence issues would provide potential operators with insight into how to select and operate sites, and it would help regulators establish minimal requirements for permitting. It would also help to stimulate technology development in this area, while improving stakeholder confidence in UCG as a technology.

4. Increasing Human Capital

One of the most significant barriers to rapid commercialization of UCG in the United States and elsewhere in the world is the lack of technical experts in the field. Currently, no U.S. universities teach classes in UCG or have substantial research programs in this area. The expansion of UCG operations in this country will depend on effective efforts to increase the availability (and improve the quality) of training in all aspects of UCG technology.

Historically, one of the major benefits of the U.S. DOE's university-based research programs has been to educate people that could move into industry. A new DOE research program on UCG is needed to provide for university participation and technical exchange. The program could include workshops and internships. Its explicit aim should be to create a new base of technical knowledge and expertise to further UCG commercialization. Several U.S. universities have thus far expressed interest in participating in such a program, including MIT, the Colorado School of Mines, the University of Wyoming, Purdue University, and Stanford.

Additional funds will be required to support this effort and to accelerate the training of UCG experts. In the third year of a national program, a competition could be held for three to four "centers of excellence," whose mandate would include advancing basic research alongside curriculum development and training in UCG. Attempts to establish such centers earlier would likely yield poor results, since it will take some time for potential program participants to become sufficiently informed about various approaches and problems related to UCG technology.

Finally, establishing a professional network or society for UCG experts will help fulfill the educational requirements for a nascent UCG industry. In the past, the NETL has organized annual CCS conferences and established working groups with industry partners that have fostered important informational exchange. NETL has effectively sponsored university-industry-laboratory efforts that have produced sound and important results in a short time frame. Similar steps could begin immediately for UCG, including hosting conferences and creating archives, public databases, and resource maps, given an appropriate level of initial funding.

5 Establishing a Targeted Field Program

While much of the advanced development work in UCG will proceed in a laboratory setting, a good portion of it will require close coordination with field programs both in the United States and abroad, in order to validate simulations and approaches. A new U.S. field program for UCG will be critical for advancing many aspects of the technology and for fostering new technical discoveries. A targeted field program should include three critical components:

- ***Support for, and collaboration with, commercial UCG pilots***

  Commercial UCG projects in the United States represent an immediate opportunity to refine and test existing approaches for UCG site selection, operation, and monitoring. A U.S. field program should select a number of pilot projects — from two to five — for potential funding and help to provide the appropriate infrastructure. These projects would provide a basis for understanding near-term commercial and regulatory challenges and for filling gaps in knowledge and developing tools for UCG, while protecting a number of public interests. These domestic commercial UCG projects should be treated in a manner that is conceptually akin to the rest of the U.S. clean coal program. The government could provide support for such projects through grants, incentives, tax benefits, and/or loan guarantees. The projects would also represent a significant opportunity to leverage public investments in technology, with resultant environmental benefits and long-term commercial advantages.

- ***Formation of a state-of-the-art UCG facility for research and training purposes***

  A federally-funded domestic state-of-the-art UCG facility would allow for (1) rapid learning through experimentation and (2) the development and testing of advanced scientific methods, simulations, and monitoring platforms.

- ***Support for and collaboration with international field activities***

  Ideally a U.S.-based UCG program would progress in parallel with an international effort. Opportunities for technology sharing with foreign UCG entities will likely improve the technical products in the United States and accelerate learning. This is especially true of field programs. Both China and South Africa have launched active field pilot projects in advance of large-scale commercialization. Australia, India, Canada, and New Zealand are accelerating pilots to test for commercialization. The United States should work toward explicit agreements with other countries aimed at providing technology assistance and basic R&D support in exchange for access to field pilots and their data. This objective could be achieved through bilateral agreements or through umbrella partnerships, along the lines of the Carbon Sequestration Leadership Forum. Cooperative international field projects will increase the pace of R&D, save money overall, and allow participating countries and others with a nascent interest in UCG (such as, Poland, Turkey, and Brazil) to quickly advance their own programs using the best available technology. Issues associated with visas and access will need to be managed effectively in order to streamline the transfer of knowledge and technology.

IV. Draft Budget Requirements

Below are preliminary budget estimates for a four-year federal UCG program that will focus on the R & D objectives discussed above. The numbers are intended to provide a framework for discussion and planning; decisions about important details — such as how much emphasis is placed on international relative to domestic projects, how many entities (universities, private enterprises, national laboratories) will participate, and how much basic science work is needed — will influence the distribution of funds between different program components and total annual costs.

YEAR 1	$10-12M
YEAR 2	$12-20M
YEAR 3	$27.5-37.5M
YEAR 4	$52.5M minimum

A possible breakdown of spending during the first and fourth year of the program could proceed as follows:

YEAR 1 (total draft budget = $11M)

Environmental Protection	$ 2.5M
Carbon Management	$ 2.0M
Conventional CCS	*$ 0.5M*
RZCS	*$ 0.5M*
Fit-for-purpose	*$ 1.0M*
Technology development	$ 3.0M
Simulation	*$ 1.2M*
Monitoring	*$ 0.8M*
Basic Science	*$ 1.0M*
Field Program	
International	$ 3.0M
Other support	$ 0.5M

YEAR 4 (total draft budget = $52.5M)

Environmental Protection	$ 4.0M
Carbon Management	$ 4.5M
Conventional CCS	*$ 1.5M*
RZCS	*$ 1.0M*
Fit-for-purpose	*$ 2.0M*
Technology development	$ 7.0M
Simulation	*$ 2.0M*
Monitoring	*$ 2.0M*
Basic Science	*$ 3.0M*
Field Program	$ 9.5M
International	*$ 7.5M*
US pilots	*$ 17.0M*
US collaboratives	*$ 5.0M*
Other support	$ 7.0M
Centers of Excellence	*$ 4.0M*
Training	*$ 2.5M*
Conference and exchanges	*$ 0.5M*

Conclusion

UCG holds the promise of transforming the use of coal as an energy resource, with positive consequences for the natural environment and energy costs. UCG has a history of success producing syngas for multiple purposes in sites around the world. In recent years, interest in the technology has grown as a result of global climate concerns; the underground well infrastructure used in UCG offers the potential for CO2 capture and sequestration.

Yet, in order for UCG to fulfill its environmental and economic potential it will need to be deployed on a large scale in North America and overseas. Near-term government support is urgently required to produce a reliable base of technical knowledge and expertise that will ensure a commercially-viable UCG industry in the United States. This preceding discussion has outlined the essential components of U.S.-based research and development program aimed at addressing the unresolved problems and unanswered questions in UCG technology and speeding advancement toward full commercialization. In addition to improving basic science understanding, this program will support progress in simulation and monitoring techniques and module design. It will also address those aspects of UCG that are less likely to receive private-sector investment — specifically, environmental management, CO2 capture and sequestration, and university-based training. Each of these areas of research and development will benefit from close collaboration with nascent commercial enterprises in the U.S. and cooperation with international projects and research facilities. The resulting technological advances will ultimately be tested and refined in the context of a federally funded targeted field program that will serve as critical a data source for commercial UCG projects going forward.

Note: It is possible for much recommended federally funded R&D to begin immediately. This would include the research on development of simulation tools and experimental programs. Moreover, some commercial field projects in North America or overseas could serve as possible locations to develop and test novel monitoring, simulation, drilling, or environmental protection technologies, tools, and approaches. This model would follow the Weyburn CCS project, wherein scientific and technical investigations benefited from access to the surface and subsurface at a commercial CCS project site. The costs for these initial efforts would be relatively low, and they would provide a platform to determine the role, viability, and features of a US government-sponsored field program. ■

Recent Reports on UCG

Below is a list of several reports that may be useful to decision makers in considering current practice and understanding with respect to UCG technology.

Best Practices in Underground Coal Gasification (draft), Burton *et al.*, 2006 (https://co₂.llnl.gov/pdf/BestPracticesinUCG-draft.pdf)

Underground Coal Gasification, in, The Urgency of Sustainable Coal, National Coal Council 2008, (http://www.nationalcoalcouncil.org/Documents/Urgency_of_Sustainable_Coal.pdf)

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Review of Environmental Issues of Underground Coal Gasification, Sury *et al.*, 2004 (http://www.berr.gov.uk/files/file20034.pdf)

Status Report on Underground Coal Gasification: Office of the Principle Scientific Advisor (India) 2007 (http://psa.gov.in/writereaddata/11913281701_ucg.pdf)

Clean Energy from Underground Coal Gasification in China, Creedy DP, Garner K, 2004, (http://www.berr.gov.uk/files/file20060.pdf)

Detailed Evaluation of Process and Environmental Data from the Rocky Mountain 1 Underground Coal Gasification Field Test, Gas Research Institute, GRI-97/0331, 1998

The International Energy Agency's Clean Coal Program (http://www.iea-coal.org.uk) is in the process of publishing a report on UCG that should be released later this year. The draft report is available at http://www.iea-coal.org.uk/site/ieacoal/publications/draft-reports.

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CHAPTER 2

Mobilizing Next Generation Coal Gasification Technology for Carbon Capture and Sequestration

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Coal gasification converts coal feedstock to a gas that can be used to produce chemicals, fuels or power. It is a critical climate change mitigation technology that can be applied to produce power from coal with CCS and many studies suggest that coal gasification with CCS may the lowest cost "above ground" low-carbon form of new coal power production (MIT, 2007; DOE/NETL, 2007). Historic coal gasification research, development and demonstration (RD&D) programs have produced several commercial technologies and promising pre-commercial technologies, some of which are profiled in this chapter. In comparison with today's commercially available coal gasification technologies, advanced coal gasification technologies can potentially lower costs, improve coal conversion efficiency, offer flexible conversion products (syngas, methane or hydrogen) and increase fuel flexibility. In turn, these benefits could accelerate adoption of low-carbon coal power technology.

Coal gasification technology has evolved in various commercial applications for more than a century, with a "surge" of domestic R&D support in the 1970s in response to the oil embargo crisis. Looking forward to a climate constrained world, coal gasification's primary purpose is shifting from traditional chemical and liquid fuel industry applications to low-carbon power and natural gas production. This recent shift in the public importance of coal gasification needs to be addressed by an evolved public RD&D program that fully reflects a major shift in the technology's purpose. An expanded and adequately funded federal advanced coal gasification RD&D program is now needed to accelerate commercialization of advanced coal gasification technology to help society address key climate challenges.

Gasifying coal is in many ways like refining crude oil: It is a method for transforming energy-rich raw material into more valuable (and cleaner) fuels and other products. Gasification technologies may offer several advantages over coal combustion for power generation, including improved efficiency, potential for lower-cost CO2 removal, substantially lower air pollution emissions, reduced volumes of dangerous solid waste and reduced water consumption. While these advantages would be quite valuable to society, use of coal gasification to produce power is not yet fully competitive with coal combustion. And in the United States, the historic availability of abundant low-cost oil and natural gas feedstocks in the petrochemical industries has constrained broad application of coal gasification technology. In contrast, there has been an "explosion" of coal gasification applications in China's chemicals industry over the past decade where natural gas feed stocks are expensive and scarce.

As a result, there has been limited market "pull" towards commercial demonstration and deployment of gasification technologies for power production. At the same time, there has been limited "push" in the form of government funding to move these technologies out of the R&D world and into commercial operation, with funding for pioneering commercial demonstration plants limited to early entrant technologies. If the United States is to realize the potential advantages that gasification technologies could provide, it must create both a market "pull" and a government "push." This can be done by programs that place an effective price on CO2 emissions or otherwise reward CCS and through carefully crafted funding efforts to "push" potentially more beneficial technologies into the commercial arena. This is especially true for "advanced" or "breakthrough" gasification technologies that may offer even greater advantages than their predecessors.

The chapter discusses several advanced coal gasification technologies, which are representative of a broader universe of advanced gasification technologies that offer considerable commercial and environmental promise in a carbon-constrained world. This chapter reviews each technology in the context of coal gasification and carbon capture generally, discusses some of the challenges faced by this class of technologies on the path to commercialization, and concludes with recommendations for government support in this area. The details of our review follow. In brief, our recommendations are:

1. The existing RD&D "pipeline" for advanced gasification technologies should be expanded significantly. This expansion should include:
    - Increased support for fundamental gasification research and pre-commercial gasification R&D efforts
    - An expanded process for systematically interacting with technology developers to identify and meet development needs that would not be addressed by the private sector and that are critical for scaling up to commercial applications (examples include process engineering and feasibility analyses)
    - Construction of one or more shared user facilities for advanced gasification systems development
2. Carefully structured public-sector financial support should be provided to allow construction of initial commercial-scale projects for strong technologies despite risk aversion in commercial credit markets. This "first commercial project" fund, which would be structured as a semi-autonomous corporate agent of the federal government, would:
    - Offer loans, loan guarantees, and insurance products to help riskier technologies bridge the "Valley of Death" to commercialization
    - Sustain its operations through fees for its services as well as returns on equity invested in projects (or other arrangements with technology developers)
    - Support private-sector investment through the creation of privately owned funds and other investment approaches

Background

This chapter profiles seven technologies that differ significantly from coal gasification systems currently available in the marketplace. Commercial gasification systems include gasifiers originally developed by the chemical and refining industries (for example, the Texaco — now GE — technology, the Shell coal gasification system and the E-Gas technology of ConocoPhillips), all of which emphasize reaction of coal with oxygen and steam at high temperature (above 2,000°F) and moderate or higher pressure (above 400 psi) in entrained flow configurations (where the gasification occurs rapidly as the coal and steam-oxygen mixture moves freely through a reaction chamber). (Box 2.1 includes a basic description of coal gasification processes.) Despite general success, with dozens of these gasifiers around the world generating synthesis gas for commercial uses, important challenges have become evident:

- Current systems are very capital-intensive; they require large pressure vessels made of specialty materials and lined with refractory or water wall membranes for thermal protection.
- Current systems typically have large internal power requirements because they use air separation units (ASUs) to generate the oxygen required for the gasification reactions.
- Current systems would benefit from improved feed flexibility and the ability to mix feedstocks or use low carbon feedstocks.
- Current systems would benefit from improved efficiency.
- Current systems would benefit from improved reliability, availability, and maintainability ("RAM").

These challenges have contributed to limiting the deployment of gasification technologies in the power sector. Despite this, the major gasification technology providers have participated in commercial-scale coal gasification power generation projects (called integrated gasification combined cycle or "IGCC") in the past fifteen years. GE's gasification technology is in use at TECO Energy's Polk County IGCC plant in Florida; ConocoPhillips's E-Gas technology is in use at the Wabash River IGCC plant in Indiana; Shell's coal gasification technology is in use at the Nuon IGCC plant in the Netherlands; and Prenflo's gasification

Box 2.1

Fundamental Processes in Conventional Coal Gasification

Conventional gasification relies on a handful of basic chemical processes: combustion (in which some fraction of the carbon and other material in the coal is burned, releasing heat that is used to drive other chemical reactions); pyrolysis (in which the heat from combustion forces volatile compounds like methane out of the coal, producing a flammable gas and leaving behind a porous carbon-rich material known as char); and the water-gas reaction (in which char reacts with very hot steam to produce syngas – a mixture of hydrogen – H2, carbon monoxide – CO, and carbon dioxide – CO2). In practice, of course, gasification is much more complex than this simple description suggests.

The key chemical reactions for conventional gasification are described in the table below, along with several important reactions (hydrogasification, water-gas shift and methanation) which occur either within a gasifier or in related downstream processing equipment.

Different gasifier designs have been developed to take advantage of different aspects of these reactions, tailored to different coal feed types. Moving-bed gasifiers use reactors packed with coarse coal through which pass hot gases and steam from a distinct combustion zone. They are characterized by long coal residence times (tens of minutes), higher steam requirements (to moderate the bed temperature and keep the coal ash from sintering), and lower oxygen requirements. Fluidized-bed gasifiers use reactors that contain a bubbling bed of finely crushed coal and other materials through which steam, oxidant, and potentially other gases are continually blown. They are characterized by a more uniform temperature distribution, more rapid gasification, and higher consumption of oxygen than moving-bed gasifiers. Entrained-flow gasifiers use reaction chambers where very finely ground coal, oxidant, and steam react very rapidly under high temperature and pressure while moving freely though the chamber. They are characterized by short residence times, tight requirements on coal (especially ash content and composition), higher oxygen requirements, and production of very hot syngas containing significant thermal energy. Most of today's commercial gasification systems are entrained-flow designs (e.g., GE Energy, Siemens, ConocoPhillips, Shell, and Mitsubishi Heavy Industries) or moving-bed (British Gas/Lurgi - BGL).

The advanced gasification technologies that are the subject of this report include processes beyond those described above. In molten bath gasification, for example, feedstock is injected into or onto a bed of liquid material, often hot metal, and the bed can act both as a catalyst and as a heat transfer medium. In catalytic gasification, a catalyst can be added to a fluidized bed gasifier, or combined with the coal feed in some manner or other, to promote methanation reactions in the gasifier, which can improve efficiency by balancing exothermic and endothermic reactions in the same process vessel. Other techniques employ novel arrangements and/or staging of more conventional processes to emphasize different reactions (e.g., hydrogasification followed by steam methane reforming – the inverse of reaction (9) – to produce H2 both for the hydrogasification reaction and for syngas). ■

Chemistry of Coal Gasification

Reaction	Heat[1]	Name	Comments[2]
(1) CH_x + heat → C + CH_4 +	N/A	Pyrolysis	Variable depending on fuel
(2) C + ½O_2 → CO	+	Oxidation	Combustion; moderate speed
(3) CO + ½O_2 → CO_2	++	Oxidation	Combustion; fast; consumes O2 as available
(4) C + CO_2 → 2CO	- -	Boudouard	Related to combustion process; moderate speed
(5) C + O_2 → CO_2	+++	Oxidation	Combustion; moderate speed
(6) C + H_2O → CO + H_2	- -	Water-gas	Slow; requires high T
(7) C + 2H_2 → CH_4	+	Hydrogasification	Moderate speed; favored by lower T, high P
(8) CO + H_2O → H_2 + CO_2	+	Water-gas shift	Favored by lower T; promoted by catalysts
(9) CO + 3H_2 → CH_4 + H_2O	++	Methanation	Readily promoted by catalysts

[1] "+" signs indicate approximate relative amount of heat released by the left-to-right reaction; [2] "T" and "P" refer to temperature and pressure

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Sources: Compiled from Higman and Burgt (2008), and from Ruprecht, Schäfer and Wallace (1987).

technology is in use at the Puertollano IGCC plant in Spain. A new IGCC plant based on GE's technology is also under construction in Indiana. There are other IGCC installations as well, using heavy liquid hydrocarbon feedstocks (e.g., the GE-based IGCC systems at the Sarlux and ISAB refineries in Italy and the Shell-based IGCC system at the AGIP Sannazzaro refinery in Italy), and significant non-IGCC gasification installations (including the Dakota Gasification Company's substitute natural gas production facility in Beulah, North Dakota, which uses Lurgi gasifiers). Kellogg, Brown and Root's transport reactor integrated gasifier (KBR's TRIG), which has undergone extensive development at the DOE/EPRI/Southern Co.-funded Power Systems Development Facility in Alabama, may also soon move into the commercial market with an IGCC project in Kemper County, Mississippi that includes integrated CCS. (Box 2.2 provides a short history of gasification technology.)

Recently several additional technologies offering potential incremental improvements over existing gasification technology for some feedstocks or applications have entered the marketplace. These technologies include the Siemens, East China University (ECUST) and Chinese Thermal Power Research Institute (TPRI) entrained flow oxygen-blown gasifiers and the Mitsubishi Heavy Industries (MHI) gasifier (which can be operated in either an "air-blown" or "oxygen-blown" configuration). Several of the Siemens gasifiers have been sold for commercial use in non-power applications, and several power projects based on the Siemens technology are under development (Siemens, 2007 and 2008). A 250 MW IGCC project using the MHI coal gasification technology has been operating for about a year in Nakoso, Japan (Clean Coal Power, 2008). The Lurgi series of fixed-bed steam-oxygen gasifiers, which has been deployed successfully around the world for many years, has also been improved and upgraded (Envirotherm, 2003). Although these improved technologies are important, they suffer some of the same cost and performance hurdles as their predecessors in the role of power production.

In contrast, the advanced gasification technologies addressed in this chapter may offer potentially significant advantages in terms of system cost, performance (including reliability and feedstock flexibility) and simplicity, among other virtues. As a result, these technologies — none of which have been developed at commercial scale — could provide a step-change improvement in the cost and performance of coal gasification systems and could thus accelerate and expand low carbon power production from coal and other carbonaceous feed stocks.

The technologies profiled in this chapter are:

- Bluegas from GreatPoint Energy — a method for producing substitute natural gas directly from coal and other carbonaceous materials using a single fluidized bed gasifier with an entrained catalyst
- Calderon Process from Energy Independence of America Corporation — a method for producing dual streams of clean synthesis gas (or "syngas") — one hydrogen-rich, one carbon monoxide-rich — from staged pyrolysis of coal and other carbonaceous material followed by air-blown slagging gasification of char
- Viresco Process (formerly the CE-CERT process) from Viresco Energy — a method for producing syngas for chemicals production and power generation using thermally-forced steam hydrogasification of moist carbonaceous fuels coupled with steam methane reforming
- HTHG from ThermoGen Hague — a process for producing substitute natural gas from low-rank coal using very high temperature steam gasification without significant oxygen
- HydroMax from Alchemix — a method for producing synthesis gas from coal and other carbonaceous materials using molten bath technology adapted from the metal smelting industry
- Wiley Process from SynGasCo — a method for producing synthesis gas from coal and other fuels using pyrolysis, gasification, and non-catalytic syngas reforming at moderate temperature and low pressure without the addition of external oxygen
- Ze-gen — a method of producing synthesis gas from organic waste and other carbonaceous materials using liquid metal gasification technology drawn from the steel industry

There are additional advanced gasification technologies that could offer advantages similar to the technologies noted above. These include NC12 (formerly Texas Syngas, a molten bath gasification

Box 2.2

A Short History of Coal Gasification

Conversion of coal and other carbon-rich solid materials into gaseous fuel has been around for a long time and was first commercialized in the early 1900s. At that time, production of ‘town gas’ from coal was widespread in both the United States and Europe and continued until the practice was finally displaced by distributed natural gas several decades later. In the 1920s and 30s, scientists at U.S. Bureau of Mines laboratories near Pittsburgh, Pennsylvania experimented with the Bergius Process for the direct production of liquid fuels by hydrogenation of coal. This process fueled much of Germany’s war effort during World War II and was of keen interest to U.S. policy makers. In the 1940s and 50s coal utilization work was expanded at the Bureau’s Morgantown, West Virginia laboratory to include gasification of coal with oxygen and the subsequent production of liquid fuels using the Fischer-Tropsch process. Authorized under the Synthetic Liquid Fuels Act of 1944 and its amendments, the total public investment in these programs through the early 1950s was more than $80 million. At the same time, private companies were investing in gasification and related technology: Texaco’s gasification technology, for example (now GE Energy), was first tested at small scale in 1946 at the company’s Montebello, California laboratory; work on Shell’s oil gasification technology began in the early 1950s in Europe; in South Africa, Sasol employed Lurgi coal gasification technology on a commercial scale starting in 1954. Other companies (e.g., Winkler) were also active.

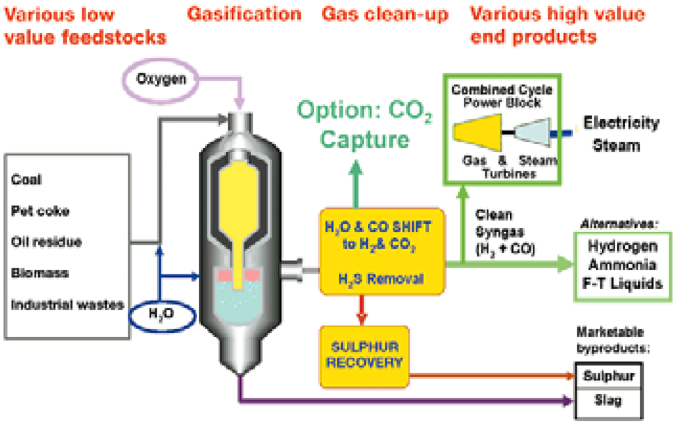
After a relatively dormant period in the 1960s, interest in gasification increased again in the 1970s. The first IGCC operated in Germany in 1969, development work on coal gasification continued at Texaco and Lurgi, Krupp Koppers joined Shell’s coal development work in 1974 and development of coal gasification by Dow Chemical lead to operation of a pilot plant in Plaquemine, Louisiana in 1978. During this time the U.S. Energy Research and Development Administration (ERDA) also put significant emphasis on coal gasification in response to oil shortages, and numerous gasification technologies were explored at laboratory and pilot plant scale. Many of those technologies are discussed elsewhere in this report.

The 1980s saw the beginning of large-scale commercial activity on gasification in the United States The first large-scale use of the Texaco gasifier was by Eastman Chemical at their Kingsport, Tennessee facility in 1983; the joint Texaco – EPRI – Southern California Edison ‘Cool Water’ IGCC project started in California in 1984; and Dow’s Louisiana Gasification Technology, Inc. (LGTI) IGCC started in Plaquemine in 1987. The 1980s also saw the rise of the U.S. Synfuels Corporation, which provided public investment in synthetic fuels projects (including the Dakota Gasification Company’s Lurgi-based coal-to-substitute natural gas (SNG) production facility in North Dakota) and saw the fall of U.S. Synfuels due to falling oil prices, lack of industry participation, and allegations of mismanagement.

While many of the more than 10,000 town gas production plants in the U.S. left an environmental legacy of tar and heavy oil pollution due to inefficient gasification, that early experience (and significant public and private investment) contributed to the development of today’s modern gasifiers which operate at higher temperatures and pressures, under much more tightly controlled conditions, and which efficiently convert almost all of their carbon feed into useful products and CO2. Generally the inorganic constituents in the coal feed are reduced to vitrified (glass-like) slag or ash in today’s gasifiers. Worldwide installed gasification capacity is now in excess 56,000 MW (thermal). ■

Sources: Compiled from DOE (2007), Sasol (2001), EPRI (2007), Raloff (1985), Gasification Technology Council (2008). Also US DOE Website: http://fossil.energy.gov/aboutus/history/syntheticfuels_history.html and http://www.fossil.energy.gov/programs/powersystems/gasification/gasificationpioneer.html

FIGURE 1 **Simplified Gasification Schematic**



Source: IPCC (2005), Figure 3.1.4.

technology); Eltron Research (a reactive membrane-based gasification technology); Diversified Energy (utilizing the HydroMax gasification technology profiled here from Alchemix); iron-based chemical looping gasification technology, which is under development at Ohio State University; the hydrogasification technology under development by a consortium led by the Arizona Public Service Company; technologies under development by Research Triangle Institute and Pratt & Whitney Rocketdyne; and plasma gasification technologies. Other gasification technologies, developed for use with biomass and hydrocarbon-rich waste streams, might also be readily applicable for use with lower-rank coals, but were not included directly in our sample. Those technologies have been supported by the renewable energy programs of the U.S. DOE, often through the National Renewable Energy Laboratory in Colorado (BCS Incorporated, 2005).

The central characteristic of this general class of technologies, which they share with the more established gasification technologies, is that they use coal or other carbonaceous material (including petroleum coke and various forms of biomass) to produce either (1) synthesis gas or "syngas" (which is composed primarily of hydrogen and carbon monoxide) or (2) synthetic or substitute natural gas ("SNG"), which is predominantly composed of methane. Where CO2 is also produced, it can be separated from the syngas or SNG stream and vented to the atmosphere or sold for enhanced oil recovery, among other uses. Syngas can be used as fuel for power generation (for example in a boiler or in a combustion turbine) or as a raw material for the production of an almost limitless array of chemical products such as methanol, hydrogen, SNG, dimethyl ether (DME), and ammonia. The carbon contained in the coal feedstock provides most of the system's energy, even if the ultimate product is hydrogen for use in a very low-emission IGCC power plant (with carbon removed via the reaction of carbon monoxide in the syngas with water to form CO2 in a water–gas shift reaction), or SNG (produced by hydro-gasification or methanation). Ultimately, the coal's carbon is rendered as CO2 — either during gasification and subsequent processing (at which point it can be separated from the remaining gas stream prior to combustion) or when the resulting fuels or products are burned (which converts most of the carbon in carbon monoxide or methane to CO2). CO2 produced during gasification and subsequent processing is relatively concentrated and can be readily captured at a pre-combustion stage and sequestered from the atmosphere (e.g., by injection into saline water formations deep below the earth's surface). Thus, syngas in its many forms generally represents a thermodynamically preferred route to "de-carbonized" coal.

Figure 1 above is a simplified schematic of a generic gasification process with syngas cleanup and CO2 capture, followed by syngas use for electric power production in a combined cycle combustion turbine and steam turbine, as well as chemicals production. Although not indicated in the figure, production and use of SNG would be similar (with the clean syngas converted to SNG before being used in downstream processes).

Carbon Management

The technologies discussed in this chapter range from “gasification only” processes to complete coal-to-energy systems concepts. Most have been under development for many years. As noted above, the imperative of addressing climate change requires that commercial application of these gasification technologies include clear and fully developed plans for capturing and processing CO2 for sequestration. It is also critical that technology developers address the integration of their gasification technologies with systems that produce electricity, natural gas, or other products. In addition, technology development must include considerable detail regarding the integration of carbon capture, processing, and compression as part of such energy systems. In short, carbon management is not something to “get real” about only at some point “down the road”—rather it should be fully integrated into the process of commercializing these next generation gasification technologies. This view is reflected in our recommendations, which are discussed below.

The Review Process

Interviews and Surveys

Seven different advanced gasification technologies are profiled in this chapter. These are not the only such technologies in existence. Rather, they were identified in some manner — either through the personal knowledge of the report authors, via references from the gasification field, or in industry publication or conferences — as having the potential to offer significant advantages once commercialized. Although the companies that are currently developing and nurturing these technologies face myriad challenges — including serious capital constraints that have been exacerbated by current economic conditions — only one of the companies we originally approached ultimately chose not to participate.

The content and recommendations presented here should be understood in light of the process used to develop this report. Our aim is to briefly describe each technology and provide a qualitative understanding of the RD&D (and other) needs confronted by this class of technologies in attempting to reach commercialization. The report authors researched each technology using publicly available information and considered historical funding (if any) from DOE. The report authors then developed a questionnaire intended to focus on the development, historical public funding, and current RD&D needs of each technology, among other data items. A telephone interview with each of the company participants covered these issues in greater detail. These interviews ranged in length and scope, but all followed the general framework of the questionnaire.

Following the interview, all of the companies chose to complete the questionnaire themselves recognizing that it would form the basis for the content in this report. The reasons for this preference varied, but included concerns about confidentiality and the protection of intellectual property. Similarly, the content of this report necessarily has been limited by the simple fact that none of these companies yet knows precisely what a fully developed commercial plant would look like (although some know more than others).

One point emerged clearly from our dialogue with these companies: all of them have strong opinions, experiences, and evidence about what is needed to push their technologies from development to actual commercialization. Each of the companies we interviewed reviewed this report prior to publication, but the accuracy of specific information about individual technologies has not otherwise been verified. An internal advisory group of expert technical reviewers did provide a form of objective peer review. In this way, the report aims to present an accurate overall picture of the state of these advanced gasification technologies generally, while compiling and synthesizing information about their RD&D needs as voiced by the companies involved and by expert technical reviewers. This report should not, however, be construed as providing an independent technical assessment or evaluation of any specific technology — or for that matter of any specific claims regarding a particular technology. Rather, it is intended to provide a roadmap to move this important suite of technologies forward.

Advanced Gasification Processes

Short profiles of the seven selected advanced gasification technologies are included below. These profiles are based on information provided by the technology development companies during our review process and from various publically available sources.

Bluegas from GreatPoint Energy

The Bluegas process from GreatPoint Energy – called "hydromethanation" – uses a fluidized bed reactor to produce substitute natural gas (SNG, predominantly methane) directly from carbonaceous material using an integrated set of thermally-balanced, catalyst-promoted gasification and methanation reactions. Overall thermal efficiency of the single-step process is expected to be much higher than more conventional SNG production which relies on separate processing steps for gasification, water-gas shift, and methanation. Conventional means are available to separate from the produced methane, CO_2, sulfur, and other impurities, resulting in pipeline quality natural gas. GreatPoint reports that coal (including Power River Basin sub-bituminous), petcoke, and biomass can be used with the process.

DOE invested significant resources into the study of catalytic gasification in the 1970s and 1980s, including construction of bench-scale reactors in conjunction with Exxon Research and Development. GreatPoint leased a 1-3 ton-per-day (tpd) flex-fuel gasifier at the Gas Technology Institute in Illinois to perform testing on a range of feedstocks. These tests validated the performance characteristics of the hydromethanation process. Since 2003 GreatPoint has worked with continued public sponsorship (e.g., modest funding from the Alberta Energy Resources Institute and the Massachusetts Technology Collaborative) and private investment (from venture capital firms such as Kleiner Perkins and companies such as AES, Dow Chemical, Peabody Energy, and Suncor Energy) and has refined the technology to produce a commercial process that includes an improved catalyst recycle system, higher efficiency, lower capital cost and reduced CO_2 footprint. A BlueGas demonstration facility for testing a wide range of feedstocks has recently entered commercial operation in Somerset, Massachusetts, and the company reports that external technical review indicates the process is ready for scale-up to commercial application. Plans are in place for a commercial demonstration project in China with a large power company and GreatPoint is investigating other opportunities in North America.

HydroMax from Alchemix

The HydroMax process under commercialization by Alchemix Corporation uses a molten bath technology adapted from the metal smelting industry to produce low pressure, high temperature, moderate-Btu syngas from carbonaceous feeds including high-moisture, low-cost fuels like biomass, lignite and Powder River Basin sub-bituminous coal. The company reports that cold gas efficiency of the gasification process can be as high as 84 percent for some high-Btu fuels when the company's proprietary "chemical quench" (reaction of char and CO_2 to produce carbon monoxide) is used.[1] The syngas produced by the process can be cleaned by conventional processes and used for production of hydrogen, substitute natural gas, or chemicals (e.g., methanol). In the process the molten bath acts as both a heat transfer medium and an oxygen carrier, splitting water molecules to produce hydrogen and to convert carbon to carbon monoxide gas. When materials such as petcoke are processed, metals recovery (e.g., nickel and vanadium) can be significant.

The HydroMax process has been developed since 2000 by a team including Alchemix, Pittsburgh Mineral and Environmental Technology, Commonwealth Scientific and Industrial Research Organization (CSIRO, Australia's national labs), Diversified Energy, and others. The process has been tested in a 0.3 meter diameter pilot scale bath smelter at CSIRO. To complete detailed design for a first commercial plant, a concept for a 1.0 meter diameter pre-commercial demonstration plant has been developed. Much larger bath smelters (e.g., 8 meter diameter) are already in use in the metal smelting industry. Alchemix reports that the gasification and downstream processing have been modeled using Aspen-Plus and FactSage. Recently the technology has received two Small Business Innovation Research awards from the DOE's National Energy Technology Laboratory (NETL). In 2005 it was a finalist for a Platts Global Energy award.

Calderon Process from Energy Independence of America Corporation

The Calderon Process under commercialization by Energy Independence of America Corporation (EIAC) uses a sequence of pyrolysis reactors and hot char gasifiers to produce two distinct syngas streams — a hydrogen-rich stream from the pyrolysis reactions and a low-Btu stream from the char gasifiers — with the former suited to methanol or other chemicals production and the latter suited to power generation in a combined cycle gas turbine (CCGT). The technology has grown out of coking and blast furnace experience in the steel industry. Crushed, run-of-mine coal is fed without pre-treatment into a horizontal pyrolysis reactor with small amounts of oxygen followed directly by gasification of the hot, porous char in a vertical air-blown slagging gasifier. The company reports that any type of coal can be used, and multiple configurations are possible (e.g., electric power, liquids, SNG). EIAC has developed a proprietary sorbent-based hot gas clean-up technology for use with their process, and is involved in development of a process to convert unseparated nitrogen and CO_2 in combustion flue gas into fertilizer.

A PDU with capacity of 10 tons per hour (tph) was operated (at reduced throughput to conserve funding) in the late 1980s and early 1990s in Alliance, Ohio, and EIAC reports that the pyrolysis, char gasification, and solids handling aspects of the technology were demonstrated there, as was the proprietary hot-gas cleanup system. Development of the Calderon Process was facilitated by moderate funding

[1] There are many measures of efficiency. In power generation applications the overall efficiency of an integrated process, or its inverse – the heat rate – is often used when comparing technologies. Overall efficiency values between 30 percent and 60 percent are common in different power generation settings, with values quoted with reference either to "HHV" – higher heating value, representing all of the heat energy contained in the fuel – or "LHV" – lower heating value, consisting of HHV less the heat energy required to vaporize any water produced as a result of fuel combustion. When gasification systems are discussed in isolation often only the "cold gas efficiency" is quoted. Cold gas efficiency represents the chemical efficiency of the gasification process itself (amount of energy in the product gas vs. amount of energy in the feedstock), and is not directly comparable with overall efficiency measures because it excludes the energy inputs to the gasification process (for example, steam and compressed, purified oxygen) and other internal energy demands (for example, gas cleanup equipment).

from the federal government and the state of Ohio. The process has been evaluated on a confidential basis by Bechtel Corporation and other commercial entities, and a conceptual design for a 640 MWe (net) commercial power plant has been developed.

Wiley Process from SynGasCo

The Wiley Process developed by Thermal Conversions, Inc. and commercialized by SynGasCo utilizes a two-step pyrolysis and gasification/non-catalytic steam reformation process at low pressure and moderate temperature to produce a moderate-Btu syngas without the need to supply external oxygen or air. Fuel (especially pet coke or coal) is fed dry, and steam from an external source is added to sustain the reactions. Syngas is cleaned with a cyclone ash removal system, a proprietary "ion-water" technology that results in solid byproduct containing sulfur, mercury, and other contaminants, and a moisture condensation system. The company reports that the system has an overall cold gas efficiency of 70 percent after accounting for syngas used to produce process heat and steam.

The Wiley Process has been developed without public funds. A pilot plant with 175 tpd design capacity was constructed in 2007 in Denver and is now operating as a test facility at the University of Toledo. The unit has used petcoke, Powder River Basin coal, Ohio coal, woodchips, and rice hulls, and can use other moist carbonaceous feedstock. Syngas produced from the process is used to offset natural gas used in the university's boiler systems, and technical evaluation of the process is ongoing, including work by the University of Toledo and DOE-funded work by TSS Consultants on behalf of the City of Gridley, California. Commercial plans for the process include re-powering of smaller, lower-efficiency boilers in the U.S. coal power fleet.

Ze-gen Process

Ze-gen, Inc. has developed a system for gasifying organic wastes using a molten iron bath produced within a channel induction furnace of the type commonly used by the steel industry. Feedstock and oxygen are introduced into the molten bath using submerged lances and moderate-Btu syngas is produced at low pressure. The company reports that standard syngas cleanup (e.g., particulate removal) can be used if necessary.

Ze-gen's technology was developed with minimal public support by integrating existing commercial technologies into a new technology platform, and a large-scale demonstration facility is operating in Massachusetts. The company plans to develop this technology into small modules (250 million Btu/hr) that can be used to provide syngas to existing industrial consumers of natural gas and fuel oil, or alternatively can be used to provide gas for blending in natural gas pipeline systems. The economics of the process represent a synergy between production of energy and reduced tipping fees for waste management.

Ze-Gen reports that they are evaluating a number of improvements to their demonstrated process, including mechanisms to obviate the need for submerged lances and substitution of a copper bath for an iron bath to reduce energy requirements. Ze-Gen currently is focusing on biomass and industrial waste stream fuel inputs to produce syngas for power generation or other uses.

Viresco Process from Viresco Energy

The Viresco Process couples moderate temperature, moderate pressure steam hydrogasification in a wet slurry fed reactor with downstream steam methane reformation to produce syngas with a composition suitable for chemicals production (e.g., methanol), electricity, or other uses. Hydrogen for the hydrogasification reactions is extracted from syngas following reformation, and no external source of oxygen or hydrogen is used (except during startup). Solids are recycled within the process to increase heat transfer for the (endothermic) gasification reactions, with a fraction of the recycled solids combusted along with excess hydrogen to raise steam for internal power requirements. The company reports that feed can be any carbonaceous material, with blends of sub-bituminous coal and wood receiving recent attention.

Developed since 2003 by the College of Engineering — Center for Environmental Research and Technology at the University of California, Riverside (CE-CERT) — using funding provided by Viresco Energy and the City of Riverside, the Viresco Process has been simulated using ASPEN-Plus by DOE under a CRADA. An independent review of the technology by NETL (including detailed heat and mass balances and financial calculations) will be published soon, and suggests that the Viresco process offers an opportunity for increased efficiencies and reduced capital costs over partial oxidation gasification for certain configurations. A 2 pound per hour (pph) bench scale kiln reactor and several batch and drop-down reactors have been used to test the basic process and to acquire data, as has a fluidized bed reactor at the Energy & Environmental Research Center at the University of North Dakota. A 10 pph PDU concept is under development, and a 20 tpd pilot plant is proposed for Alton, Utah.

HTHG Process from ThermoGen Hague

ThermoGen Hague's high temperature hydrogasification (HTHG) process uses very high temperature steam raised in a hydrogen-fired furnace to convert carbonaceous feeds, especially reactive material like Power River Basin sub-bituminous coal, into hydrogen-rich syngas followed by hydrogasification to produce substitute natural gas. In one of its configurations, the process uses two moderate-pressure, moderate-temperature reactors in series, with hydrogen provided to the second (hydrogasification) reactor (and a boiler for raising steam) from shifted syngas produced in the first reactor. Coal is pulverized and is fed dry into the first reactor. The company reports that the process requires little or no external oxygen supply, that it does not depend on a catalyst in either of the reactors, and that syngas can be cleaned with conventional technology (including separation and compression of CO_2 produced from the water–gas shift reactor).

Continuous production of steam exceeding 1500°F in the hydrogen furnace is made possible by ThermoGen Hague's proprietary ceramic heat exchanger, which was developed by the company based on experience in high-temperature heat recovery in the secondary aluminum and steel industries. The company reports that other key elements of the technology have been demonstrated in other settings, including high-temperature steam gasification (by U.S. Bureau of Mines in the 1940s and 1950s) and char hydrogasification (by GTI and others in the 1970s). Development of a bench-scale reactor is pending.

Discussion

Most of the technologies profiled in this chapter are not, strictly speaking, "new." In the 1970s DOE, its predecessor the Energy Research and Development Administration (ERDA), and their laboratories (e.g., the Morgantown Energy Research Center and Pittsburgh Energy Research Center) sponsored and conducted R&D into technologies for converting coal into useful products including electricity, chemicals, and gaseous and liquid fuels. This work was quite extensive. ERDA (1975), for example, profiled 26 advanced coal-based energy technologies that were under development at that time, including processes known as "CO2 Acceptor" (dual fluidized beds with calcium oxide/calcium carbonate circulating between them), "HYGAS" (two-stage fluidized bed hydrogasification), "Synthane" (fluidized bed steam-oxygen gasification), and "U-Gas" (also fluidized bed steam-oxygen gasification), as well as molten salt, molten carbonate, and molten iron gasification processes, among others.

This early research benefitted from many millions of taxpayer dollars, and much of it led to process development units (PDUs), with typical coal feed rates of 1 to 10 tons per day, and pilot-scale projects, with typical coal feed rates on the order of a hundred tons per day. Publically-funded work continued in the 1980s and 1990s and into this decade, with the U.S. Clean Coal Technology Demonstration Program (CCTDP) and with the construction of the Power Systems Development Facility (PSDF) in Wilsonville, Alabama. The multi-billion dollar CCTDP resulted in successful commercial-scale demonstrations of IGCC technology at Polk and Wabash (and a notable failure at the Pinon Pine IGCC) and is described in more detail in Box 2.3. The PSDF, which was constructed and operated with several hundred million dollars of federal support (in addition to private sector funding), served until recently as a centralized full-system test-bed for federally-funded research on gasification and related processes. It was intended to be of sufficient scale (approximately 15 - 30 MW thermal, or roughly 50 tpd – 100 tpd, depending on the project) to bridge the gap between PDU-scale and commercial offering, with a significant emphasis in later years on the KBR gasifier and hot gas clean-up equipment (see, for example, EPRI, 2006).

While most of this work has contributed to the accumulated knowledge base for coal utilization and coal conversion, with the exception of Polk and Wabash it generally has not yet resulted in the successful demonstration of gasification technology for power generation at a pioneer plant scale (on the order of 1,000 tons per day, roughly 100 MWe) or larger commercial scale (several thousands of tons per day feed, and up). In fact, few of the many gasification technologies examined by ERDA in the 1970s, nor others like them, have entered the commercial marketplace.[2]

Most of the technologies reviewed in this chapter owe something (and in some cases quite a lot) to earlier public R&D efforts. For example, the technologies we profile:

- Use a molten bath gasification medium to enhance the gasification reactions and to provide a stable heat transfer medium; and/or,
- Use novel gasification reaction pathways promoted by higher temperatures, or catalysts, or both; and/or,
- Employ process staging as a refinement to the gasification processes; and/or,
- Build on experience in other heavy industries, such as coking and metal smelting.

Yet, at least so far, the technologies profiled in this report share the fate of much of their early cohort: none are yet deployed at a commercial scale. The central difficulty of transitioning energy technologies from RD&D to commercialization has thus earned this phase of the technology development process its own moniker: the "Valley of Death." Public funding has been sufficient to

[2] A potential exception is the U-Gas process, which, in the hands of Synthesis Energy Systems, may now be on a path to commercial deployment following recent development work in China (although not necessarily with integrated carbon capture).

Box 2.3

The Clean Coal Technology Demonstration Program

From the ashes of the U.S. Synfuels Corporation in the late 1980s rose the most successful advanced coal technology program in the U.S. to date: the Clean Coal Technology Demonstration Program (CCTDP). Motivated largely by environmental concerns (initially transcontinental acid rain) and running from federal fiscal year 1986 through federal fiscal year 2003, the CCTDP was a cost-share program designed to support technology demonstration projects with an emphasis on post-demonstration commercial viability. Performance goals were set by DOE and industry proposals solicited, and grants were then awarded to selected project to cover up to 50 percent of construction and initial project costs. Congress appropriated DOE's full contribution to each project in advance in order to provide assurance of funding, and allowances were made for some project cost growth.

Projects and outcomes supported in the power generation sub-area of CCTDP are listed in the table below.

By the end of the CCTDP, much of the electricity industry in the U.S. had been deregulated. Without power price assurance provided by regulated markets, industry participation in programs based on 50/50 construction cost-sharing had become much more challenging. Risky projects became riskier, and attention to dispatch costs and competitive position increased. Perhaps partially as a result, the similarly-structured follow-on to CCTDP – the Clean Coal Power Initiative, begun in 2001 – to date has been unsuccessful in motivating power generation demonstration projects. ■

CCTDP; Power Generation Projects

Project	Size (net)	Total Cost (DOE%/Private%)	Project Timeline Selection – Operation	Current Status
McIntosh Unit 4A PCFB	173 MWe	- (50/50)	12/89 -	Never Constructed
McIntosh Unit 4B PCFB	+103 MWe	- (50/50)	5/93 -	Never Constructed
JEA Large-Scale CFB	265 MWe	$309M (24/76)	6/89 – 4/02	Operating
Tidd PFBC	70 MWe	$190M (35/65)	7/86 – 3/91	Completed
Nucla CFB	100 MWe	$160M (11/89)	10/87 – 8/88	Completed
Kentucky Pioneer IGCC	540 MWe	- (18/82)	5/93 -	Never Constructed
Piñon Pine IGCC	99 MWe	$336M (50/50)	9/91 – 1/98	Not completed
TECO Polk IGCC	250 MWe	$303M (49/51)	12/89 – 9/96	Operating
Wabash River IGCC	262 MWe	$438M (50/50)	9/91 – 11/95	Operating
Coal-Fired Diesel Engine	6.4 MWe	$48M (50/50)	5/93 – 4/04	Not completed
Healy Boiler Project	50 MWe	$242M (48/52)	12/89 – 1/98	Not completed

Source: Compiled from DOE (2001) (see especially section 3, p. ES-2, 5-99 and 5-137).

TABLE 1 **Advantages of Advanced Gasification Technologies**

Potential Advantage	Potential Implications
Avoided or reduced need for external oxygen supply	Reduced capital cost; efficiency improvements
Feedstock flexibility; use of lower-cost feedstocks	Operating cost reductions
Improved gasification efficiency	Operating cost reductions; emissions reductions
Lower pressure operation	Capital cost reductions
Improved RAM	Capital and operating cost reductions
Modular construction	Capital cost reductions
Small scale	Niche deployment advantages

develop the basic technologies to a certain limited scale, and a policy assumption then has been made (perhaps implicitly) that market forces thereafter would pick winning technologies to advance into the marketplace. Yet the assumption has not held consistently, especially when environmental benefits are considered.

Table 1 above lists some of the potential advantages of advanced gasification technologies. These advantages could lead to significant cost savings for CCS systems. Publically available vendor estimates for four of the seven technologies listed in this chapter indicate a range of SNG production costs of $4 - $7 per million British thermal unit ("MMBtu"), for example, compared to a contemporaneous estimate of $9.25 per MMBtu for conventional gasification systems (Booz, 2008). The incremental cost of CO2 capture on top of SNG production is generally fairly small. To realize the potential benefits of advanced gasification technologies requires a significant, and sometimes risky, expenditure, however. Simply getting through the pilot-plant stage generally requires tens of millions of dollars in funding (often venture capital or other very early stage capital) for intellectual property work, process engineering, and staffing, and for designing, permitting, constructing, and operating the plant. And all of this is needed, of course, before a developer can even consider applying the technology at a pioneer-plant or commercial scale.

DOE engages with innovative gasification companies at a number of sub-commercial-scale levels, including through programs that provide financial assistance for small business R&D (e.g., the Small Business Innovation Research [SBIR] program) and more general cooperative agreements that include some measure of financial assistance. Review of DOE's current "advanced gasification" R&D projects indicates that support in several areas is on the order of several million dollars per year, but that on average (and apart from past funding for the PSDF), DOE Office of Fossil Energy external funding levels in this arena is roughly $10 million per year.[3] Cooperative Research and Development Agreements (CRADAs), under which DOE can provide technical resources (e.g., modeling and analysis, and some DOE staff and facility time) to outside parties, are also important, but do not include financial assistance.

Many of the companies surveyed here, and others, have taken advantage of these relationships in their work. Boxes 2.2 and 2.3 describe past DOE support for demonstration-scale projects. We believe that the magnitude of this support, while important, has been inadequate. Recommendations to support the commercial transition of this class of technologies are outlined below.

Figure 2 on page 30 is picture of a small commercial gasifier built by Synthesis Energy Systems in China in 2007. The 300 tpd unit produces syngas for sale to the adjacent Hai Hua methanol production facility. The SES technology is not included in this chapter as several large commercial projects are now under development based on the experience gained at Hai Hua.

[3] A list of advanced gasification projects and related project fact sheets are available at www.netl.gov/technologies/coalpower/gasification-adv-gas/index.html.

FIGURE 2 **SES 300 tpd Gasifier at Hai Hua, 2007**

Source: Image Courtesy of Synthesis Energy Systems

Recommendations

Recommendation #1

Support an Expanded RD&D Pipeline for Advanced Gasification, Beginning with Fundamental Research

This short survey by no means exhausts the list of companies and technologies currently active in the advanced gasification field. Beyond the technologies noted or described in this report, however, current levels of RD&D activity in the advanced gasification field appear to be modest at best. Abstracts accepted for the 2008 International Pittsburgh Coal Conference, for example, include few technical papers on advanced gasification technologies beyond those noted in this chapter.[4] This observation leads us to our first recommendation: Expanded federal funding should be available for the continual development and evaluation of new advanced gasification technologies at a small scale, in order to keep the RD&D pipeline "full."

It is important to recognize that no one can know with confidence whether technologies still in an early stage of development will (or will not) ultimately prove just as valuable and commercially successful as those that seem further along today. Still, funding should be provided to those technologies that pass an expert feasibility screening, not for the purpose of determining ultimate economic winners but rather to assess the basic technical soundness of different approaches. Given the potentially significant value of advanced gasification technologies to society (in terms of climate policy, energy supply, and national security), we believe that sound federal policy should seek to advance all technically-sound approaches, not just those that today appear to be "in the lead."

In support of this belief, we would note that although the companies we surveyed generally did not express any great need for additional federal support for fundamental R&D, many of them had cooperated with DOE on some aspects of their R&D. Moreover, many if not most of these companies are developing technologies that have their origins (or at least some roots) in earlier R&D efforts that benefited from outside funding, whether federal or non-federal. Presumably, energy supply and national security concerns prompted early federal R&D funding for most of these technologies. Adding today's climate concerns to traditional (and still very present) concerns that have driven past interest in gasification strikes us as making federal support for R&D in this area even more critical.

The reality is that today's relatively advanced gasification technologies stand on the shoulders of earlier R&D efforts funded by others. For this reason, we believe it is important that the federal government not neglect fundamental R&D in the coal gasification technology sector, including research in the technical foundations of coal gasification processes.

An expanded R&D program for advanced gasification will need to be centered in some new or existing federally-supported institution. Such a program might be modeled after the successful Advanced Gas Turbine Systems Research (AGTSR) Program of the 1990s, in which dozens of universities and industry formed a collaborative consortium for applied research using a highly networked "virtual national lab" environment. Universities, DOE, the National Science Foundation, the National Academy of Sciences, and the national laboratories are among several existing institutions that might be well suited to oversee this effort, but we make no definitive recommendation in this regard. The proper structure and participants for such a program can be determined as the program and its mission become better defined.

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[4] See http://www.engr.pitt.edu/pcc/2008%20Past%20Conferences.html.

Our review also indicates that many technology developers have not thoroughly evaluated the actual engineering implications (for example, detailed energy and material balances), economics, and CO2 implications (not to mention other environmental impacts) of actual commercial configurations based on their technology. Rather, they have necessarily and appropriately focused first on the core science, particularly the chemistry of their processes, and on reducing that science to practice. Conducting additional analyses is costly for small companies, and therefore difficult to justify, especially for commercial configurations that might seem superfluous during early-stage evaluations. Yet these analyses are indispensable for assessing the potential advantages and applications of these technologies and their associated costs, and for moving these technologies to market.

Given the critical need for this information, and the low cost of producing it (relative to overall U.S. energy program budgets) we recommend generous support for process engineering and related analyses — perhaps hosted within an organization such as NETL — for all technology development firms willing to engage in such evaluations. Providing assistance with standardized modeling tools would constitute a critical component of this support, because it would enable developers to know and objectively state the relative efficiency and economics of their technology. While existing programs at DOE provide some of this support through CRADAs, funding for these programs could be expanded.

Finally, shared demonstration units may be one way to increase the cost-effectiveness of public RD&D spending while also eliminating redundancies in plant buildup for technologies that incorporate similar plant components. The existing PSDF in Alabama represented a step in this direction. Its initial use focused on both pressurized fluid bed combustion and gasification system technology, but in recent years its use has generally focused on the TRIG gasifier and on the development of downstream processing equipment (e.g., hot gas filters).[5] Activity at the facility is currently being refocused as it becomes home to DOE's new National Carbon Capture Center, however, and the mission of the PSDF is moving away from gasification research.[6] Prior to this shift, expanded full-system test-bed capacity beyond the PSDF likely would have been required in order to provide timely, flexible access for smaller technology firms as they move from the bench-scale proof-of-concept stage to developing pilot-scale operating units, and then on to pre-commercial system validation. With PSDF's mission changing, this need is even more critical.

An expanded program of the type described here might require funding of roughly 50 million dollars per year for a period of 5 to 10 years, over and above current expenditures by DOE. A small fraction of this support would augment existing capacity for assessments and engineering assistance (perhaps $5 million per year for DOE staff and contractor services), while the majority of the additional funding would support construction and operation of one or more shared user facilities for advanced gasification systems development.

Recommendation #2

Establish a Self-Sustaining "First Commercial Projects" Fund

Without a doubt, the most critical problem facing new technologies is this: With few exceptions, and regardless of the other impediments to commercial deployment they may face, companies can't develop their first commercial-scale projects entirely with equity investment or debt from private sources. Public sector dollars and venture capital investments may have funded technology development from laboratory- through pilot-scale development. Private equity and project finance debt capital markets historically have been available to fund projects and manufacturing facilities once technologies are commercially proven. But few, if any, promising technologies in the gasification sector that have been proven at pilot scale are able to secure financing for commercial-scale deployment. Venture capital and private equity firms typically make smaller investments and/or require higher returns than individual energy projects typically generate, while strategic investment by large corporations can be hindered by competition for markets and/or competing funding priorities. And debt, simply put, generally isn't available for risky commercial-scale projects of any sort. (Box 2.4 provides a brief introduction to the concepts and terminology of project finance.)

[5] See "Project Accomplishments" for PSDF on the DOE web site at: http://fossil.energy.gov/fred/factsheet.

[6] See, for example, Southern Company (2007) and Southern Company (2009).

First commercial projects are not necessarily at maximum scale; often they take the form of small commercial projects (e.g., 100MWe) that can be scaled up at some later point. But even minimum size first commercial-scale projects are often too large to be financed with equity alone (even in pre-financial crisis times). All these minimum-size first commercial projects will require at least some debt, and in most cases substantial amounts of debt. Even before the current financial crisis, limited or non-recourse project debt is basically not available for first commercial projects that involve new technology and most of the companies do not have adequate balance sheets to back-stop the inherent first-mover risks.

This need for project debt, and the fact that it is unavailable, creates the well-known "Valley of Death" problem for technologies for which commercial-scale demonstration requires a facility that is sufficiently large to (1) achieve even minimal economies of scale and (2) provide adequate engineering and economic data upon which to base subsequent, fully commercial projects. This problem does not confront technologies where the first commercial project can be built at a sufficiently small scale so as not to require any debt. Advanced gasification technologies, however, almost universally need proving out at sizes that require hundreds of millions of dollars (or more) of capital. Nor is it the problem of general lack of financing for all large projects (proven technology or not) since the recent financial crisis developed. The "first commercial project" problem is specific to new technologies (whether involving gasification or other processes) where the minimum commercial-scale project is too big to be built with equity alone.

Equity investors can be persuaded to take risks, based on their own due diligence. They have the opportunity to participate in upside gains if the new technology is successful. Lenders generally cannot be persuaded to take any of the risks that equity investors take — or indeed any risks at all that they can avoid. The reason, of course, is that lenders do not participate in any upside gains even if a project is wildly successful. All the lenders get, at best, is a return of the principal amount of their loan, plus the agreed rate of interest. They are in the business of earning predictably safe, if modest, returns. They do not take risk on first commercial projects.

Most of the advanced gasification technologies we surveyed will need funding from some other source than equity investors to build their first commercial projects. One solution, of course, is to gain access to debt financing by having some third-party entity guarantee the lenders that the debt will be repaid regardless of the project's performance. Such a guarantee can come from the equity investors themselves, but in that case the guaranteed amount is really contingent equity from an investor's standpoint. This means that the project remains essentially 100 percent equity financed, from the equity investor's point of view. In terms of impacts on project costs, this means the project is not gaining any real cost benefit from using debt as part of its capital structure.

The federal government in recent years has enacted its own loan guarantee program for various energy technology projects. The program also effectively allows a direct federal loan in some circumstances.[7] There is a risk, however, that the federal loan guarantee program could be swallowed up (or exhausted) by nuclear power and renewable energy projects alone,[8] (although several legislative initiatives have been proposed that would create a stand-alone clean energy bank to oversee the loan guarantee program and add a substantial focus on first commercialization for a broad array of energy technologies). Loan guarantees for first commercialization and government support for enabling private equity investment need to be available — in significant and reliable increments — for novel coal gasification technology, not just for gasification projects that rely on established technologies and that are already capable of gaining performance guarantees from creditworthy vendors and manufacturers.

We strongly recommend, as a start, that the federal loan guarantee program (for commercial projects) be available to advanced coal gasification technologies at the development stages typical of the companies and technologies we have surveyed here. Without that availability — particularly during the current financial crisis, but (as noted above) even independent of that crisis — it will be very difficult, if not impossible, for these technologies to achieve full commercial deployment. In other

[7] Under the existing federal loan guarantee program, the Federal Financing Bank can issue direct loans for up to eighty percent of project costs at an applicant's request. See 10 C.F.R. 609.2.

[8] While the loan guarantee programs of EPAct2005 are essentially technology-neutral, allocation depends on the federal appropriations process. In 2009, more than 20 billion dollars were allocated to nuclear technologies, and more than 18 billion dollars for renewables, energy efficiency, and distributed generation. Coal programs were allocated 8 billion dollars.

Box 2.4

Project Finance

Innovation in energy systems requires construction of large initial projects, and hence "lumpy" investments of hundreds of millions of dollars or more. Like their later counterparts, these initial projects are generally constructed with some combination of equity investment (that is, money supplied by individuals and/or organizations who then own part of the project or the company developing it) and debt (that is, money that must be repaid in one way or another). Equity can come from individual investment groups or from large publically-traded corporations, and debt is generally provided either directly to the sponsoring company (for example, through general corporate borrowing or sales of corporate bonds) or by syndicates of commercial banks providing financing for development of individual projects. Acquiring this financing in the necessary quantities has proven to be a significant challenge for new technologies, since equity investors stand to gain if the project is successful, but lose if the project is not, and loans must be repaid at an agreed interest rate in any case.

A special type of debt known as "non-recourse" or "limited recourse" financing has been used extensively for project development in the oil and gas industry and has become increasingly common in the U.S. electricity industry as a result of deregulation. In these arrangements, which are currently the norm for independent power producers and for SNG manufacturing proposals, new projects are established as special-purpose companies whose assets are roughly limited to a single project under development. The project sponsors contribute some equity (perhaps 20 percent of the project costs), and commercial banks provide the balance, with recourse in the event of a default on the loans available only through the assets of the project itself. Project revenues are used to pay principal and interest on the loan and operating costs.[1]

This type of project lending does not require the participation of a large, willing corporate sponsor, but it is far riskier than corporate lending, since lenders only have one asset, rather than an entire company's earnings potential to rely upon. As a result limited recourse financing is attractive to smaller innovative organizations and yet difficult in practice to use. In fact, the project finance debt market is extraordinarily conservative on three different fronts:

- First, project finance lenders will avoid any meaningful construction risk. They thus often request a full fixed-price turnkey construction contract from a credit-worthy firm with cash penalties for delays and performance shortfalls. Lenders also request a major study from an experienced engineering firm regarding feasibility and constructability of the project. Experience has shown that these turnkey contracts and unequivocal studies are difficult to achieve for a first-of-a-kind energy plant.
- Second, project finance lenders will avoid any meaningful technology risk. Lenders often have balked at loan requests for natural gas fired combined cycle generation plants until the particular turbine model has a demonstrated multi-year successful operating history in similar applications, for example. This hurdle is a serious obstacle for the maiden voyage of a particular gasification technology.
- Third, project finance lenders prefer long-term fixed price contracts for the output of the facility executed with investment-grade rated customers. Thus new projects not only have to prove the technology to the lender but to potential "offtake" third parties, who themselves may be hesitant to enter into any definitive commitment for a first commercial project. ■

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[1] More information on loan financing can be found in Standard and Poor's (2008).

words, whatever benefits these technologies can bring to society in terms of climate policy, energy supply, and national security will not be realized unless the "Valley of Death" problem for new technologies can be overcome.

The federal loan guarantee program, however, requires large, risky advance expenditures for applicants. Even where federal appropriations cover hefty credit subsidy costs, applicants must still expend millions of dollars in preliminary engineering, site selection, offtake development, and so on — even to be able to apply. A program designed to encourage technology innovation would do well to include some form of bridge mechanism from the pilot-scale plant to the first commercial plant, even before the Valley of Death. This might be accomplished via a more flexible loan guarantee solicitation for very small commercial projects (where taxpayer risk is smaller) or other bridge mechanisms.

Federal loan guarantees are only one possible tool for helping new technologies reach the commercial deployment stage in cases where even first commercial projects must be built on a large scale. Additional policy support, such as price support for certain products, cash credits for CO_2 captured, investment and production tax credits, direct grants, and other mechanisms may all be appropriate and useful in certain instances. These forms of support can perhaps be tied to goal-based solicitations, similar to earlier CCTDP solicitations. An even broader approach, however, could make the unique "first commercial project problem" even more tractable. Since the same problem faces all new technologies (not just advanced coal gasification technologies) where the first commercial project is too large to be built with equity alone, solutions need not be confined to advanced coal gasification technologies.

As a general premise of energy technology policy, we believe that the discipline imposed by private equity and debt financing generally is necessary for the fruitful development of successful technologies (and for the elimination of uncompetitive ones). As a result, public funds generally should not be used for technology development when private funds are available. In the case of the technologies discussed in this report, however, the potential public benefits of the technologies (primarily the potential for lower-cost CO_2 reductions from fossil-fueled power generation) are likely to be realized as private-sector returns on investment only following a period of some years (perhaps even as much as a decade) under a national climate policy that puts a "price" on CO_2 emissions. Under these circumstances, where the potential returns on investment are some distance off, but the public need and potential benefit are much more immediate, substitution of public funds for private resources is essential — provided that public investment does not sacrifice the discipline of capital market forces.

To this end, the concept of a "First Commercial Project Fund" or "Clean Technology Acceleration Fund" has been a subject of study in the private financial sector for some years. Such a fund could offer targeted financial support (whether in the form of direct investment, a tranche of project debt, a loan guarantee, or other) that would suffice to enable first commercial projects involving new technologies to be built at the necessary scale. Such a fund obviously would need to attract investors. It also would need a strong technology assessment capability to assure that it provided support only to new technologies that are likely to become commercially successful with the fund's help — not to technologies that have failed to attract investment precisely because their odds of achieving commercial success are too low. And, especially in the current financial environment, such a fund will be more effective as a public-private partnership.

Again, we make no recommendation as to the institutional "home" for such a fund. Various options have been proposed. DOE or other institutions already mentioned might make appropriate homes. Alternatively, the federal government could establish a new corporate agent — perhaps patterned after the Overseas Private Investment Corporation (OPIC), which provides financial support (e.g., insurance, loan guarantees, and direct loans, and support for the creation of privately owned and managed investment funds) in response to the critical shortfall of private equity capital in developing countries.[9] Applying a similar model, a new U.S. corporation would stimulate the creation of domestically oriented, privately-owned and managed investment funds focused on providing critical equity capital that is otherwise unavailable for first commercial projects. Regardless of

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[9] OPIC typically provides debt (10–12 year maturities) to funds while earning a profit participation component. The low-cost loans provided by OPIC are backed by the full faith and credit of the U.S. government and are sold to U.S.-eligible institutional investors. For background on OPIC see Foreign Assistance Act of 1961, Section 231 et seq., as amended, available at http://www.opic.gov/.

institutional form, a "first commercial project fund" would have several important features:

- As a public-private partnership, the fund should include senior government officials as well as representatives from the private financial, technology, and energy policy communities. Federal dollars should "leverage" private dollars, not take their place, because federal dollars will go much further if they stimulate the availability of private dollars. An independent board should manage the fund according to transparent investment criteria.
- To avoid waste, the fund must have a technology assessment capability and must focus on providing only the "keystone" necessary to complete an "arch" of private equity and capital market debt for first commercial projects. The reason for this is twofold: First, this approach will make the federal dollars go further. Second, it will help weed out technologies that cannot reasonably be expected to attract sufficient capital to achieve commercial deployment even with the addition of federal support.
- In return for whatever assistance it provides, the fund should have the capability and opportunity to share in any resulting upside to the extent possible. The reasons for this are threefold. First, because taxpayers (ultimately) are the ones funding the effort, they are entitled to some form of return on the investment (just as private-sector applicants require the assistance to make money themselves). Second, government funding should never replace funding that is available in the private sector, nor should it be a cheap alternative to available private sector funding. Requiring some upside provides some assurance against either situation. Third, the fund's investments inevitably will involve some risk, which should be coupled with the possibility of some reward to enable the fund to be self-sustaining on a portfolio basis. The upside could be in the form of equity (project or corporate), profit-sharing or other form of agreement (although issues of taxation will require careful consideration). Ultimately the fund should be financially self-sustaining as returns on investments revolve to allow for continuing re-investment.

Summary

In summary, we make two recommendations. First, there is a need to ensure that improved technologies continue to pass through the development pipeline as years pass and as our ability to address carbon emissions becomes all the more critical. This means expanded support for fundamental research and a substantial public role in providing the process engineering support, assessments, and hardware development that are needed as these technologies move through the pipeline (or are discarded in favor of stronger candidates). Second, and most importantly, we recommend that a first project commercialization fund be established to help worthy technologies bridge the Valley of Death.

Implementing each of these recommendations will require at least a modest level of public funding. We estimate the cost of expanding the existing RD&D pipeline (our first recommendation) at roughly $50 million per year over and above current funding levels. The public cost of a first commercial project fund (our second recommendation) would depend on the details of its structure and implementation but would likely be serveral billion dollars. In any event, given that the coal extraction and transportation industries have much to lose as a low-carbon future unfolds, and given that advanced coal utilization technologies will be needed if coal is to be compatible with that future, those industries and the coal utility industry would seem to be a logical source for funding advanced coal utilization technology. This support might be provided voluntarily, perhaps in the form of private-sector equity or debt assurance for innovative projects. Or it might be involuntary, perhaps in the form of a levy used to fund advanced gasification RD&D and commercialization programs.[10] ■

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[10] There will, of course, be limits to what can be accomplished even with significant federal funding. As one anonymous reviewer of an early draft of this report noted: It has been my personal experience with inventor/developer led organizations that many of them falter because of internal clashes between the inventor and those who are needed to grow the developing organization to commercial demonstration and viability. These transitions are painful and often involve the transition from intuitive/empirical development to predictive design – a transition that taxes the skills and patience of many inventor-owners of the companies promoting these technologies. This transitional gap has proven to be difficult for government support to bridge.

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CHAPTER 3

An RD&D “Pipeline” for Advanced Post-Combustion CO_2 Capture Technologies

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1 Background and Motivation

More than 1500 gigawatts (GW) of coal fired power plant capacity operates today and the International Energy Administration (IEA) projects that worldwide coal power capacity will increase to more than 2600 GW by 2030 with projected emissions of about 13.5 gigatonnes[1] of CO2 annually (IEA, 2008). While some of this projected growth will likely shift to new coal power plants that include CCS, it is highly probable that the installed base of coal plants without CCS will grow to at least 2000 GW by 2020 – with a substantial fraction of this projected capacity being relatively new.

The large existing global installed coal power plant base and the rapid addition of new coal power plants in China and potentially India pose a tremendous challenge for reducing global CO2 emissions over the next several decades. Fortunately, this situation presents opportunities as well as challenges. Access to the installed U.S. coal base provides an opportunity to collect data, analyze retrofit potential, and demonstrate global leadership in CO2 reduction technology development and deployment.

There are essentially three approaches to reducing CO2 emissions from coal combustion:

- ***Burn less coal.*** In theory, this can be accomplished by both reducing demand for electricity and by substituting other fuels for coal (e.g., nuclear, renewables). In practice, reducing coal use is very difficult because coal is abundant and relatively inexpensive. Despite concerns about climate change, reliance on coal has been increasing worldwide because there has not been a viable alternative to fill the role coal plays in the world's energy systems. In fact, the rapid rise in oil prices that occurred between 2004 and 2008 increased pressure to expand the use of coal to produce chemicals and transport fuels.
- ***Improve efficiency of coal-fired power plants.*** There are real opportunities for efficiency improvements at most conventional coal plants. However, even if these options were aggressively pursued, they would — at best — only reduce emissions by 10 to 20 percent (Beer, 2007). This would be a positive step, but it falls short of advancing progress toward a near-zero emission coal-fired power plant, which may be required by future carbon policy.
- ***Capture and store the CO2.*** Carbon dioxide capture and storage (CCS) is the only pathway that can allow the world to continue to enjoy the benefits of using coal while drastically reducing the emissions associated with coal combustion. At a minimum, CCS can be a bridging strategy to provide time for developing alternatives to coal.

This chapter addresses CCS as this technology is essential to the deep reductions in CO2 emissions needed by mid-century to address climate change. In particular, it looks at a set of technologies termed "post-combustion CO2 capture." The focus is on applications to coal-fired power plants because such plants constitute by far the largest source of CO2 emissions appropriate for CCS (IPCC, 2005). However, it should be noted that certain industrial processes (natural gas processing, ammonia production, cement manufacture, and more), as well as natural gas-fired power plants are also amenable to CCS.

At a coal-fired power plant, CO2 is a component of the flue gas. The total pressure of the flue gas is typically 1 atmosphere (atm)[2] and the CO2 concentration is typically 10-15 percent. The process of separating a relatively pure stream of CO2 from this low-pressure, low-CO2-concentration mix of flue gases is referred to as post-combustion CO2 capture. The capture step is typically followed by a compression step, where, for ease of transport (usually by pipeline) and storage, the CO2 is compressed to 100 atm or more.

The idea of separating and capturing CO2 from the flue gas of power plants did not originate out of concern about climate change. Rather, it first gained attention as a possible inexpensive source of CO2, especially for use in enhanced oil recovery (EOR) operations where CO2 is injected into oil reservoirs to increase the mobility of the oil and thereby the productivity of the reservoir. Several commercial plants that capture CO2 from a power plant flue gas were constructed in the United States in the late 1970s and early 1980s. When the price of oil dropped in the mid-1980s, the recovered CO2 was too expensive for EOR operations, forcing the closure of these capture facilities. However, the Searles Valley Minerals Plant in Trona, California, which uses post-combustion capture to produce CO2 for the carbonation of brine, started operation in 1978 and is still

Photo on page 37.

Amine-based CO_2 capture system in Trona, California

This system captures approximately 900 tons of CO_2 per day from the exhaust gas of a coal-fired boiler used for electricity generation and process heating. CO_2 is used in the production of soda ash. Operating since 1978, it is the largest coal PCC system in the world.

Image courtesy of Searles Valley Minerals

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[1] One gigatonne is one billion metric tons, where a metric ton – also called a "tonne" – is 1,000 kilograms ("kg").

[2] One atmosphere is the pressure exerted at sea level by the Earth's atmosphere (14.7 pounds per square inch).

operating today. Several more CO_2 capture plants were subsequently built to produce CO_2 for commercial applications and other markets.

All the above plants used post-combustion capture technology. They range in size from a few hundred tons of CO_2 a day to just over 1,000 tons a day (Herzog, 1999). Deployment of post-combustion capture technologies for climate change purposes will entail very substantial increases in scale, since a 500 MW coal-fired plant produces about 10,000 tons of CO_2 per day.

There are two major alternatives to post combustion capture for capturing CO_2 from coal power generation:

- ***Oxy-combustion capture.*** Because nitrogen is the major component of flue gas in power plants that burn coal in air (as nearly all existing plants do) post-combustion capture is essentially an exercise in nitrogen–carbon dioxide separation. If there were no nitrogen, CO_2 capture from flue gas would be greatly simplified. This is the thinking behind oxy-combustion capture: Instead of air, the power plant uses a high purity (95 percent or above) oxygen stream to combust the coal. The on-site production of oxygen in an air separation plant represents the largest cost component in the capture process.
- ***Pre-combustion capture.*** As the name implies, this refers to the capture of CO_2 prior to combustion. Pre-combustion capture is *not* an option at the pulverized coal (PC) power plants that comprise most of the existing coal capacity base. However, it is an option for integrated coal gasification combined cycle (IGCC) plants. In these plants, coal is first gasified to form synthesis gas (or syngas) that is chiefly composed of carbon monoxide (CO) and hydrogen (H_2). The syngas then undergoes a water–gas shift, in which the CO reacts with steam to form CO_2 and additional H_2. The CO_2 is then removed, and the hydrogen is diluted with nitrogen and fed into a gas turbine combined cycle. The advantage of this approach is that it is much less expensive than the post-combustion capture process. The disadvantages are that there are only a few IGCC plants in the existing coal fleet and IGCC plants may be more expensive than PC plants when the costs of CO_2 capture are not included.

Post-combustion capture is important because:

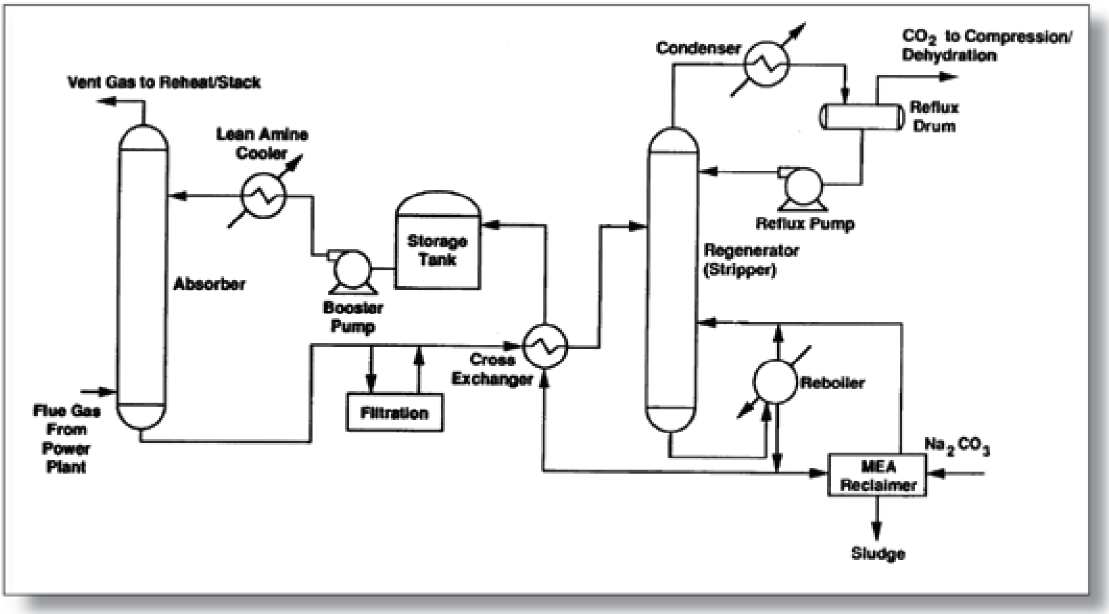
- It is compatible with — and can be retrofitted to — existing coal-fired power plants without requiring substantial changes in basic combustion technology.
- It is the leading candidate for gas-fired power plants. Neither the oxy-combustion nor the pre-combustion approaches are well suited for gas plants.
- It offers flexibility. If the capture plant shuts down, the power plant can still operate. The other two capture options are highly integrated with the power plant so if capture systems fail, the entire plant must shut down. Furthermore, post-combustion capture offers utilities (and regulatory commissions) the option to allow for increased capacity by temporarily curtailing the capture process during periods of peak power demand.

For the reasons discussed above, this chapter focuses on near-term as well as advanced post-combustion capture technologies that could be applied both to new coal power plants and to retrofit existing ones. Specific engineering considerations that apply in the retrofit context, however, such as steam cycle and steam turbine changes, are outside the scope of this chapter (though they are generally considered manageable). Although this chapter focuses on applications to coal power, generally speaking the technologies covered here would also be applicable to natural gas power plants. Section 2 of the chapter reviews the current state of post-combustion capture technology. Current R&D priorities are presented in Section 3, while Section 4 focuses on advanced R&D pathways. Finally, Section 5 presents research, development, and demonstration ("RD&D") recommendations.

2 Current Status of Post-Combustion Capture

To date, all commercial post-combustion CO_2 capture plants have used chemical absorption processes with monoethanolamine (MEA)-based solvents. MEA was developed over 70 years ago as a general, non-selective solvent to remove acid gases, such as CO_2 and hydrogen sulfide, from natural gas streams. The process was modified to incorporate inhibitors that reduce solvent degrada-

FIGURE 1 **Process Flow Diagram for the Amine Separation Process**



tion and equipment corrosion when applied to CO2 capture from flue gas. Concerns about degradation and corrosion also kept the solvent strength relatively low (typically 20-30 percent amines by weight in water). This results in relatively large equipment sizes and solvent regeneration costs.

As shown in Figure 1, which depicts a typical process flow for post-combustion capture, flue gas contacts MEA solution in an absorber. The MEA selectively absorbs the CO2 and is then sent to a stripper. In the stripper, the CO2-rich MEA solution is heated to release almost pure CO2. The CO2-lean MEA solution is then recycled to the absorber.

2.1 Cost of Capture

Table 1 shows representative costs for a supercritical, pulverized coal (SCPC) power plant,[3] with and without capture based on a modern amine system. Note that the costs include both capture and compression, but exclude the transport and storage of captured CO2. These numbers vary over time and location and do not represent any particular power plant facility. Their primary purpose is to illustrate the relative costs of power production with and without CO2 capture.

The first thing to note is that when a capture and compression system is added, the plant's overall thermal efficiency (the fraction of the energy released by combustion of the fuel that is transformed into electricity) drops from 38.5 percent to 29.3 percent. This translates to a *relative* reduction in thermal efficiency of 24 percent. The efficiency loss is caused by the additional parasitic energy load from the CO2 capture system. This parasitic load can be broken down into three components:

- Extraction of steam from the plant's electricity-generating turbine to the stripper reboiler accounts for more than 60 percent of the energy required by the capture system. The steam provides energy to break the chemical bonds between the CO2 and the amine; supplies the heat required to raise the temperature of the amine solution to the operating temperature of the stripper, and sweeps away the released CO2.
- Electricity to drive the CO2 compressors accounts for about one third of the energy load from the capture system.
- Electricity to drive the blowers to push the flue gas through the absorber accounts for roughly 5 percent.

The drop in thermal efficiency caused by adding a post-combustion capture system has multiple effects on plant cost. First, 30 percent more coal must be burned to produce the same amount of electricity.[4] More importantly, as indicated in Table 1, the capital cost of the plant (in $/kW) increases by 61 percent. This is because the cost of the amine absorption process, compressors, and

[3] Current state-of-the-art supercritical plants operate at 24.3 MPa (3530 psi) and 565°C (1050°F) (MIT, 2007).

[4] Increased fuel consumption would also raise variable operating cost, which could reduce the dispatch factor for the plant. This potentially important impact is ignored in this analysis.

TABLE 1

Updated Capture (Including Compression) Costs for Nth Plant SCPC Generation[5]

(Hamilton *et al.*, 2008)

	Reference Plant	**Units**	**SCPC**
	Total Plant Cost	$/kWe	1910
	CO_2 Emitted	Kg/kWh	0.830
	Heat Rate (HHV)	Btu/kWh	8868
	Thermal Efficiency (HHV)		38.5%
LCOE	Capital	$/MWh	38.8
	Fuel	$/MWh	15.9
	O&M	$/MWh	8.0
	Total	$/MWh	62.6
	CO_2 Capture Plant		
	Total Plant Cost	$/kWe	3080
	CO_2 Emitted @ 90% Capture	kg/kWh	0.109
	Heat Rate (Hhv)	Btu/kWh	11652
	Thermal Efficiency (Hhv)		29.3%
LCOE	Capital	$/MWh	62.4
	Fuel	$/MWh	20.9
	O&M	$/MWh	17.0
	Total	$/MWh	100.3
	$/tonne CO_2 avoided		
	vs. SCPC	$/metric ton	52.2

other capture equipment increases the required capital investment by 22 percent, or a factor of 1.22, while electrical output decreases by 24 percent or a factor of 0.76; thus, the investment cost expressed in $/kW increases by a factor of 1.22 divided by 0.76 or 1.61. In other words, parasitic energy drain translates into the consumption of more coal per kWh *and* an increase in capital costs beyond the purchase price of additional equipment. Because of the magnitude of this effect, a *key goal of research in post-combustion capture is to reduce the parasitic energy load.*

Table 1 reports the mitigation or avoided cost in $ per metric ton of CO2 avoided. Because of the parasitic energy requirement, the number of tons avoided is always less than the number captured. As a result, the cost per ton avoided is also always greater than the cost per ton captured. This is shown graphically in Figure 2 on page 42. The top bar shows the amount of CO2 emitted per kWh from a reference plant without capture. The lower bar shows the amounts of CO2 emitted and captured per kWh from the same power plant with 90 percent CO2 capture, including compression. Because of the parasitic energy requirement, more CO2 is produced *per kWh* in the capture plant. The amount of CO2 avoided is simply the difference in emissions between the reference plant and the plant with capture.

The mitigation cost in $ per metric ton CO2 avoided is particularly significant because it is the quantity against which the permit or allowance price under a cap-and-trade system should be compared. As indicated in Table 1, the mitigation costs for the capture plant come to about $52 per metric ton of CO2 avoided. Typically, transport and storage add about $10 more, making the total CCS mitigation cost around $62 per metric ton of CO2 avoided. The latter figure suggests the magnitude of the cap-and-trade permit price that is required to make CCS commercially viable, assuming current technology and no other policy incentives. Actual costs for first-of-a-kind post-combustion capture installations, especially retrofits, will likely be significantly higher than these estimates.

2.2 Potential for Reducing the Parasitic Energy Loss

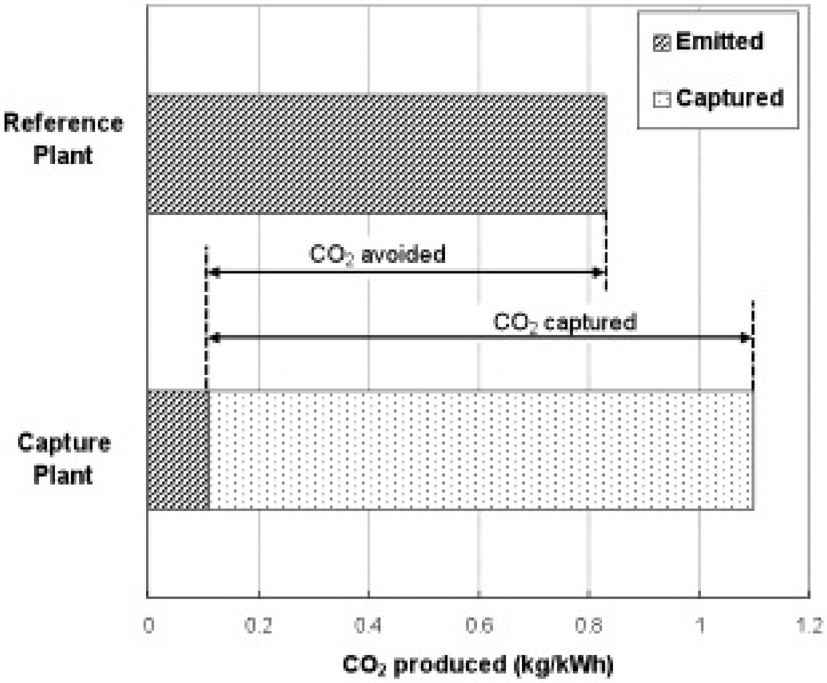
As noted above, the parasitic energy loss for capture and compression with current post-combustion capture technology is 24 percent.

[5] This cost assumes: 2007$, Nth plant (i.e., ignores first mover costs), 90 percent capture, 85 percent capacity factor, bituminous coal (Illinois #6); it does not include transport and storage costs and it assumes (1) today's technology (i.e., no technological breakthroughs required); (2) regulatory issues resolved without imposing significant new burdens; and (3) operations at scale (i.e., 500 MW_e net output before capture). LCOE is levelized cost of electricity.

FIGURE 2

Graphical Representation of Avoided Co_2

The avoided emissions are simply the difference between the actual emissions per kWh of the two plants. Note that due to the parasitic energy requirement (and its associated additional CO_2 production), the amount of emissions avoided is always less than the amount of CO_2 captured.



About one-third of this loss (8 percent) is due to compression, with the rest (16 percent) attributable to separation. A key question is how much improvement is possible. A rough "minimum work" calculation can be used to answer this question (the methodology is outlined in Appendix A to this chapter). The results of this calculation indicate that the minimum energy requirements for separation and compression are as follows:

- for separation (assuming 90 percent capture) = 43 kWh per tonne (kWh/t) CO2 captured
- for compression = 61 kWh/t CO2 compressed

By comparison, a typical SCPC power plant without carbon capture produces 1 metric ton of CO2 for every 1200 kWh of net power generated. It follows that the *minimum* energy requirement for separation (as a percentage of net power production) is 3.2 percent ([43 kWh/t CO2 captured] x [9t captured/10t produced] / [1200 kWh/t CO2 produced]). The estimated *actual* parasitic load (16 percent) is five times that. By comparison, the estimated minimum energy requirement for compression is 4.6 percent ([61 kWh/t] x [9t/10t] / [1200 kWh/t]). The estimated actual parasitic load (8 percent) is less than two times that. This suggests that there is considerably more room to improve the efficiency of the separation process than there is to improve the compression process.

In a typical SCPC power plant without capture, only 38.5 percent of the energy released by burning the fuel is transformed into electricity — in other words, the "first law efficiency" is 38.5 percent. The remaining 61.5 percent can be considered waste heat. Use of some of that waste heat to drive CO2 capture can reduce parasitic power consumption. For example, without the use of waste heat, the parasitic load for separation would be about double the 16 percent stated above. Estimating the maximum extent to which a given plant's waste heat can be applied to CO2 recovery requires a more complex analysis than the one outlined in Appendix A (specifically, it requires an "exergy" analysis of an integrated power plant/CO2 capture system).

2.3 Commercial vendors

Two processes for post-combustion capture were developed in the 1970s, when a commercial market emerged for CO2 (mainly for use in enhanced oil recovery – EOR). One was developed by Kerr-McGee, the other by Dow Chemical. The Kerr-McGee process was based on a 20 percent MEA solution and was used primarily with coal-fired boilers (Barchas and Davis, 1992). The Dow process used a 30 percent MEA solution and was applied primarily on natural gas plants (Sander and Mariz, 1992). Today, the Dow technology (ECONAMINE FG) is licensed by Fluor and the Kerr-McGee technology by ABB/Lummus. Several installations worldwide use these technologies.

Several other vendors also offer commercial amine processes:

- MHI in Japan has developed a process named KM-CDR that is based on the proprietary solvent KS-1 (the solvent probably involves a hindered amine). The KM-CDR process is being offered commercially for gas-fired plants (with an offering for coal-fired plants under development). MHI claims their process is the most energy efficient of current commercial offerings. Four commercial units for gas-fired plants have been built with this technology, with four more under construction. Pilot scale tests of the KM-CDR process are currently being conducted on coal-fired flue gas (Kishimoto *et al.*, 2008).
- **HTC Purenergy** is offering a process package. It is based on research done at the International Test Centre at the University of Regina to develop a mixed amine solvent. One way the company is attempting to lower costs is by offering modular units that can be pre-fabricated. HTC Purenergy has a unique marketing strategy that involves financing, constructing, and managing the capture process. The company also offers an option in which they (HTC) own and operate the process.
- **Aker Clean Carbon** in Norway also offers a commercial package. Named "Just Catch", development of this process was initiated by Aker Clean Carbon AS with support from a larger industrial consortium (Sanden *et al.*, 2006). The aim was to develop and verify an amine based technology in a cost efficient manner. Preliminary results for this process are based on a set of feasible technology improvements where the further engineering design is performed with the principal goal of facilitating cost-effective solutions, minimizing technical and economic risks, and developing confidence in cost estimation.
- **Cansolv** is offering a CO2 capture process based on a recently developed amine system that uses a proprietary solvent named Absorbent DC101™ (Cansolv, 2008). The solvent is based on tertiary amines and probably includes a promoter to yield sufficient absorption rates to be used for low-pressure flue gas streams (Hakka and Ouimet, 2006). With the use of oxidation inhibitors this process can be applied to oxidizing environments and in environments with limited concentrations of oxidized sulfur. The claim is that this process can also simultaneously remove other acidic contaminants and particulate material, such as oxides of sulfur and nitrogen (SOx, and NOx). Two demonstration plants using the Cansolv CO2 capture system have been built. One is in Montreal, Canada and captures CO2 from the flue gas of a natural gas fired boiler; the other is in Virginia and captures CO2 from flue gas of a coal fired boiler. No commercial plants have yet been built.

3 Current R&D Thrusts

Figure 3 on page 44 outlines the various technology pathways to post-combustion capture. Most of these pathways are discussed in this section; the exploratory technologies are reviewed in Section 4.

3.1 Absorption

In absorption (or "scrubbing"), flue gas comes in contact with a liquid "absorbent" (or solvent) that has been selected because CO2 dissolves in it more readily than nitrogen — i.e., it is *selective* for CO2. The process takes place in tall columns (towers) known as scrubbers, in which turbulent flow promotes rapid CO2 transfer from gas to liquid. Differences in density make it easy to separate the emerging gas and liquid.

To recover the captured CO2 the loaded solvent is pumped to a "stripper" in which it is exposed to a hotter gas that is free of CO2 — typically steam. Heating the solvent causes desorption of the CO2 (and traces of nitrogen). The stripped liquid is pumped back to the scrubber, while the steam/CO2 mixture is cooled to condense the steam. This leaves high-purity CO2 suitable for compression, transport, and sequestration.

The *capital* costs of scrubbing decrease as the *rates* of CO2 absorption/stripping ("mass transfer") increase. This is mainly because smaller absorbers and strippers, with correspondingly

FIGURE 3 **Flue Gas R&D Pathways**

ABSORPTION
Mea, other alkanolamines
Blended alkanolamines
Piperazine
Mea/Piperazine
K2CO3/Piperazine
Less corrosive amines
Less degradable amines
Low Δhrxn amines
Chilled Ammonia
Nonaqueous solvents

REACTIVE SOLIDS
CaO
Na_2CO_3
NaOH/CaO
Li_2O/Li_2ZrO_3
Li_4SiO_4

ADSORPTION
ZEOLITES
5A, 13x, MCM-41

CARBON, SILICA,
ALUMINA
Amine-doped
Potassium salt-doped

MEMBRANES
Gas/Liquid Contactors
Permselective and high-temperature Polymers

BIOLOGICAL
Algae (photosynthesis)
Carbonic anhydrase (enzyme-catalyzed
CO2 hydrolysis)

EXPLORATORY ADSORPTION
on self-assembling organic nanochannels,
& metal/organic frameworks

ABSORPTION
by polyamines, ionic liquids

shorter gas/liquid exposure times, are required when CO2 transfer rates are higher. Smaller scrubbers and strippers also mean lower *operating* costs because less electrical energy is required for blowers and pumps to drive gas and liquid through the system. However, the principal operating expense is for the energy consumed as heat — primarily to generate steam, but also to warm the loaded solvent.

Water itself is much more soluble to CO2 than to nitrogen (N2). However, its *capacity* for CO2 is still so low that capturing industrial-scale amounts of CO2 would require the circulation of prohibitively large quantities of water. *Organic* solvents offer greater solubility to CO2 and are therefore widely deployed in capture systems, especially to recover CO2 from high-pressure mixtures such as natural gas. However, the near-atmospheric pressures characteristic of flue gas from coal-fired power plants favor the use of aqueous chemical solutions that *react reversibly* with dissolved CO2 — i.e., that combine with CO2 in the scrubber and release it at the higher temperatures in the stripper.

Early systems for recovering CO2 from industrial gas streams employed hot potassium carbonate solutions that react with dissolved CO2 to form potassium bicarbonate. However, for many decades now the additives of choice have been *amines* (Kohl and Nielsen, 1997).

3.1.1 Amines

Amines are water-soluble organic chemicals that contain reactive nitrogen atoms. As noted earlier, the workhorse amine in most current CO2 separation systems is *monoethanolamine* (MEA). Many other amines and, especially in recent years, amine blends such as MEA plus methyldiethanolamine (MDEA), have also been utilized.

Amines react rapidly, selectively, and reversibly with CO2 and are relatively nonvolatile and inexpensive. However, they are corrosive and so require more expensive materials to be used in construction. In addition, they do gradually volatilize (this can be especially problematic in the case of MEA) and they do degrade, especially in the presence of oxygen and/or sulfur dioxide. Both of these phenomena necessitate the timely injection of fresh solution.

The considerable amounts of thermal energy required to strip CO2 from loaded MEA solutions are an acceptable expense when the CO2-purged gas is valuable. However, as emphasized earlier, when MEA is applied to purify flue gas in conventional absorber/stripper systems, the parasitic energy consumption is considerable. Table 1 on page 41 indicates that the combined costs of CO2 capture and compression raise the price of generating electrical power by more than 60 percent. Reducing that cost penalty is a primary goal of R&D activity, much of which has focused on exploring the performance of alternative reactants, including amines other than MEA (Bonenfant *et al.*, 2003). The results have been encouraging.

For example, *sterically hindered* amines have been developed that bind more CO2 per molecule than MEA (Sartori and Savage, 1983). However, the energy savings relative to MEA are partially offset by increased capital costs because the lower absorption rates of these amines necessitate larger scrubbing equipment. Alternatively, MEA has been blended — either with amines that are less corrosive and require less steam to regenerate

(Aroonwilas and Veawab, 2004) or with the additive piperazine (PZ), which has limited solubility in water and is more volatile than MEA, but which markedly accelerates CO2 absorption and allows for the use of lower MEA concentrations (Dang and Rochelle, 2003).

Recent computer simulations indicate that alternative *design configurations*, including use of MEA+PZ and MDEA+PZ at different pressure levels, can reduce energy requirements for CO2 capture and compression systems to 20 percent of power plant output (Jassim and Rochelle, 2006; Oyenekan and Rochelle, 2007).

3.1.2 Ammonia

Ammonia-based solutions offer possibilities for developing absorption processes based on less corrosive and more stable solvents. At the same time, since ammonia is a toxic gas, prevention of ammonia "slip" to the atmosphere is a necessity. Despite this disadvantage, a decade-old report of superior CO2 capture performance (Bai and Yeh, 1997) has drawn considerable attention to aqueous ammonia (AA) solutions. The CO2 uptake per kilogram of ammonia is estimated to be three times that per kilogram of MEA (Yeh and Bai, 1999).

Furthermore, a recent economic study (Ciferno *et al.*, 2005) notes that the amount of steam required to regenerate AA (per kilogram of captured CO2) is one-third that required with MEA (see also Resnik *et al.*, 2004). The same study estimates that operating and capital costs for capture systems that use AA are, respectively, 15 percent and 20 percent less than with MEA. This reduces the projected cost of CO2 capture and compression to 18-21 percent of the total cost of electrical power production, which is comparable to the cost reduction obtainable by optimizing the configuration of a PZ-based absorption process.

Ammonia-based systems operate efficiently at temperatures lower than those required for conventional MEA-based scrubber systems. The lower temperatures also minimize ammonia volatility and the potential for slippage. The chemistry is for the most part analogous to that in potassium carbonate solutions, except that the ammonium ion replaces the potassium ion (thus, dissolved ammonium carbonate reacts with CO2 to form ammonium bicarbonate). However, at the very low absorber temperatures (0^{o}C to10^{o}C) characteristic of the chilled ammonia process (CAP), ammonium bicarbonate precipitates as a solid, which requires different handling.

Because the absorption reaction is reversible at lower temperatures than with amine-based solvents, low-quality waste heat available at power plants may be more thoroughly exploited to release captured CO2 in the strippers of ammonia-based systems.

A further, potentially exploitable advantage is that — unlike MEA, which is degraded by sulfur dioxide (SO2) — ammonium carbonate reacts with SO2 to form ammonium sulfate and with NOx to form ammonium nitrate, both of which are marketable as fertilizers. Thus, ammonia-based CO2 capture may be carried out either separately from, or in conjunction with, the scrubbing of SOx and NOx.

In a demonstration facility that is scheduled to start up in 2011, Powerspan is planning to capture CO2 from the flue gas of a 120 MW power plant flue using an AA system that will be constructed downstream of AA-based SOx/NOx control equipment (McLarnon, 2007). Powerspan is currently operating a pilot facility at FirstEnergy's R.E. Burger plant that is capturing 20 tons of CO2 per day. Similarly, Alstom Power is testing a 35 ton-per-day CAP-based CO2 capture system at the We Energies Pleasant Prairie Power Plant.

There will be great interest in the extent to which laboratory and pilot-scale successes — including capture and recycle of the toxic ammonia vapor generated in the stripper — can be replicated on an industrial scale. In the meantime, researchers are actively investigating techniques for further improving AA performance, including techniques that use additives to reduce evaporative ammonia losses without sacrificing CO2 capture performance (You *et al.*, 2008).

3.2 Adsorption

3.2.1 Physical Sorbents

CO2 may be recovered from flue gas with a variety of nonreactive sorbents including carbonaceous materials and crystalline materials known as zeolites. High porosities endow activated carbon and charcoal with CO2 capture capacities of 10 to 15 percent by weight. However, their CO2/N2 selectivities (*ca.* 10) are relatively low. Because of this disadvantage, projected capture costs (including compression) are such that carbon-based systems become practical only when the required CO2 purity is at most 90 percent (Radosz *et al.*, 2008). Zeolitic materials, on the other hand, offer CO2/N2 selectivities five to ten times greater than those of carbonaceous materials. However, their CO2 capacities are two to three times lower (Konduru *et al.*, 2007; Merel *et al.*, 2008). Moreover, zeolite performance is impaired when water vapor is present.

To be competitive with liquid solvents, solid sorbents must be less sensitive to steam and offer substantially greater capacities and selectivities for CO2 than currently available physical sorbents (Ho *et al.*, in press).

3.2.2 Chemical Sorbents

When heated to 850°C, limestone — or calcium carbonate (CaCO3) — releases CO2 (calcines) and thereby transforms to calcium oxide (CaO). CaO will recombine with CO2 at 650°C. These reactions have a long history of service in industrial processes. Limestone is also widely employed to capture flue gas SO2. However, it loses capacity over time, especially if it is deployed to capture *both* CO2 and SO2, and requires frequent replacement (Rodriguez *et al.*, 2008).

The CaO/CaCO3 system nonetheless remains attractive because of its high CO2 capture capacity and long track record. Furthermore, it offers possibilities for power plant configurations that (a) maximize the benefits of feeding otherwise prohibitively expensive oxygen rather than air (thereby obviating the need for post-combustion CO2/N2 separation), (b) exploit the availability of high-level heat, and (c) improve energy efficiency by generating steam from heat released in the carbonation reaction (Manovic and Anthony, 2008; Romeo *et al.*, 2008). Consequently, CaO/CaCO3-based CO2 capture is the focus of continuing intensive research activity.

Alkali metal-based sorbents also capture CO2 — primarily via reactions that transform metal carbonates into bicarbonates, with steam as a co-reactant (similar to when CO2 reacts with aqueous carbonate solutions). Highly porous sodium-based sorbents operate efficiently in the same temperature range as aqueous amines (25°C-120°C), but have considerably lower CO2 capture capacity (Lee *et al.*, 2008). Lithium-based sorbents that function best at 400°C-500°C offer higher CO2 capacities (Venegas *et al.*, 2007; Ochoa-Fernandez *et al.*, 2008). The long-term stability and performance of alkali metal-based sorbents under actual flue gas conditions remains to be established.

An increasingly active area of research involves CO2 capture by *amines immobilized within porous sorbents*. In fact, a practical system of this type has been deployed for CO2 capture in a space mission life support system (Satyapal *et al.*, 2001). A variety of amines, sorbent supports, and immobilizing techniques have been tested (Gray *et al.*, 2005; Knowles *et al.*, 2006; Hicks *et al.*, 2008; Yue *et al.*, 2008) and the results have been quite promising. Several amine-derived sorbents exhibit high CO2 uptake/release capacity and stability in the 50°C–120°C range. Furthermore, the absence of large quantities of circulating water should make thermal energy requirements for CO2 release appreciably lower than for amine-based absorption/stripping. As noted above regarding alkali metal-based sorbents, commercial viability requires that these sorbents can be shown to operate stably for extended periods of time under actual flue gas conditions.

3.3 Membrane-Based Separation

A third mature technology under consideration for CO2 capture is membrane-based separation. Membranes, which generally consist of thin polymeric films, owe their selectivities to the relative rates at which chemical species permeate. Differences in permeation rates are generally due (in the case of *porous* membranes) to the relative sizes of the permeating molecules or (in the case of dense membranes) their solubilities and/or diffusion coefficients (i.e., mobilities) in the membrane material. Because permeation rates vary inversely with membrane thickness, membranes are made to be as thin as possible without compromising mechanical strength (which is frequently provided by non-selective, porous support layers).

As is true of membrane-based filtration and desalting of water, membrane-based gas separation is a well-established, mature technology. Many large plants are operating worldwide to recover oxygen and/or nitrogen from air, CO2 from natural gas, and hydrogen from a variety of process streams. As is the case with absorption and adsorption, economic considerations dictate that membrane systems recover CO2 from flue gas selectively.

Membrane permeation is generally pressure-driven: The feed gas is either compressed, and/or the permeate channel operates under vacuum, and/or a sweep gas is employed. Due to the low partial pressure of CO2 in the flue gas, this constitutes a major challenge for membrane-based capture systems compared to systems that make use of liquid absorbents or solid adsorbents that are thermally regenerated (i.e., heated to strip away the captured CO2).

3.3.1 Polymeric Membranes

Recently, Favre and coworkers (Bounaeur *et al.*, 2006; Favre, 2007) and Wiley and coworkers (Ho *et al.*, 2006, 2008) published the results of extensive calculations that explore the dependence of CO2 capture costs on membrane selectivity, permeability, and unit price. Most significantly, their results indicate that for membranes to be competitive with amine-based absorption for capturing CO2 from flue gases, their CO2/N2 selectivities (i.e., permeability ratios) must be in the 200 range.

With rare exception, the selectivities of available polymers fall well below that. While many have selectivities of 50 to 60, they tend to be less permeable — i.e., their fluxes are low (Powell and Qiao, 2006). Once again, cost effectiveness may be achievable only when separation is promoted by a CO2-selective chemical reaction.

Ho and coworkers (Zou and Ho, 2006; Huang *et al.*, 2008) have demonstrated that by virtue of their reversible reactions with CO2, amines can raise the CO2/N2 selectivity of polymeric membranes to 170 while also boosting CO2 fluxes. If these encouraging results can be sustained for extended periods of operation, such systems will merit serious consideration as candidates for CO2 capture at coal-fired power plants.

3.4 Membrane Absorption

An alternative approach to CO2 capture is to use porous membranes as *platforms for absorption and stripping*. In this approach, which has attracted considerable interest, membranes serve primarily to separate gas and liquid. CO2 and N2 each transfer easily through nonselective, gas-filled membrane pores. Selectivity is provided by the liquid, which, as usual, is typically an aqueous amine solution (deMontigny *et al.*, 2006; Shimada *et al.*, 2006). One advantage of membrane absorbers is that, unlike conventional absorbers, there are no inherent restrictions on gas and liquid flowrates.

The performance of membrane absorbers, when measured in terms of mass transfer rates per unit module volume, can exceed those of absorption and stripping in conventional columns. Furthermore, modularity makes membrane systems easy to replace or expand. However, economies of scale do not apply to modular systems, whereas they do favor traditional, large absorption and stripping columns.

3.5 Biomimetic Approaches

In addition to absorption, adsorption, and membrane-based systems, a wide variety of new approaches are under development. Some that have shown promise take their cues from living systems that have evolved highly efficient systems for capturing and/or converting CO2.

For example, several studies have explored the use of the enzyme carbonic anhydrase, which is the most efficient catalyst of CO2 reaction with water, to promote CO2 scrubbing from flue gases (Bond *et al.*, 2001). By immobilizing carbonic anhydrase in a bioreactor, Bhattacharya *et al.* (2004) quadrupled the rate of CO2 absorption in water.

Microalgae systems, which have long been under investigation for CO2 capture from air (Cheng *et al.*, 2006), are especially attractive because they consume CO2 in photosynthesis. This obviates the need for CO2 compression and sequestration. Furthermore, the algae biomass can serve as animal feed or as an effectively carbon-neutral fuel (Skjanes *et al.*, 2007).

3.6 Other Approaches

Another approach that has been proposed is to cool the flue gas to low temperatures so that the CO2 is separated as dry ice (Younes *et al.*, 2006). After the initial paper outlining this concept, no further information has been forthcoming.

4 Advanced R&D Pathways

Current technologies for recovering and separating CO2 and other compounds from gas streams are relatively mature. As discussed in the previous section, these technologies can be broadly classified into three categories: absorption, adsorption, and membrane processes. In almost all absorption and adsorption processes, the separation step entails physical and/or chemical interactions that form new molecular complexes. This step must then be reversed through significant increases in temperature. The need to heat and subsequently cool large volumes of sorbents to prepare them for the next sorption cycle is wasteful both thermodynamically (because it involves unnecessary heating and cooling of inert materials) and dynamically (a large thermal mass of inert materials limits heat transfer rates, which leads to larger required equipment sizes).

While the performance of currently available technologies can be expected to improve with further R&D, new concepts and materials could provide significant breakthroughs in the performance and costs of capture systems. Advanced R&D pathways seek to eliminate or at least minimize large thermal swings through a greater reliance on structured materials; possibly stimuli-responsive, entropic (e.g., shape selective) rather than enthalpic interactions between the sorbate and the separation media; and through the application of stimuli (e.g., an electric field) to modify the separation environment in order to release the captured solute. Some of these promising new approaches are reviewed in this section.

4.1 Solid Adsorbents

The traditional use of carbonaceous materials for CO2 adsorption is limited by low CO2/N2 selectivities and while the more structured zeolites have significantly higher selectivities, they have significantly lower capacities. In addition, their performance is impaired when water vapor is present. Advanced research in the development of new adsorbent materials indicates some promising approaches that may overcome many of the limitations of the currently available adsorbents. Some of these approaches are discussed here.

4.1.1 Metal-Organic Frameworks

Metal organic frameworks (MOFs) are porous crystalline solid materials with well-defined cavities that resemble those of zeolites (Millward and Yaghi, 2005; Bourelly *et al.*, 2005; Mueller *et al.*, 2006). They can be tuned to vary the cavity size, accessibility, and interactions with molecules contained within the cavity. MOFs are open structures with high capacities for gaseous species and have good diffusional properties. They may not always be sufficiently stable for the conditions under which they would need to be applied in flue gas treatment, however. More recently, nanosystems researchers at UCLA (Banerjee *et al.*, 2008; Wang *et al.*, 2008) have synthesized and screened a large number of zeolitic-type materials known as zeolitic imidazolate frameworks (ZIFs). A few of the ZIFs have been shown to have good chemical and thermal stability in water and in a number of different organic solvents, an advantage over traditional silicon-based zeolites, whose performance can be degraded in the presence of steam, for instance. ZIFs have high CO2 capacities and selectivity against CO and N2 is good. As there is a great deal of flexibility in the kinds of ZIF structures that can be synthesized, it is likely that new materials with even better adsorption selectivity and capacity can be developed in this way.

4.1.2 Functionalized Fibrous Matrices

The need for both high capacity and fast diffusional response in adsorbents can be addressed by using chemically modified fibrous materials to show adsorptive selectivity and capacity for CO2. Li *et al.* (2008a,b) attached polyethylenimine to glass fiber matrices through appropriate coupling chemistry to develop an adsorbent with high CO2 capacity that (1) worked more effectively in a humid environment and (2) could be completely regenerated at high temperature without loss of performance.

4.1.3 Poly (Ionic Liquids)

A new class of solid adsorbents based on the polymerization of ionic liquids (these are discussed below) has been reported by Tang *et al.* (2005a,b). These polymers exhibited enhanced sorption capacity and rates relative to those observed for the room temperature ionic liquids. Researchers have inferred from these results that the mechanism for CO2 capture with this new class of polymers is bulk absorption rather than surface adsorption. Bara *et al.* (2008) showed similar enhanced selectivity in polymerized ionic liquid gas separation membranes.

4.2 Structured Fluid Absorbents

4.2.1 CO2 Hydrates

Spencer (1999) and others have suggested that CO2 hydrates be exploited for carbon capture. This approach involves CO2 being incorporated in the cages, or clathrates, formed by water molecules under high pressure (7-20 atm) and low temperatures (0°C-4°C), as dictated by thermodynamic constraints on the formation of these hydrates. The concept was not to use the water hydrates as a recyclable absorption medium, although it is conceivable to do so, but rather to directly sequester the hydrate slurry. Based on more recent reports that tetrahydrofuran (THF) reduces the incipient equilibrium hydrate formation conditions, a process has been described that involves three hydrate stages coupled with a membrane-based gas separation process. This process could operate at a substantially lower pressure than is required in the absence of THF (Linga *et al.*, 2007, 2008). Compression costs were estimated to be reduced from 75 percent of the power produced for a typical 500 MW power plant, to 53 percent. This work is important because of its use of additives to enhance and expand the range of application of water clathrates, and because it points to possible new approaches for the design of suitable absorbents under more general conditions.

4.2.2 Liquid Crystals

While it is appealing to rely on the physical hosting of the solute in structured cavities like those provided by CO2 hydrates, the reliance on water as the clathrating agent restricts the accessible range of operating conditions for such processes. And although this range can be expanded with the use of additives such as THF, other structured materials, such as liquid crystals, provide potentially more flexible stimuli-responsive sorbents for gas sorption purposes. This is because their operational temperature ranges can be tuned to be compatible with a given process. Liquid crystals constitute an unusual state of matter: They can exhibit ordered, crystalline-like structures with liquid-like properties over certain temperature ranges, but above a well-defined transition temperature they convert to more traditional liquid phases. The restructuring of this phase can be achieved by a slight drop in temperature, or by the application of a suitable electric or magnetic field. As an example, Chen *et al.* (1993, 2000) and Hsuie *et al.* (1994) measured the physical absorption of CO2 in films of a liquid crystal exposed to pure CO2 over the temperature range spanning the solid to liquid phase transition. Their experimental results showed that the amount of CO2 absorbed by the liquid crystalline phase is significantly less than that absorbed in the isotropic liquid. The liquid crystals can be ordered dramatically by very small changes in temperature (1°C) or, in principle, by the application of a strong electric field across the liquid crystal film. Furthermore, the ability to reverse their physical sorption and desorption of CO2 with very small external perturbations showed a stimulus-responsive CO2 separation. The gas solubility in conventional liquid crystals, however, is unacceptably low for CO2 separation from flue gases, although it is comparable to the capacities exhibited by water clathrates. Note, however, that none of the work done to date on liquid crystals has focused on using these systems for separation purposes. Thus there is ample scope for enhancing CO2 capacities through appropriate design of the molecules. Means for enhancing CO2 sorption capacities in liquid crystal systems are required; developing such means through advanced materials R&D will require a strongly interdisciplinary approach that draws on synthetic chemistry, physical characterization, and molecular modeling.

4.2.3 Ionic Liquids

Another area of research that has demonstrated significant potential and is currently drawing a great deal of interest involves ionic liquids. Ionic liquids are organic salts with melting points usually near room temperature — that is, below 100°C. An unexpectedly large solubility of CO2 gas in ionic liquids was first reported by Blanchard *et al.* (1999) (see also Anthony *et al.*, 2002). Since then, there has been growing interest in exploring and understanding the solubility of various gases in ionic liquids (Wu *et al.*, 2004; Anderson *et al.*, 2007). Recently, it has been reported that CO2 absorption and desorption rates in poly (ionic liquids) are much faster than those in ionic liquids and that the absorption/desorption is completely reversible (Anderson *et al.*, 2007; Tang *et al.*, 2005*a,b*). The gas absorption capacity of ionic liquids, both in monomeric and polymeric materials, depends on the chemical and molecular structure of the ionic liquids, especially the anions (Tang *et al.*, 2005*a*). In general, ionic liquids are characterized by extremely low vapor pressures, wide liquid ranges, non-flammability, thermal stability, tunable polarity, good electrolytic properties, and easy recycling (Cadena *et al.*, 2004). These attributes make them attractive candidate sorbents for CO2 capture and separation from the post-combustion flue gas of coal-fired power plants. However, desorption of CO2 in ionic liquid media and regeneration of the sorbent require significant thermal energy (Trilla *et al.*, 2008). In addition, the viscosity of ionic liquids is relatively high — about five-fold higher than that of a traditional aqueous solution of MEA (Meidersma *et al.*, 2007) — and increases with CO2 loading. This leads to an additional energy penalty in pumping the sorbent.

4.3 Non-Thermal Regeneration Methods

4.3.1 Electrical Swing Adsorption

Adsorption processes with activated carbon, zeolites, and other mesoporous adsorbents are generally carried out in thermal swing operations where the adsorption occurs at a given temperature and the desorption and sorbent regeneration is achieved at a significantly higher temperature. Again, the thermal load adds to the efficiency losses associated with these capture processes. To overcome these thermal requirements, an isothermal electrical swing adsorption process has been proposed (Judkins and Burchell, 1999*a,b*; Burchell *et al.*, 2002). Specifically, this process uses electrically conductive adsorption media so that when a power supply is applied, a current passes through the matrix. This results in the desorption of the adsorbed component. It has been claimed that this desorption is not caused by resistive heating of the matrix, but rather results from a direct electrical effect on sorbate-sorbent interactions. However, no specific mechanisms have been advanced for such interactions.

A similar process has been proposed for an electro-desorption compressor (Pfister *et al.*, 2003), in which the sorbate is adsorbed at a low pressure, and desorbed at a significantly higher pressure; again, it is claimed that the desorption reaction is essentially non-thermal. While much progress has been made in identifying sorbents with appropriate electrical properties, it is still not clear what the mechanisms for the enhanced desorption processes are. Advanced research should focus on understanding these mechanisms and, once they are understood, on exploiting them to design more effective adsorbents, with possibly more controlled stimuli-responsive properties. Molecular modeling could play a large role in this endeavor.

4.3.2 Electrochemical Methods

The electrochemical separation and concentration of CO2 from a dilute gas mixture has been demonstrated using a benzoquinone as the carrier within a suitable solvent phase (either an organic solvent or an ionic liquid) (Scovazzo *et al.*, 2003). Specifically, CO2 is able to bind efficiently to the benzoquinone in its reduced or charged state, but is released readily when the carrier is oxidized. This appears to be a promising approach for the post-combustion capture of CO2 since it does not require significant heating and subsequent cooling to regenerate the sorbent and prepare for the next sorption cycle. In addition, there is ample opportunity for the development of new materials and processes based on such redox approaches. The redox-active carriers must be able to undergo reduction and oxidation in both the presence and absence of the sorbate, and must exhibit the desired selectivity and capacity for CO2 in the reduced state, with a significant reduction in capacity when the carrier is oxidized. The reaction kinetics should be sufficiently rapid that the reaction does not limit the overall sorption/desorption processes.

4.4 Summary and Conclusions

Advanced R&D on selective CO2 capture is required to develop new aids to separation that have high capacity and selectivity for CO2 under the operating conditions typical of flue gas emissions. One avenue of research will be the continued development of specialized adsorbents with finely controlled structures, such as uniform, well-defined cavities and pores, as are found with MOFs and ZIFs. These specialized adsorbents can provide high selectivities and capacities for CO2 in flue gases, while still being sufficiently robust to the presence of other components, such as water vapor. The functionalization of adsorbent surfaces (e.g., fibrous matrices, etc.) to provide desired separations capability and rates is also a target of opportunity for advanced R&D.

At the same time, liquid phase absorbents such as ionic liquids will continue to be an active area of research, with the continuing goal of optimizing their physical as well as chemical properties. Another research area that deserves attention is the development of non-thermal methods (e.g., electric swing adsorption, electrochemical methods) for regenerating liquid or solid sorbents. Such methods will require the development of new separation media that are more finely-tuned in their responses to externally-applied stimuli. These requirements pose stimulating challenges for efforts to (1) synthesize new materials — most likely aided by detailed molecular modeling of sorbate/sorbent interactions — and (2) develop new integrative module designs that enable these new materials to be effectively implemented in a process environment.

5 RD&D Recommendations

A few key points emerge from the above review of post-combustion capture technologies:

- In theory, there are many approaches to post-combustion capture.
- The state of development of these approaches varies widely.
- If one had to deploy the technology today, the only real option is a chemical absorption process (e.g., scrubbing with amines or ammonia).

In offering RD&D recommendations, it is important to articulate program goals. For CCS in general (and post-combustion capture in particular) program goals should include advancing both near-term solutions (which can help develop a commercial technology market in which CCS is part of the response to legislative mandates or carbon costs) and longer-term, improved solutions (which can enable deeper reductions at lower cost). In some discussions, the near-term and longer-term solutions are considered at opposite ends of the RD&D spectrum, and both have strong proponents today. However, the reality going forward is that a robust CCS RD&D program must respond to shorter-term needs while also anticipating longer-term needs. That means creating and maintaining an RD&D pipeline that begins with basic research and ends with commercial demonstrations for worthy technologies.

Since strong arguments can be made for emphasizing either short- or long-term scenarios, we recommend that the viewpoints expressed on both sides be considered in putting together a research portfolio. This includes activities aimed at "technology readiness" (i.e., ensuring that the technology can provide a significant amount of emissions reduction) as well as activities aimed at achieving significant cost reductions (through high-risk, high-reward projects). In other words, ***it is essential to develop a portfolio approach to post-combustion capture RD&D***.

To provide a solid basis for developing this portfolio R&D approach, we recommend that a national statistical database be assembled that describes those features of the existing U.S. coal fleet that are most relevant for assessing post-combustion capture technology. This database might draw on data currently provided to the U.S. Environmental Protection Agency (US EPA), the U.S. Department of Energy (US DOE), the Federal Energy Regulatory Commission (FERC), and other organizations. It should include, at a minimum, a statistical representation of the current coal fleet in terms of flue gas temperature, moisture, CO2, oxygen and sulfur dioxide concentrations, steam cycle and steam turbine parameters, as well as metrics for (1) the physical space available at the plant site for retrofit equipment and (2) local electrical system reserve margin or excess capacity. This information would feed into the portfolio approach, which we envision as a research pipeline.

For convenience, we divide the pipeline into four sections:

- ***Exploratory research*** will feed the pipeline. Many of the technologies described in the previous section fall in this category. Since many of these technologies can be characterized as high-risk, high-reward, a large number of projects should be underway in this part of the pipeline, but the funds expended per project should be low. Moving along the pipeline, we would expect the number of projects to decline, but the RD&D investment for each project to rise.
- ***Proof of concept research*** constitutes the next stage of the pipeline. Technologies that look promising, based on their performance in the exploratory research phase, will be expected to proceed to proof of concept. The goal at this stage is to understand whether the technology under consideration is appropriate for the task of post-combustion capture. Activities may include laboratory work to synthesize materials, measure basic properties, and analyze behavior in realistic environments (such as those found

at power plants). This is a key stage in the pipeline, in that it becomes much more expensive to move a project to the next stage of the pipeline (pilot plants). The more work is done at the proof of concept stage, the higher the odds that the next stage will be successful if the decision is made to move the technology forward.

- ***Pilot-scale testing*** is the next part of the pipeline. In terms of size, pilot projects are typically built on the scale of single megawatts or tens of megawatts — as a result, individual project costs can rise significantly. For example, Vattenfall's roughly 10 MW-equivalent pilot plant for oxy-combustion capture cost about $100 million.
- ***Demonstration projects*** constitute the final stage of the pipeline. The scale of a demonstration project is typically in the hundreds of MW and costs can easily exceed one billion dollars per project. At least a few demonstration projects are needed before a technology can claim "commercial readiness." These demonstration projects will need to absorb (and hopefully eliminate) first-mover costs and will set a baseline for the cost and performance of future commercial plants.

In parallel with the RD&D pipeline, there is a need for competent, objective, and independent analysis of the various technologies in the pipeline. Money for RD&D is always limited, and good analysis can help identify what areas look the most promising. This is especially important in the early stages of the pipeline, where it is necessary to select a limited number of technologies to promote to the relatively expensive pilot plant stage.

While robust, independent analysis of technology progress and potential sounds like an obvious component of a sound R&D program, it is usually hard to implement. First, the analytical challenge is often akin to comparing apples to oranges to grapefruits. Second, most of the data required to conduct the analysis will come from technology developers, who want to show their technology in the best light. Therefore, we recommend this analysis be done at a very fundamental level: It should serve a gatekeeper function (rather than aim to rank different technologies). A number of key components must be considered:

- Energy and mass balances. These are the bases for all processes. Yet, in reading the literature, we are amazed at the claims made about new processes in which no energy and mass balances are provided.
- How does the process match the design criteria? For post-combustion capture, processes need to work well at atmospheric pressures and relatively low CO2 concentrations (i.e., 5-15 percent by volume). An understanding is needed of how the process deals with the impurities in flue gas, including the presence of SOx, NOx, oxygen, and water, as well as trace amounts of metals, chlorides, and particulate matter. Estimates are needed of the expected recovery of, and selectivity for, CO2.
- In the power industry, processes with high availability are critical. Therefore, it is important to understand the robustness and the operability of a process.
- In this early stage, cost should not be considered a major criterion in deciding whether a process should advance to the next stage in the RD&D pipeline. Any cost estimates at this early stage of development are highly uncertain. However, some basis should be provided for assuming that it will eventually be feasible to make the process cost-effective.
- Preliminary lifecycle impacts analysis. A preliminary 'fatal-flaw' analysis should be performed to assess whether each process has potential for more than niche deployment given critical raw materials or manufacturing constraints, or potential environmental or social impacts.

We can now combine the above framework with the technology assessments supplied earlier to see what the post-combustion capture RD&D pipeline looks like today. We start at the demonstration end and work backwards.

- ***Demonstration projects.*** The Group of Eight (G8) wealthy industrialized nations has stated that its goal is to complete 20 CCS demonstration projects worldwide by 2020. These demonstration projects would include post-, pre-, and oxy-combustion, as well as capture from non-power sources. However, in terms of CCS from a power plant, we are still waiting for the very first demonstration project. A proposed demonstration project in the UK is one of the furthest along in planning; it calls for post-combustion capture. According to the project web site:[6] *"The Government selected post-combustion capture on coal for the demonstration project as it is most likely to have the biggest impact on global CO2 emissions and because it can be retrofitted once the technology has been successfully demonstrated at a commercial-scale."* The current timeline for this demonstration plant shows a start date of 2014. In the near-term, it seems almost certain that any demonstration project involving post-combustion capture will need to be based on chemical absorption technology. In the United States, the recently passed economic stimulus package contains money for CCS demonstration projects, while in Europe, revenues from the sale of 300 million permits under the European Emissions Trading Scheme have been reserved to fund CCS demonstrations.

- ***Pilot plants.*** At present, pilot activity is focused on testing alternative solvents. At GHGT-9[7], several groups presented papers reporting on pilot activities that involve various forms of amines, including CSIRO from Australia (Cottrell *et al.*, 2008), MHI in Japan (Kishimoto *et al.*, 2008), the University of Regina in Canada (Idem *et al.*, 2008), and the EU CASTOR project in Denmark (Knudsen *et al.*, 2008). Alstom and EPRI reported that a pilot, 35 metric-ton-per-day CO2 capture system using the chilled ammonia process was in operation at the We Energies Pleasant Prairie Power Plant in Wisconsin (Kozak *et al.*, 2008). In addition, Powerspan reported that a 20 metric-ton-per-day CO2 pilot plant based on their ammonia process (the ECO2 process) was nearing completion at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio (McLarnon and Duncan, 2008). Beyond these chemical absorption technologies, there do not seem to be obvious candidates for new pilot tests in the pipeline at this time.
- ***Proof of Concept.*** A large number of technologies are being examined at the proof-of-concept stage. As described earlier, they fall in the categories of adsorption, membrane-based separation, biomimetric approaches, as well as advanced approaches that involve new materials (e.g., liquid crystals, ionic liquids or metal organic frameworks) and designs (e.g., electric swing). While a broad range of technologies is being researched, however, increased effort (i.e., more funds, more relevant expertise) is needed in this area. This statement is based on the observation that while many technologies are being investigated, very few candidate technologies are ready to advance to the pilot stage at present.
- ***Exploratory Research.*** This is the research that feeds the pipeline. It is encouraging that a number of new concepts and technologies have recently been considered for post-combustion capture. However, this is just a start and more interest needs to be generated in the basic science community to develop new approaches to post-combustion capture. Not only is it important to generate fresh ideas, it is also important to attract leading researchers. A program that attracts world-class researchers will greatly improve the chance of success.

To reduce program costs, accelerate technology development, and ensure that post-combustion capture technology is available globally when and where it is needed, we suggest that some of these RD&D efforts (including demonstration projects) might be conducted in cooperation with developing countries such as China and India. In these countries, new coal plants are being built at an astonishing rate, and the costs for construction (and RD&D) are significantly lower than in the United States. In fact, low-carbon energy technology is in some respects advancing faster outside the United States. In China, for example, the GreenGen IGCC plant with carbon capture is already under construction and a large-scale CO2 geological sequestration effort is likely to commence in the near term at a Shenhua coal facility. A domestic RD&D program for post-combustion capture should therefore be considered part of a global cooperative endeavor.

Based on our review of the current status of post-combustion capture technology, we offer the following conclusions and recommendations:

- A portfolio approach to RD&D, developed in an international context, is required.
- Only chemical absorption technologies are well developed enough to be considered for demonstration.
- Reducing the parasitic energy load is a critical research goal.

[6] http://www.berr.gov.uk/whatwedo/energy/sources/sustainable/ccs/ccs-demo/page40961.html

[7] 9th International Conference on Greenhouse Gas Control Technologies, 16 - 20 November 2008; see http://mit.edu/ghgt9/.

TABLE 2 **Estimated Cost of an 8-10 Year U.S. Post-Combustion Capture Research Effort**

Component	# of Projects	Cost Per Project (Millions of $)	Total Cost (Millions of $)
Demonstration	5	750 (500-1000)	3750
Pilot Plants	15	50 (25-100)	750
Proof of Concept	30	10	300
Exploratory Research	50	1	50
Simulation/analysis			100
Contingency			1000
TOTAL			5950

- There is a big gap in the RD&D pipeline in moving technologies from the proof-of-concept stage to the pilot plant stage. Focused efforts are needed to close this gap. One strategy is to engage experts who have relevant expertise, but who are currently outside the CCS research community.
- Demonstration projects are important not only in terms of their immediate purpose (i.e., to advance a technology), but because they give visibility and credibility to the field and can be used to inspire new ideas and attract new researchers.
- Most technologies currently in the RD&D pipeline will fail. Therefore it is critical to keep feeding the pipeline with new ideas and new researchers to increase the overall chances of success.
- To facilitate informed decision-making along the way, there is a need to develop competent, objective, and independent analysis methodologies for evaluating the various technologies in the pipeline.

The final question is what the cost of a serious post-combustion capture RD&D program would be. We estimate the cost of an 8-10 year research program in Table 2 above. Note that the table shows total program costs, including research funds from both the private and public sector. Also note that these estimates cover only post-combustion capture technology — a complete CCS RD&D budget would also need to address other types of capture systems (i.e., pre-combustion, oxy-combustion), as well as CO2 transport and storage requirements.

The basis for these estimates is as follows:

- ***Demonstration project.*** The cost shown per demonstration project is an order of magnitude figure based on estimates from a recent (2007) MIT report called *The Future of Coal*, the experience of FutureGen, and other estimates. Of course, the specifics of a given demonstration project can vary widely, as would costs. We envision both retrofit and, potentially, new power plants in the 200-300 MW range that capture about 60 percent of the exhaust CO2 (to give the plant parity with emissions from a natural gas power plant; see Hildebrand and Herzog, 2008).
- ***Pilot plants.*** Pilot-scale activities underway today include plants sized to process flue gas associated with 1-5 MW of electricity production, as well as plants sized to process flue gas associated with tens of MW of electricity production. For many technologies, pilot plants have been built at both scales. Therefore, we anticipate the need for about 15 pilot plant tests. The cost range reflects the different size of pilot plants to be built. Many of these would be constructed as slip stream retrofits to existing installations.
- ***Proof of Concept.*** The cost of these projects will be variable: Some may cost only a few million dollars, while others could cost $20 million or more. Our estimate is based on a reasonable average cost.
- ***Exploratory Research.*** Because it is important to cast a wide net, we recommend funding many of these projects. After spending about $1 million, enough information should be available to decide whether a given technology or process shows sufficient promise to move to the proof of concept stage.
- ***Simulation/analysis.*** The MIT Future of Coal Study suggested that $50 million per year should be spent in this area for all types of CCS tech-

nology. We scaled this estimate down to reflect the level of funding needed for post-combustion capture technologies only.

- ***Contingency.*** Because of uncertainty in these estimates (and in terms of future prices), we have included a 20 percent contingency. ■

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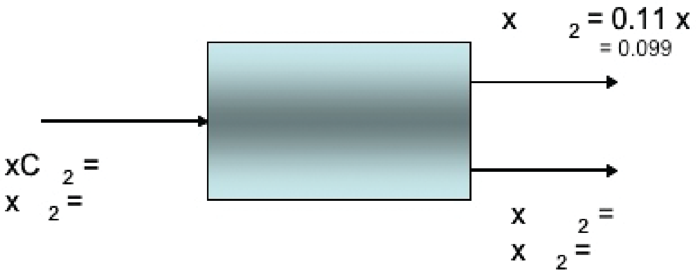
Appendix A
Minimum Work Calculation



Ideal work of separation:

Consider 1 mole of gas containing 11 percent CO_2 and 89 percent N_2. We will assume separation at 298 K and assume 90 percent capture of CO_2.

For a steady flow system, we have the minimum thermodynamic work as:

$W_{min} = W_{flue\ gas} - W_{CO_2} - W_{N_2}$

$$W_{min,N_2} = -RT\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\right)+\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\right)\right)$$

$$W_{min,FG} = -8.314x298x(0.11\ln 0.11 + 0.89\ln 0.89)$$

Wmin, FG = 0.859 kJ/gmol flue gas

Wmin, CO_2 = 0 since it is a pure stream

$$W_{min,FG} = -RT\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\right)+\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\right)\right)$$

$$W_{min,N_2} = -8.314x298\left(\frac{0.011}{0.011+0.89}\ln\left(\frac{0.011}{0.011+0.89}\right)+\frac{0.89}{0.011+0.89}\ln\left(\frac{0.89}{0.011+0.89}\right)\right)$$

Wmin, N_2 = 0.163 kJ/ 0.901 gmol FG
= 0.181 kJ/gmol FG

Wmin = 0.859 – 0.181
= 0.678kJ/gmol FG

Since 90 percent CO_2 is captured i.e. 0.9 x 0.11 = 0.099 gmol CO_2/gmol flue gas

W min, normalized = 6.85 kJ/ gmol CO_2 = 0.001904 kWh/ gmol CO_2 = 43 kWh/tonne CO_2 captured

The above result holds for 90 percent capture.

Ideal work of compression:

Work of compression = Availability at 110 bar – Availability at 1 bar

From NIST webbook

Temperature (K)	Pressure (bar)	H (kJ/mol)	S (J/mol-k)
298	1	22.257	120.54
298	110	11.166	50.979

Availability = H – TS

At 1 bar, availability = -13.664
At 110 bar, availability = -4.0257

Work of compression = 9.638 kJ/mol = 61 kWh/t CO_2 compressed

Power plant work:

From the MIT Coal Study:
SCPC plant
500 MW
415t CO_2/hr
500000kW/415 t/hr = 1200 kWh/t CO_2 produced

CHAPTER 4

Commercial Deployment of Geologic Carbon Sequestration:

Technical Components of an Accelerated U.S. Program

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LAWRENCE LIVERMORE NATIONAL LABORATORY

Carbon capture and sequestration (CCS) provides a promising pathway for achieving swift, dramatic, and sustained reductions in global greenhouse gas emissions. CCS involves capturing and separating CO2 from industrial and power plant flue streams, and then compressing and transporting it at high concentrations for storage underground. Geologic carbon sequestration (GCS) refers to the portion of the process in which the captured CO2 is injected into suitable deep geological formations, where it remains indefinitely. While CCS can be used in a number of contexts (i.e., natural gas and biomass power generation, petroleum refining, biofuels production, cement making, and chemical manufacturing), it is primarily considered as a means of reducing CO2 emissions from coal-fired power generation.

Over the past decade, CCS has been gaining ground as an important component within a comprehensive response to climate change. Several institutions, including the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA), the U.S. Department of Energy (DOE), the Massachusetts Institute of Technology (MIT), and the Electric Power Research Institute (EPRI), have recently carried out studies examining the technical viability and abatement potential of CCS.[1] Their findings have led to a number of key conclusions:

- First, without CCS, the cost of achieving atmospheric stabilization for a range of scenarios will increase 50-80 percent.
- Secondly, it is extremely unlikely that stabilization below 550 parts per million (ppm) can be achieved without CCS.
- Thirdly, CCS is technically sound and feasible based on analogous, long-lived industrial processes, as well as a handful of successful projects in different parts of the world.

With respect to geologic carbon sequestration (GCS) in particular, the current literature finds that:

- GCS resources are widespread globally — including in key OECD and developing countries — such that the capacity likely exists to sequester tens to thousands of gigatonnes[2] of CO2.
- Over time, the costs of GCS are likely to decrease and the safety and effectiveness of GCS are likely to increase.

For these and other reasons, CCS features prominently in the American Recovery and Reinvestment Act of 2009 (economic stimulus package adopted earlier this year in the United States), and the proposed American Clean Energy and Security Act (ACESA) recently adopted by the U.S. House of Representatives. It has been a theme in recent discussions between President Obama and the governments of Canada and China.

Yet, if CCS is to play a meaningful role in achieving atmospheric stabilization, the United States will likely need to increase dramatically the number of GCS projects in operation by 2030. Dooley *et al.* (2008) estimate that to stabilize greenhouse gas concentrations at 550 ppm, worldwide deployment must jump from 5 million tons per year (today) to 260 million tons per year within just eleven years. Stabilization at more stringent climate targets — 450 ppm or below — could require gigatonne-scale CCS deployment by 2020, according to the U.S. Climate Change Science Program (2007). In the United States alone, the Energy Information Administration's (EIA recent analysis of ACESA estimates that as much as 69 GW of coal with CCS would be deployed by implementation of the ACESA proposal - which could mean well over 100 large GCS projects (EIA, 2009).

In order to reach these targets, the United States must launch an accelerated research and development program aimed at readying GCS technology for broad commercialization. The issue is not whether saline formation sequestration is possible or safe or effective today – plenty is known based on other geological expertise, particularly in the oil industry and based on enhanced oil recovery (EOR) practices, to establish the core discipline – but rather whether the level of predictive capac-

Photo on page 59.

Denbury Resourses Green CO_2 Pipeline Under Construction in Louisiana in Early 2009.

The pipeline will connect new industrial and natural sources of CO_2 near the Gulf of Mexico to EOR fields in Texas.

Image courtesy of Denbury Resources, Inc.

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[1] A full list of recent published reports on CCS and GCS, including relevant web links, is available at the end of this document.

[2] One gigatonne equals 1 billion metric tons.

ity in the industry is adequate for efficient case-by-case decision-making. There appears to be near-consensus among leaders in sequestration efforts that an enhanced technical capability is needed for efficient regulatory and commercial transactions, and that the only way to develop that capability is through iterative study of commercial-scale injections of CO2. While industrial analogs such as EOR and acid gas disposal provide a solid base of experience upon which to develop first demonstration and early commercial GCS projects (especially in preferred and well circumscribed geological settings) a deeper predictive understanding of the geophysics, geochemistry, and geomechanics of sequestration is required to more effectively and efficiently assess project risks and inform stakeholder participation.

With the increases in programmatic budget, strong leadership within the DOE, and the addition of ARRA (stimulus) projects and funds, the current DOE Office of Fossil Energy program in GCS is very active. Much of this activity is based on years of research road mapping and stakeholder buy in (DOE-NETL, 2009), and much is aimed at answering key questions from a set of stakeholders and is well configured to succeed. This activity has also created opportunities to gather new knowledge, science, and information and to test new technology. It is vitally important that the United States seize these opportunities and that these programs have sufficient funds and clarity of mission to achieve the goals. A goal of this document is to help strengthen that mission and provide additional thoughts as to how those goals might be achieved.

This document identifies the critical research topics and technical concerns that should form the focus of a GCS program in the United States. The core areas addressed include:

- **Research and Development:**
  - Hazard assessment/risk management (groundwater protection, geomechanics, well bores)
  - Monitoring and verification (novel tools, integration, lab work)
  - Applied science and technology (advanced simulators, experimental test-bed, basic science)
- **Demonstration/Field Program:**
  - Enhanced U.S. program
  - Integrated projects
- **International Collaboration:**
  - Field program
  - Non-technical work
  - Geologic assessments

The discussion begins with an overview of GCS, including an overview summary of the history of geological carbon storage and the current state of research and deployment efforts.

I. Description of Geological Carbon Sequestration

Geological carbon sequestration involves the injection and long-term storage of large volumes of CO2 in deep geological formations (Figure 1, page 62). The most promising reservoirs are *porous and permeable rock bodies*, generally at depths of roughly 1 kilometer, where pressure and temperature conditions enable CO2 to enter a supercritical phase in which its viscosity and density are similar to that of oil. A number of geological reservoirs appear to have the potential to store many hundreds to thousands of gigatonnes of CO2. The most important units are saline formations. These contain brine in their pore volumes (salinities greater than 10,000 ppm) and are widely distributed geographically. The CO2 sequestration capacity of saline formations in North America has been estimated at between 1,300 and 3,000 gigatonnes (DOE NETL, 2008).

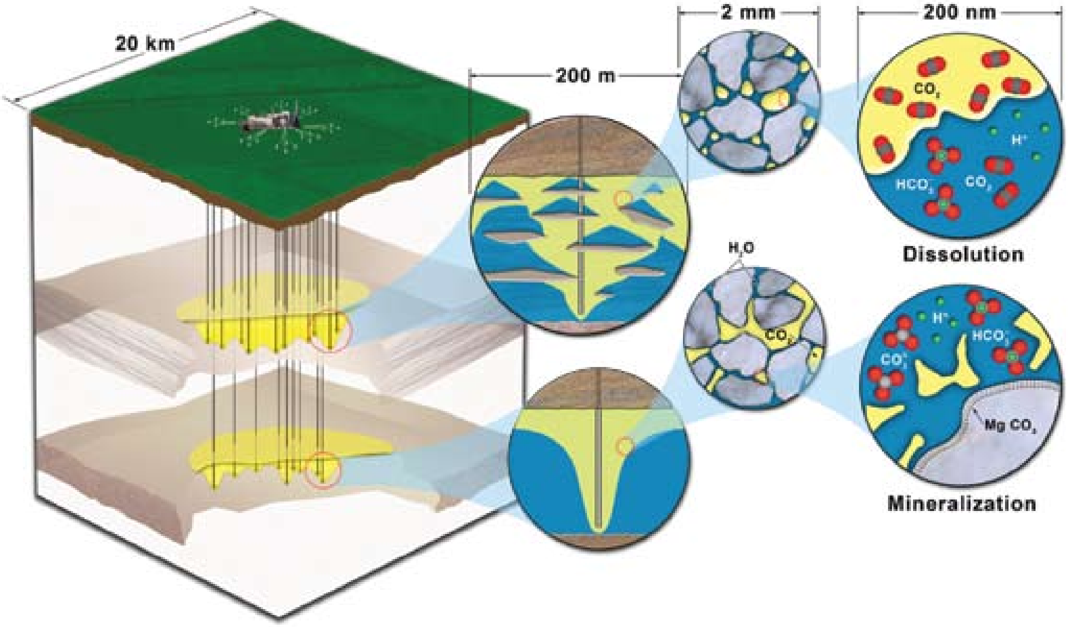
Mature oil and gas fields, which have some combination of water and hydrocarbons in their pore volumes, also serve as potential sequestration sites. In some cases, economic gains can be achieved through the use of captured CO2 for EOR or enhanced gas recovery. Substantial use of CO2 in EOR applications already occurs in the United States, with more than 60 million tons of CO2 injected annually from natural and anthropogenic sources. Based on 100-plus years of oil and gas exploration and exploitation, as well as experience with water management and hazardous waste disposal, both saline formations and mature oil and gas fields are well understood in terms of their porosity, permeability, physics, and basic chemistry.

Because of their large storage potential and broad distribution, saline formations are likely to provide the predominant locale for geological sequestration. However, initial projects will probably occur in mature oil and gas fields as part of

FIGURE 1

Schematic Diagram of Large-Scale Injection at 10 Years Time Illustrating the Main Storage Mechanisms.

All CO_2 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 CO_2 as a mobile phase (lower) and as a trapped residual phase (upper). Right insets show CO_2 dissolution (upper) and CO_2 mineralization (lower). From MIT, 2007



EOR operations, due to the density and quality of subsurface data that exist for these sites and the potential for economic returns. Other sequestration targets, such as deep coal seams, basalts, and organic shale, may also prove viable; but these are not yet at the same level of commercial readiness and thus are not considered here.

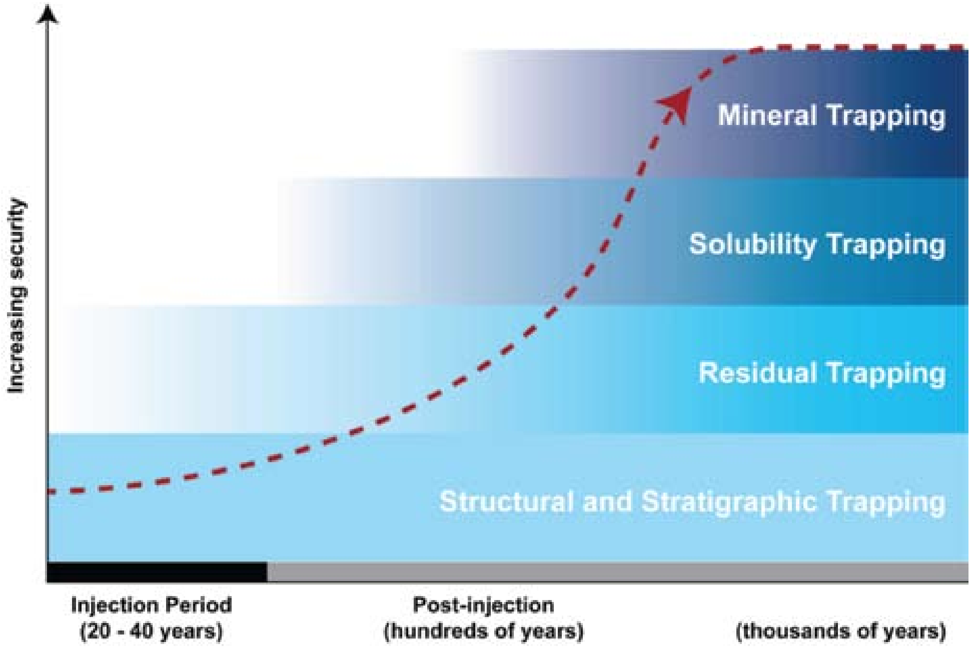
For saline formations and mature oil and gas fields, CO2 storage mechanisms are reasonably well defined and understood (Figure 1). Candidate sites must have physical barriers to prevent CO2 from migrating through the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the reservoir target. Barriers may also be dynamic, however, if they exist in the form of regional hydrodynamic flow. In these cases, the storage mechanism allows for very high CO2 pore volumes (in excess of 80 percent) and acts immediately to limit CO2 flow. At the pore scale, capillary forces will immobilize a substantial fraction of a CO2 bubble. That fraction is commonly measured to be between 5 and 25 percent of the pore volume, but in some cases it may be as high as 50 percent. This CO2 will be trapped in a residual phase within the pores and will act over longer time scales as a CO2 plume, attenuated by flow. Once in the pore, the CO2 will dissolve into other pore fluids, including hydrocarbon species (oil and gas) or brines, over a period of tens to hundreds of years. Unless other processes intervene, the CO2 will remain fixed in these fluids indefinitely; over longer time frames (hundreds to thousands of years), the dissolved CO2 may react with minerals in the rock volume and precipitate as new carbonate minerals. In short, the multiple mechanisms and multiple timescales for trapping CO2 indicate that sites will generally improve their performance over time (Figure 2).

While substantial work remains to characterize and quantify these trapping mechanisms, they are currently understood well enough to allow confident estimates of the percentage of CO2 that can be reliably stored over some period of time. This understanding stems from decades of studies in analogous hydrocarbon systems, natural gas storage operations, and CO2-EOR. For well chosen and operated sites, the fraction of stored CO2 will likely reach 99 percent over 100 years and will likely exceed 99 percent over 1000 years (IPCC, 2005). Moreover, some physical trapping mechanisms appear to be self-reinforcing — such as

FIGURE 2

Schematic Diagram Showing the Relative Timescale and Importance of Different Physical and Chemical Trapping Mechanisms During GCS.

From CO_2CRC, 2007



mineral carbonation of the cap-rock — and thus will improve the integrity and long-term performance of the storage reservoir. Further investigation will reduce the uncertainties associated with long-term storage efficacy and will allow for improved numerical estimates of storage volume capacity; yet today no significant knowledge gaps today appear to cast doubt on the fundamental feasibility of CCS.

II. Summary of GCS History, Including Recent Commercial Projects and Research Efforts

Geological storage of anthropogenic CO2 first emerged as a greenhouse gas mitigation option in the 1970s, but the idea only began to gain credibility in the early 1990s through the research efforts of individuals and groups in North America, Europe, and Japan. The subsurface disposal of acid gas (which is a by-product of petroleum production with a CO2 content of up to 98 percent) in the Alberta Basin of Canada and in the United States, as well as ongoing experience with CO2-EOR, also provided important useful experience. Theoretical and industrial work culminated in 1996 with the commencement of subsurface CO2 injection at Sleipner in the Norwegian North Sea (Table 1). Sleipner is the world's first large-scale GCS project; operated by StatoilHydro, it sequesters approximately 1 million metric tons of CO2 each year in a saline formation. Three additional commercial projects have followed Sleipner; they include Weyburn in Canada, In Salah in Algeria, and Snohvit in the Norwegian North Sea — each of these projects has involved a substantial R&D effort.

It is worth noting that much of the basic knowledge and operational experience for GCS in these and other projects comes from analogous industrial activities (IPCC, 2005). The most important of these is CO2-EOR, in which CO2 is injected into mature oil fields to improve recovery. This application has allowed for development and testing of basic well design, pipeline design specifications and regulatory practice, compression and dehydration, subsurface CO2 monitoring, and CO2 recovery and re-injection (Jarrell *et al*, 2002). Another important industrial analog is acid-gas injection, in which acid-gas mixtures — including hydrogen sulfide (H2S) and CO2 — are separated at natural gas processing plants and disposed of through injection, often into saline formations. Natural gas

TABLE 1 **Some GCS Projects of Note**

Country	Company/ Entity	Project Name	Date of Run	Tons/y *or tons total*
Norway	Statoil	Sleipner	Oct. 1996 to present	1M *(~12M)*
Canada	EnCana and PTRC	Weyburn	Late 2000 to present	~1.2M *(~10M)*
Algeria	BP, Statoil, Sonatrach	In Salah	April 2004 to present	1.2M *(~6M)*
Norway	Statoil	Snohvit	June 2008 to present	0.7M
US	DOE	Frio Brine Pilot	Oct. 2004 and Oct. 2006	*1600 and 700*
US	DOE	FutureGen	Status uncertain	1M
US	DOE	Regional Partnership Phase III projects	Status pending	>300,000 for each project
Norway	Shell and StatoilHydro	Draugen/Heidrun	Status uncertain: 2012 target	~1.6M
Norway	StatoilHydro and Shell	Mongstad	Status uncertain: 2016 target	~1.2M
Australia	Chevron	Gorgon	Pending: 2010	6-8M
Australia	CO2CRC	Otway Basin	Apr. 2008 - late 2009	*100,000*
Australia	Stanwell/ Shell	ZeroGen (phases A and B)	Pending: 2012 (A), 2017 (B)	500,000 (A), 1.5 M (B)
Japan	METI/RITE	Nagaoka	2003-2004	*10,400*
China	Huaneng	GreenGen	Pending: 2013	~1.5M
China	Shenhua	Shenhua DCL plant	Pending: 2012	~3M
Germany	GFZ	CO2SINK	June 2008 – 2010	*100,000*
US	DOE	CCPI (Several)	Status: Pending	>1M per project
US	Duke	Edwardsport	Pending: 2014	1-4M
US	Hydogen Energy	HECA-Baksersfield	Pending: 2014	1.5M
US	AEP	Mountaineer	Sept. 2009	.1M

storage offers a third analog; here, natural gas is temporarily housed in deep geological formations and then reproduced to meet seasonal demands for natural gas. The United States has more than 400 natural gas storage sites, and roughly 10,000 work-years of operational experience world-wide have improved the safety and effectiveness of these facilities. All of these industrial analogs have provided practices, economic understanding, and regulatory frameworks that are useful to GCS deployment in the United States and abroad.

In this decade, major GCS research and demonstration efforts have been carried out in over 20 countries on four continents. While much of this work entails basic scientific research, some includes substantial field experiments and commercial demonstrations. Governments have supported much of this work. In the United States, funding is chiefly provided through the DOE's Office of Fossil Energy. Most countries and all pilot and commercial projects have also received major industrial sponsorship, both in-kind and direct. Collaborations between industry and government entities have proved critical to project success and to the eventual commercial deployment of scientific innovations and new technology.

Many non-technical efforts have also proceeded in parallel with the R&D and demonstration efforts listed in Table 1. The U.S.-led Carbon Sequestration Leadership Forum, the UK-led IEA Greenhouse Gas R&D Programme, the Canadian-led Industrial Project Assessment Center, and the Australian Global Initiative for CCS have been working to create the necessary conditions for the ongoing progress and expansion of CCS. These conditions include technology transfer, record and data keeping functions, regulatory framework development, and support of commercialization and financing efforts.

In terms of research, the U.S. DOE's Office of Fossil Energy has sustained GCS programs for many years (DOE NETL, 2007). Most of this work has occurred within the core R&D program and the Regional Carbon Sequestration Program. The

DOE's National Laboratories — including Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), Los Alamos National Laboratory (LANL), Pacific Northwest National Laboratory (PNNL), and National Energy Technology Laboratory (NETL) — have played significant research roles. Their work has included the development of simulators, field monitoring approaches and equipment, site characterization approaches, and preliminary risk qualifications and assessment methodologies. Several research universities have collaborated with the national laboratories in these efforts — most notably MIT, Stanford, and the University of Texas. The University of Utah, Montana State, the Colorado School of Mines, and a number of others, have also participated on a smaller scale. So far, over $400 million[3] has been spent under this national program over the past decade.

Major overseas research programs have also worked with and exchanged technical information both with each other and with U.S. research entities. In particular, Canada, Norway, and Australia have had active large-scale research programs, based primarily in universities, "centers of excellence," and state-sponsored research institutions (e.g., geological surveys). Other countries, notably Germany, Japan, China, and France, have also had substantial, long-lived programs. The work conducted within these programs has ranged from basic science, such as, simulation and laboratory experiments, to field demonstrations (see above).

Many institutions have published major works on CCS in recent years, ranging from technical reviews to guidelines for operators intended to help in the drafting of regulatory protocols. Some of the key documents released over the past five years are listed at the end of this document. The list is still incomplete but should suffice to reflect the depth, breadth, and scale of effort within the CCS research community.

III. Moving GCS Forward

1. Target Areas for U.S. Research and Development

As a market for CO2 sequestration emerges and the GCS industry matures, it is likely that private companies will take on much of the technology development burden themselves. In the near term, however, a targeted technology development program will reduce the risk and cost of GCS commercialization. This program should address the most pressing concerns and provide key information to (1) those interested in siting and operating projects, (2) those tasked with regulating those projects, and (3) those interested in seeing GCS proceed with the highest possible environmental standards.

The research program outlined below describes the most pressing areas of focus for GCS research and development going forward. Progress in these areas will help enable rapid commercialization in the United States. The program we outline discusses both key technical needs in the current context of GCS deployment efforts and emergent areas of concern outside the scope of older research programs. The key topics include hazard assessment and management, monitoring and verification technology, and applied science and technology development. As will be discussed in the next section (Demonstration Projects), these program elements must be investigated in the context of large-scale injection projects.

Importantly, much of the R&D needed to advance GCS can be done in parallel with early deployment efforts, which can provide a test-bed for key investigations or may even be required to address important deployment challenges. Similarly, much of the work will focus on sequestration in saline formations. In part, this is to help establish a new GCS industry that deals chiefly with saline formations rather than oil and gas fields. The relative weight of research and the timing of research efforts is such that components of this program may be able to move right away (e.g., research needs in the areas of monitoring and verification or combining EOR with sequestration are relatively modest and could be addressed fairly quickly). Other areas of research may require larger commitments of time and money to address the full spectrum of important challenges (e.g., hazard management or project integration). Nonetheless, both the R&D and deployment components of the recommended technical agenda can be launched quickly in many places in the United States and overseas.

■ *Hazard Assessment and Risk Management*

The most up-to-date research on GCS, combined with experience from industrial analogs,

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[3] Does not include funding from The American Recovery and Reinvestment Act of 2009

suggests that the knowledge and technological capability currently exist to carry out GCS projects safely and effectively (Friedmann, 2007). However, because of a lack of sustained experience with GCS operations, as well as a lack of comprehensive science programs at existing demonstration projects, there is not yet a sufficiently deep understanding of GCS-related risks under a variety of geologic conditions to enable wide-scale commercial use. In order to achieve widespread deployment of GCS, potential operators must understand their liability exposure, insurers must be able to manage commercial risk, and public stakeholders and regulators must be able to guarantee environmental protections. A comprehensive research effort is thus urgently needed to investigate and assess potential hazards associated with GCS. Recently, the DOE and NETL have announced a new multi-lab cooperative called the National Risk Assessment Program aimed explicitly at research and development on this and related topic. They will cover five risk areas, including methodological approaches, simulation and modeling, and these three critical topics:

- ***Groundwater protection (EPA, 2008).*** Underground drinking water is vulnerable to unintended leakage of CO2 out of the injection zone. The U.S. Environmental Protection Agency (EPA) is currently drafting rules for regulating underground CO2 with specific regard to groundwater protection. Potential concerns include the mobilization and transport of metals and/or volatile organic carbon compounds (VOCs), the intrusion of brine into drinking water, and dramatic changes in local or regional hydrology.

  An accelerated research program is needed to define best practices for site characterization, site operation, and project stewardship based explicitly on groundwater concerns. This initiative should include several components:

  - Laboratory studies of real and synthetic aquifers to understand the rate and concentrations, duration, and extent of mobilized metals and VOCs from rock-brine-CO2 interactions
  - An effort aimed at rapid, low-cost, non-invasive monitoring of shallow groundwater resources
  - Simulation of CO2 migration into local and regional aquifers in order better to understand and constrain potential consequences of leakage
  - Investigation into current, alternate, and novel mitigation tools and approaches for unexpected severe groundwater contamination and degradation

- ***Geo-mechanical risks.*** GCS differs most dramatically from industrial analogs, such as oil and gas exploration, in terms of the impact of CO2 injection on geo-mechanical conditions. In CO2-EOR, for example, CO2 is injected but oil is produced, and thus reservoir pressure is held more or less constant. By contrast, the injection of CO2 into a saline formation creates a pressure gradient that will grow over the lifetime of the project — perhaps 60 years. To date, little work has focused on the geo-mechanical consequences of large-scale injections, and even less work has been undertaken on the range of potential approaches to the management of sustained large-volume injection. Since this problem lies squarely outside of conventional oil and gas recovery practice, a substantial R&D program is warranted. This program should aim to achieve the following objectives:

  - Development of practices for fault mapping during siting and early project operation at the injection site
  - Development of current and novel approaches to defining the threshold for potential mechanical failure in the shallow crust (upper 5 kilometers)
  - Field- and simulation-based studies into fault reactivation, including induced seismicity and associated ground shaking
  - Laboratory and simulation studies looking at coupled geo-mechanical and hydrological effects, such as fault-fluid migration
  - Field, laboratory, and simulation studies of mechanically induced well-bore failure

- ***Wellbore integrity.*** Wells represent the likeliest failure points for a CO2 storage site. When rock has been penetrated by a well, the natural trapping mechanisms of the crust will not function. In addition, the history of subsurface industrial activities has repeatedly demonstrated that wells have the potential to fail even where the crust remains intact. Wells are vulnerable because they exist exclusively to bring fluids from deep in the earth up to the surface quickly.

Fortunately, this is also an area where existing industrial analogs will prove useful. Many industries have successfully deployed wells in large CO2 injection projects, and a great deal of experience exists recompleting and closing damaged or failed CO2 wells (Aines *et al.*, 2008; Lewicki *et al.*, 2007). Nevertheless, the specific operational needs of GCS will require additional knowledge and technology that the oil and gas industry have had no incentive to develop.

Thus, another focus of an accelerated GCS research program should be the development of technical approaches to the management and reduction of well-bore hazards. This initiative should include several components:

- Laboratory analysis of well-bore materials such as cements, casing, plugs, and rocks, as well as the interfaces between these materials
- Development of high-fidelity well-bore simulation tools for the purpose of CO2 injection
- Development of current and novel approaches to characterizing the well-bore environment
- Enhancement of existing tools to locate lost and abandoned wells at the surface
- Development of new practice and technologies to improve the performance of existing and new well bores

An accelerated research program focusing on these issues will give industry and regulators the technical information needed to make decisions about project permitting and operations. It will also help inform potential project stakeholders and the general public about the potential risks and consequences associated with large-scale CO2 injection.

Monitoring and Verification (M&V)

Successful deployment of GCS will require a combination of technology, regulation, and public acceptance. Thus, a critical role exists for monitoring and verification (M&V). In the context of GCS, M&V refers specifically to (1) monitoring the injection of CO2 into the subsurface reservoir and its subsequent movements, and (2) verifying the location and containment of the injected CO2 over time. This information enables project developers to ensure that there are no threats to human health and environmental systems — a basic condition for obtaining permits for sequestration projects. By providing an accurate accounting of stored CO2, M&V also provides a critical means of recognizing sequestration activities in the context of emissions reduction policies (such as a cap-and-trade system for greenhouse gas emissions) and for supporting such activities through financial mechanisms (such as a price on CO2 emissions).

Some of the M&V challenges for GCS include the use of various techniques that are sensitive to some subset of fluid and rock properties in order to monitor and quantify details of fluid movement and interactions. This difficulty is compounded by (1) the fact that the initial characterization of rock and fluid properties will necessarily have less detail than is desired, and (2) by the dynamic conditions under which the reservoir properties themselves change during the process of injection and plume migration.

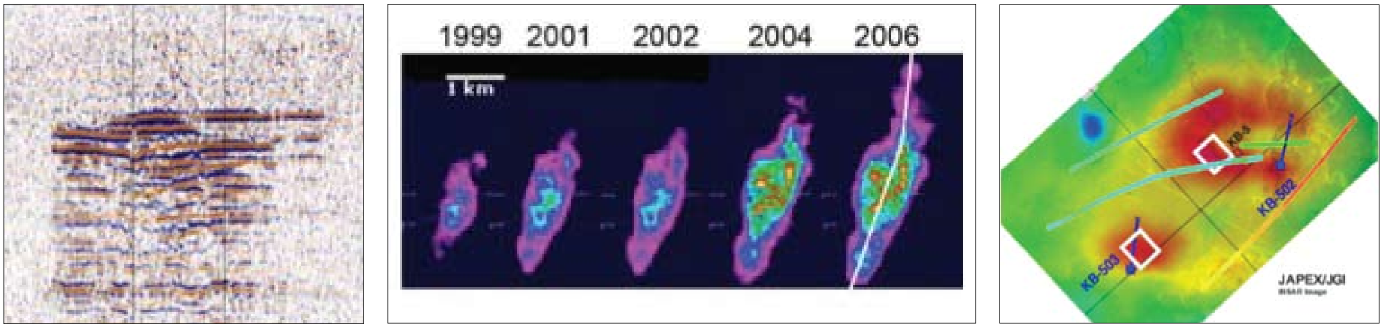
M&V activities should logically take place throughout the duration of a GCS project. During assessment and planning, related activities include site characterization, simulation and forward modeling, and array design and planning. Baseline monitoring establishes the reference conditions against which to compare changes during the injection process. Operational monitoring is necessary during injection in order to verify performance against expectations. Closeout and post-injection monitoring may include both surface and subsurface components; there may also be a need for additional efforts focused along high-risk zones.

M&V measurements must be repeatable and stable; the techniques used must prove both

FIGURE 3 **Potential Tools for Monitoring GCS Projects**

Potential tools for monitoring GCS projects. (A) Time-lapse seismic data from Sleipner. The left image shows the change in impedance between injection in 1996 and 2008. The right image shows successive maps of the top of the CO_2 plume over time. From CO_2 Capture Project, 2009. (B) An InSAR map showing the change in surface elevation (in millimeters) above the In Salah injection. Red areas have been uplifted approximately 2 cm, and blue areas depressed about 1 cm.

Courtesy of BP and the In Salah project.



their reliability over long periods of time and their applicability over multiple scales. Industry acceptance and a history of past applications are critical. Rock-physics models need to be refined and validated for interpretation; the ability to measure and separate fluid and rock properties is particularly important for achieving accurate quantitative results.

Numerous tools and techniques can serve to monitor variables of interest in the GCS process. For instance, *CO2 distribution* can be measured through the use of time-lapse seismic, microseismic, tilt, VSP, and electrical methods, while *CO2 saturation* can be determined through electrical and advanced seismic methods. In addition, pH sensors can detect *subsurface pH changes*, direct sampling can help determine *fluid compositional changes*, thermocouples, pressure sensors, fiberoptic systems, or Bragg grating can serve to measure *temperature and pressure changes*, gas sampling, use of tracers or hyperspectral methods can provide *surface detection*, while tri-axial tensiometers, Bragg grating, tilt, or Interference Synthetic Aperture Radar [InSAR] can pick up *stress-strain changes*.

Most of these techniques involve conventional M&V tools that were initially developed for different applications — primarily oil and gas exploration and production, natural hazard monitoring (e.g., volcanoes, earthquakes), environmental remediation, and general scientific studies of the earth. Thus, a focused research effort is needed to develop these tools for GCS and to refine and optimize their use in related applications. For example, site-specific laboratory analyses can be used to calibrate responses for survey methods that are expected to be used over the duration of a project. Moreover, improved technologies for quantifying CO2 saturation over time will prove important for managing operations, assuring environmental performance, and carbon accounting. The following areas deserve particular attention under an M&V research program.

- ***Novel tools.*** Some novel tools and methodologies hold great promise to provide robust yet cost-effective monitoring capability for GCS. Examples include microseismic monitoring to track plume migration and reservoir response, InSAR for remotely measured, field-scale indications of plume migration, and electrical resistance tomography (ERT) for more detailed monitoring of plume movement. These tools and approaches provide information beyond the location of stored CO2 — such as the state of stress in the crust, the degree of surface deformation, or CO2 saturation and phase state — that is relevant for both accounting and hazard management.
- ***Integration of results.*** Integrating the results of multiple monitoring techniques to provide a comprehensive understanding of project evolution will be critical to proper reservoir management and successful CO2 storage. Various methods are under development for the joint inversion and interpre-

tation of such results. The optimal method will be one that can invert highly disparate data sets — incorporating both "hard" data, such as individual measurements, and "softer" data that have greater uncertainty — and include some estimate of the robustness of each. One approach, known as Monte-Carlo Markov Chain analysis (e.g., Ramirez *et al.*, 2008), uses stochastic methods to compare known measurements and information with new measurements in order to quantify the likelihood of a given outcome. This approach identifies and ranks alternative explanations that are consistent with *all* available data based on their probability. Other approaches (e.g., sequential Markov Chain, conventional multivariate inversions, etc.) also have merit and could apply in appropriate circumstances.

An accelerated research program will lead to improved calibration of conventional methods and increase familiarity and commercial experience with these tools for use in GCS. Through integration, such a program will also improve quantification and resolution of CO2 distribution and state in the subsurface.

- ***Laboratory calibration of site data.*** Site-specific data on the distribution of key rock and fluid properties are critical, particularly under different fluid saturation and composition conditions. These include:
  - › Porosity, permeability, lithology, and structure
  - › Liquid, gas, water content and ratio, oil, etc.
  - › State of stress
  - › Fluid redistribution and change of state
  - › Fracture creation/opening/closure

  The specific geophysical, geochemical, or geo-mechanical response to CO2 injection is correlated to petro-physical and rock chemical attributes that are site controlled and site dependent in key ways. A robust M&V program should have a laboratory component to interpret and de-convolve the complex signatures of surface and subsurface monitoring. Importantly, these studies add critical quantitative constraints to the determination of rock and fluid properties. As such, they offer a basis for scaling local results to national practices and for developing international standards in M&V.

■ *Applied Science and Technology Development*

GCS presents many operational challenges. Presently, the technology for monitoring and simulating GCS processes at depth remains limited and incomplete. Despite the knowledge base built from analog industries, there is no widely available practice for managing GCS operations. A great many potential designs for GCS injection and project configuration have been proposed, but these stem largely from analog industries and thus may not always be appropriate. A new saline storage industry will likely face technical challenges specific to its operations that can't be immediately addressed by drawing upon experience from the oil and gas industries. For instance, GCS will require well design geared toward low-permeability rocks, which oil and gas producers generally avoid.

GCS deployment — on the scale of gigatonnes CO2 injected per year worldwide or 100 megatons injected per year in the United States — will demand a high level of due diligence, process control, and environmental credentials. To move GCS toward this level of readiness quickly, a technology development program must focus on providing insight into the problems described above and on answering the key questions of developers, operators, regulators, and public stakeholders. A handful of critical technologies can play a major role in accelerating R&D progress and addressing stakeholder concerns:

- ***Advanced simulation.*** In general, the simulation of multi-phase fluid flow in porous media is fairly advanced. However, GCS presents a set of physical and chemical processes that present-day simulators are poor at representing. These include mechanical responses to large subsurface pressure transients and the dissolution and precipitation of a large number of mineral species. Because these physical and chemical processes affect the local and regional permeability field, flow path, and retention, new computational tools are needed to help operators and regulators predict the performance of proposed and active projects.

While many simulators are available to address some or part of these concerns, they exist across a range of industries and institutions. Many of them are fit to a different purpose — such as , oil production or groundwater clean-up — and have not been applied to GCS problems. Thus, a focused effort is needed to couple existing models, develop new simulation tools, and validate these tools and models using prior field-test records and new field program opportunities. The program should aim to develop simulators that:

- Are fully three dimensional
- Couple hydrological, reactive chemical, and geo-mechanical processes
- Can simulate multiple well-injection configurations
- Have adequate CO2 equations of state
- Can represent heterogeneities and complexities in the subsurface
- Can accurately predict the fate and transport of CO2 over long time scales
- Can provide insight into environmental concerns during and after operation

A small number of U.S. research institutions have demonstrated capability in this area. In particular, some of the national laboratories (such as, Lawrence Livermore National Laboratory, Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory) and a few universities (Stanford, Princeton, and the University of Texas) have made substantial progress in GCS simulation. In addition, a few companies have expertise appropriate to the task (Schlumberger, CMG) and have begun collaborating with non-industrial research groups to pursue rapid development and commercialization.

A U.S. effort to improve GCS simulation would benefit from joint programs involving laboratory experiments, code development, and field validation. Such an initiative would pair initial modification and coupling of existing modules with a focused laboratory experimental program to help test and parameterize simulators. Subsequent efforts would test and validate models with publicly available data sets from prior tests.

An important goal of this work would be to develop a common set of accepted computational platforms that all potential operators and regulators would agree are suitably accurate and robust for the purposes of injection design, monitoring validation, and plume migration prediction. Similar common frameworks and standards exist to obtain air permits and injection permits for class I wells. Ideally, a working group would be established to share initial results and compare approaches. Finally, sets of simulators would be supported for prediction and verification, with field projects proceeding in the private sector in the United States or abroad.

- ***Experimental test-bed.*** In the oil and gas industries, companies develop technology at field sites, where experiments can be conducted at scale. Major advances in logging, improved and enhanced oil recovery, reservoir characterization, and novel production strategies (e.g., horizontal drilling) have been achieved in this setting. The GCS community currently lacks this type of test bed, and without a climate or carbon policy (and the commercial drivers that would be created by such a policy) a full industrial program for GCS may be many years away. Given this context, a facility devoted to GCS field experiments would prove enormously useful in accelerating the process of technology development and testing, as well as in answering basic science questions.

A new program could be launched in either a “green-field” site (i.e. a field where no prior subsurface work has taken place) or a “brown-field” site (i.e. a site previously used for oil exploration, EOR or CO2 injection). What is important is that the site have the following attributes:

- Regular and repeated access to the subsurface
- Well-understood geology and geophysics
- Multiple types of reservoir geology in one locale at multiple depths

  - Multiple wells for monitoring and operations
  - Access to large volumes of CO2 for conducting experiments at reasonable cost
  - Ability to ramp up quickly
  - A dedicated staff for maintenance of safety and operational needs
  - Proper shielding from indemnification

  Some field experiment programs have met many of these criteria — for instance, the DOE's Frio Brine Pilot, Germany's CO2SINK project site, and Australia's Otway Basin. However, most of these cases have been individual projects rather than sustained field efforts aimed at technology development. Over the last five years, proposals for this type of dedicated research program have emerged but have not yet achieved priority status. Such an initiative deserves urgent attention in order to move GCS toward widespread commercial deployment. At a minimum, one experimental field facility is needed in the United States, and two could potentially be developed over the next five years.

- ***Basic science.*** While many aspects of GCS are well understood, a substantial number of basic science questions remain. These range from questions about rates of mineral dissolution and precipitation, to questions about the way pressure waves from multiple injections interact across faults. Although most of these issues are not critical to the safe deployment and commercial success of GCS, they represent a realm of investigation that could yield improvements in operations, hazard management, and site performance. Some of the relevant areas of inquiry that remain unaddressed include:
  - Questions of fundamental processes, such as cement carbonation and imbibition rates
  - Characterization and quantification of uncertainty
  - Typical accuracy required for successful characterization
  - Concerns related to monitoring, such as acoustic and electrical properties of CO2-brine-rock systems, among others
  - Improved understanding of unconventional CCS resources, such as basalts, salt domes, organic shales, and offshore geological storage

  A new program aimed at investigating a set of basic science questions would begin to remedy this lack of understanding and help open the door to new cost saving and efficiency measures in the future. Many research institutions could potentially take part in this effort, including several national laboratories and universities. Because the questions are complex and the time scales for investigation are likely to be long, sustained funding is required. Similarly, the lack of near-term urgency means that a substantial proposal and review processes would be justified to ensure the highest level of scientific inquiry. The DOE's Office of Science has laid out a fairly clear and ambitious basic science agenda in support of GCS in their 2007 document (see above).

2. Demonstration Projects in a Range of Geological Settings

Large field demonstration projects are the single most important component of any U.S. or global research program. For GCS to be effective as a means of reducing CO2 emissions from large fossil-energy point sources, many large projects must be deployed worldwide. Such projects are critical because many of the fundamental processes and key geological thresholds can only be detected and understood at scale (Friedmann, 2006). In particular, geo-mechanical effects, the long-term behavior of CO2, and the far-field effects of displacement cannot be studied at pilot scales. Demonstration projects can begin to be deployed today in parallel with other R&D efforts. In fact, the R&D program described above would benefit greatly from open access to large-scale projects, where field knowledge and iteration can improve the speed of learning and reduce the cycle time for development. This is currently the model of scientific and technical effort being applied at the Weyburn project in Canada and the In Salah, project in Algeria, and it is being considerd for FutureGen, the Clean Coal Power Intiative (CCPI), and other new DOE projects.

Ultimately, field programs serve to demonstrate economics, performance, and environmental management; they also lead to technical discoveries and can help validate existing knowledge, simulation tools, and approaches. There are three ways a domestic GCS R&D program could engage in field efforts: (1) targeted U.S. GCS demonstration projects, (2) integrated GCS/CCS projects at scale, and (3) international GCS collaboratives. The first two approaches are discussed in this section; the third is included within the subsequent discussion on international collaboration.

■ *Targeted U.S. Field Program for GCS*

DOE has recognized the need for large field projects to address key technical questions relevant for GCS deployment. At present, DOE has accelerated the deployment of large projects in its Phase III partnership efforts. These programs, if properly executed, have the potential to address key technical questions and provide beneficial insights for GCS operation and regulation.

Meanwhile, regional partnerships are proceeding on an individual basis; yet, so far, the results have been uneven. This is due in part to a lack of adequate funding for scientific and technical missions. In some cases, insufficient clarity and the lack of a mandate regarding technical expectations for scientific efforts in Phase III projects also hinders the ability to deliver on national programmatic needs.

At a minimum, a U.S. GCS field program requires:

- Three large-scale projects (sequestering approximately 1 million tons per year), started within three years in a range of geological settings and with CO2 injection sustained for five years, and followed by two years post-injection study and integration
- Six large-scale projects within six years in a range of geological settings

A preferred program schedule and scale would entail:

- Two large-scale projects within two years in different geological settings
- Seven large-scale projects within four years in a range of geological settings; at least two of these on a scale greater than 5 million tons per year

Program goals include:

- A set of protocols every ***two years*** that integrates lessons learned from the projects with respect to site characterization, GCS project design, monitoring and verification, basic operations, and closure
- Formal recommendations to state, regional, and federal regulatory bodies concerning lessons learned, preferred practices, and hazard assessment and management
- Empirical and site-specific geological, geochemical, geophysical, and hydrological data and information for continued study and analysis

To accelerate safe and effective GCS deployment, efforts should focus on sites that can be characterized and started swiftly and safely. In addition, the technical component of these field demonstration programs should ensure adequate delivery of empirical information that will inform for operational and regulatory procedures going forward.

■ *Integrated GCS/CCS Projects*

Many researchers and technical experts currently working in the field of GCS (i.e. within the DOE's Fossil Energy division, the U.S Climate Change Technology Program, MIT, and elsewhere) have remarked on the need for large integrated capture and storage projects at commercial-scale power plants. Such projects are critical to provide engineering and economic bases for decision making, to demonstrate and develop integrated capture and storage facilities, and to provide early knowledge and empirical information to develop industrial practices and standards. Several programs in the DOE Office of Fossil Energy (FutureGen, CCPI) have this focus. In addition, there have been recent legislative attempts (such as the bill introduced by Congressman Rick Boucher to promote demonstration projects, that was later incorporated into the proposed ACESA) to expand and accelerate projects with these objectives in mind.

Integrated capture and storage projects provide a source of experience with the cost and performance issues that arise in coordinating the injection process with industrial CO2 offtake needs. Some of these integrated projects should be carried out in conjunction with the field demonstrations discussed above, but emphasis on integration and demonstration should be augmented by the research and development needs of each individual part of the process. Projects of this type require new funds as well as strong management and direction to ensure that the key deliverables (e.g., operational practices for sequestration well design, injection, and monitoring) are brought into the public realm.

This is of crucial importance to harvest the opportunities provided by the natural field laboratories created by these large and complicated projects. Since such projects entail integrating the engineering and economics of complex surface and subsurface facilities, their sponsoring entities need to communicate clear expectations to the commercial operators and technical investigators. Ultimately, these efforts will enhance the prospects for commercial deployment of GCS by improving industrial practice and providing clarity to key stakeholders regarding the performance and operating needs of injection programs.

- ***International Collaboration***

Many countries (as well as the European Union) have begun large-scale GCS projects. These include integrated capture and sequestration projects, such as, ZeroGen, and projects that inject pure streams of byproduct CO_2 (e.g., Snohvit, Shenhua). In many cases, the projects provide a platform for rapid technical development and scientific investigation at relatively low cost. They also open potential pathways for U.S. technology-based commerce development. Furthermore, GCS projects may foster technology transfer and collaboration that can help facilitate dialogue in other climate-related areas (for instance, with China, India, and Brazil) or potentially address other energy security concerns (e.g., Poland, Turkey). In these contexts, the United States should greatly expand its current international programs and consider new avenues for collaboration and technical discovery.

- ***International Cooperation on Field Programs.*** Field programs offer the most immediate venues for collaboration. They require basic geological data and information; they also require locations where tools can be deployed and approaches tested at minimal cost. DOE should seek to engage and support U.S. scientists, investigators, and companies in field campaigns world wide. Bilateral agreements or umbrella partnerships, such as the Carbon Sequestration Leadership Forum, could help to facilitate this effort. Specific recommendations for international field programs include at a minimum:

› Major U.S. involvement in three large-scale international projects (approximately 1 million tons CO_2 injected per year) within the first year

› Major U.S. involvement with eight large-scale projects worldwide within five years

› Selection to cover a range of geological settings and host-country economic conditions

It would be preferable to have:

› Major U.S. involvement in five large-scale international projects (each injecting approximately 1 million tons per year) within the first year

› Major U.S. involvement with eight large-scale projects worldwide within five years, including five in key developing countries (e,g,, India, China, Brazil, Indonesia)

› Selection to cover a range of geologies (Note: Selection could be made through a combination of open solicitation and executive decision and should be driven by opportunity, technical parameters, and public benefit.)

- ***International Cooperation on Non-technical Issues.*** The commercial deployment of GCS in the United States will also depend on a number of non-technical issues. These include permitting requirements, regulatory structure, subsurface ownership and access, and long-term liability. Other nations have already begun work in these areas, and in some instances, they have begun to codify decisions and technical constraints. While some of foreign examples will not translate readily to the U.S. context (e.g., Crown ownership), others will prove applicable.

At present several mechanisms exist through which the United States can engage

GCS issues internationally. They include the policy working group of the DOE's Carbon Sequestration Leadership Forum (CSLF) (http://www.cslforum.org/), the IEA's working groups and forums, various international conferences and workshops, and the Asia Pacific Partnership co-sponsored by the U.S. State Department and the DOE. The potential exists to expand all of these efforts through existing channels and by investing additional resources. Two examples are useful to consider here.

- ***Australia's Global CCS Institute.*** Recently, Prime Minister Rudd of Australia announced the creation of the Global CCS Institute (GCCSI), a multi-national body of experts with a mission to facilitate the commercial deployment of CCS in many countries. The government of Australia has committed over $100 million per year for five years and the Institute is beginning to hire staff and clarify its charter (See: http://www.zeroemissionplatform.eu/website/docs/GA3/ZEP%202008%20GA%20-%20Hartwell%20Australian%20insights.pdf).

  The government of the United States became a founding member of the GCCSI on July 14th and is considering its range of commitments in terms of time, staff, and money. Yet, this initiative presents a clear opportunity to increase knowledge and to create and improve deployment protocols world-wide, thereby both accelerating the commercialization of CCS and increasing the U.S. share of global markets for this technology.

- ***World Resources Institute CCS Guidelines for China.*** Under the Asia Pacific Partnership, the World Resources Institute (WRI) has launched a set of U.S.-China exchanges and study tours with the goal of accelerating the development of CCS guidelines in China. WRI has directly partnered with Tsinghua University and many key Chinese organizations, increasing the chance that guidelines will evolve organically to serve that country's specific policy, economic, and environmental needs. The WRI effort could be expanded through the DOE and U.S. State Department to include more training and technology transfer as well as high-level summit meetings between critical U.S. and Chinese stakeholders.

- ***Support for International Geological Assessment.*** The current state of knowledge about GCS resources greatly limits the speed of deployment and market penetration in the United States and world-wide. So far, only two countries (the United States and Australia) and one Canadian province (Alberta) have carried out necessary geological mapping in any level of detail. It appears that key countries and regions — in particular, India, China, and Eastern Europe) lack the know-how and sponsorship to execute similar studies. Some countries, notably Australia, have begun to sponsor geological assessment work in other countries in the hopes of improving trade relationships and accelerating CCS deployment.

  Under one potential model for engagement, the United States would partner bi-laterally with other key nations and provide staff, sponsorship, and knowledge in support of regional and national geological assessments. The United States could also spearhead an effort to get the G8 or OECD nations to contribute to a general fund dedicated to this assessment task.

IV. Draft Budget Requirements

Ultimately, program costs will reflect program goals. They will also depend on program design, the number of participants, and the way in which tasks are completed and executed. A detailed roadmap will shed more light on likely program expenditures, as will decisions regarding specific program goals, the degree of emphasis on international vs. domestic projects, and the extent of focus on basic scientific work. We present some preliminary budget estimates below, in order to help bound the discussion in terms of reasonable technical requirements. It is important to note that these numbers reflect only the GCS component; costs for carbon capture experiments, plant design and demonstration, and large-scale capital construction are not included in these estimates and will need to be considered and assessed independently.

YEAR 1	$305M
YEAR 2	$805M
YEAR 3	$905M
YEAR 4	$1205M

The following is a breakdown of funding for the first year and subsequent out years based on the program described above.

YEAR 1 (total recommendation = $305M)

Hazard assessment/ risk management	$ 20M
Ground water	*$ 5M*
Geomechanics	*$ 5M*
Wellbores	*$ 5M*
Other	*$ 5M*
Monitoring and verification	$ 15M
Novel tools	*$ 6M*
Integration	*$ 4M*
Lab work	*$ 3M*
Other	*$ 2M*
Applied Science and Technology	$ 20M
Advanced simulators	*$ 4M*
Experimental test-bed	*$ 10M*
Basic science	*$ 9M*
Other	*$ 2M*
Field program	$ 200M
Enhanced US program	*$ 200M*
International	$ 35M
Intl. field program	*$ 20M*
Intl. non-technical	*$ 4M*
Geol. Assessments	*$ 8M*
Other	*$ 3M*
Other support	$ 10M

YEAR 4 (total recommendation = $1205M)

Hazard assessment/ risk management	$ 20M
Ground water	*$ 5M*
Geomechanics	*$ 5M*
Wellbores	*$ 5M*
Other	*$ 5M*
Monitoring and verification	$ 25M
Novel tools	*$ 10M*
Integration	*$ 8M*
Lab work	*$ 4M*
Other	*$ 3M*
Applied Science and Technology	$ 30M
Advanced simulators	*$ 3M*
Experimental test-bed	*$ 20M*
Basic science	*$ 10M*
Other	*$ 2M*
Field program	$ 1100M
Enhanced US program	*$ 1100M*
International	$ 25M
Intl. field program	*$ 17M*
Intl. non-technical	*$ 3M*
Geol. Assessments	*$ 3M*
Other	*$ 2M*
Other support	$ 10M

Recent Reports and Web Resources Related to CCS

Intergovernmental Panel on Climate Change, IPCC Special Report on Carbon Dioxide Capture and Storage, 2005, Interlachen, http://www.ipcc.ch/

International Risk Governance Council. 2008. Policy Brief: Regulation of Carbon Capture and Storage. http://www.irgc.org/

IOGCC second recommendations IOGCC 2007 — Interstate Oil and Gas Compact Commission, Geological CO_2 Sequestration Task Force. 2007. Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for the States and Provinces. http://www.crossroads.odl.state.ok.us/cdm4/item_viewer.php?CISOROOT=/stgovpub&CISOPTR=3726&CISOBOX=1&REC=9

MIT, The Future of Coal, MIT press, 2007, 192 p, http://www.mit.edu/coal

National Petroleum Council, 2007, Facing the Hard Truths About Energy, Washington, DC, 442p

US DOE, 2007, Basic Research Needs for Geosciences: Facilitating 21st Century Energy Systems. Dept. of Energy Office of Basic Energy Sciences, Washington, 287 p., http://www.sc.doe.gov/bes/reports/list.html

U.S. Environmental Protection Agency, 2008, Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration(GS) Wells: Proposed Rule. http://www.epa.gov/safewater/uic/pdfs/prefr_uic_CO2rule.pdf

World Resources Institute, Guidelines for Carbon Capture and Sequestration, major contributing author, 2008, World Resources Institute, Washington DC, 103p

In addition, both the International Energy Agency (IEA) and the DOE's National Energy Technology Laboratory (NETL) regularly publish materials on CCS. The IEA documents can be obtained on the IEA website (http://www.ieagreen.org.uk/). In addition, IEA hosts a database of world-wide CCS projects and the meetings and summary reports of technical working groups (http://www.co2captureandstorage.info/). The IEA is also a co-sponsor of the Greenhouse Gas Control Technology Conference series (GHGT) (http://www.ieagreen.org.uk/ghgt.html) and has helped to publish the proceedings of the last five conferences.

NETL has also published numerous roadmaps, atlases, guidelines, and technical reports on CCS. Much of this literature is available through the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/refshelf.html) and through the Office of Fossil Energy. Key documents include the annual technology roadmap (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/project%20portfolio/2007/2007Roadmap.pdf) and two atlases of CO_2 sequestration for North America (early 2007 (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/index.html) and late 2008 (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/atlasII.pdf). NETL has also hosted an annual conference on CCS (www.carbonsq.com) and publishes the proceedings through ExchangeMonitor (http://www.exchangemonitor.com/). Finally, NETL co-sponsored GHGT-9 with the IEA in 2008.

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CO_2 Capture Project 2009, A Technical Basis for Carbon Dioxide Storage (C. Cooper, Ed.), http://www.co2captureproject.org/co2_storage_technical_book.html

Dooley JJ, RT Dahowski, and CL Davidson. 2009 "Comparing Existing Pipeline Networks with the Potential Scale of Future U.S. CO2 Pipeline Networks." Energy Procedia, Volume 1, Issue 1, February 2009, Pages 1595-1602. GHGT9 Procedia doi:10.1016/j.egypro.2009.01.209

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Ramirez, A, Friedmann, S.J., Foxall, W.A., Kirkendall, B., Dyer, K., 2006, Subsurface imaging of CO2 plumes using multiple data types and Bayesian inference, 8th Greenhouse Gas Technology Conference, Trondjheim, Norway, Poster session II

Also, Links to:

National Petroleum Council document: http://www.npchardtruthsreport.org/

WRI document: http://www.wri.org/publication/ccs-guidelines

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