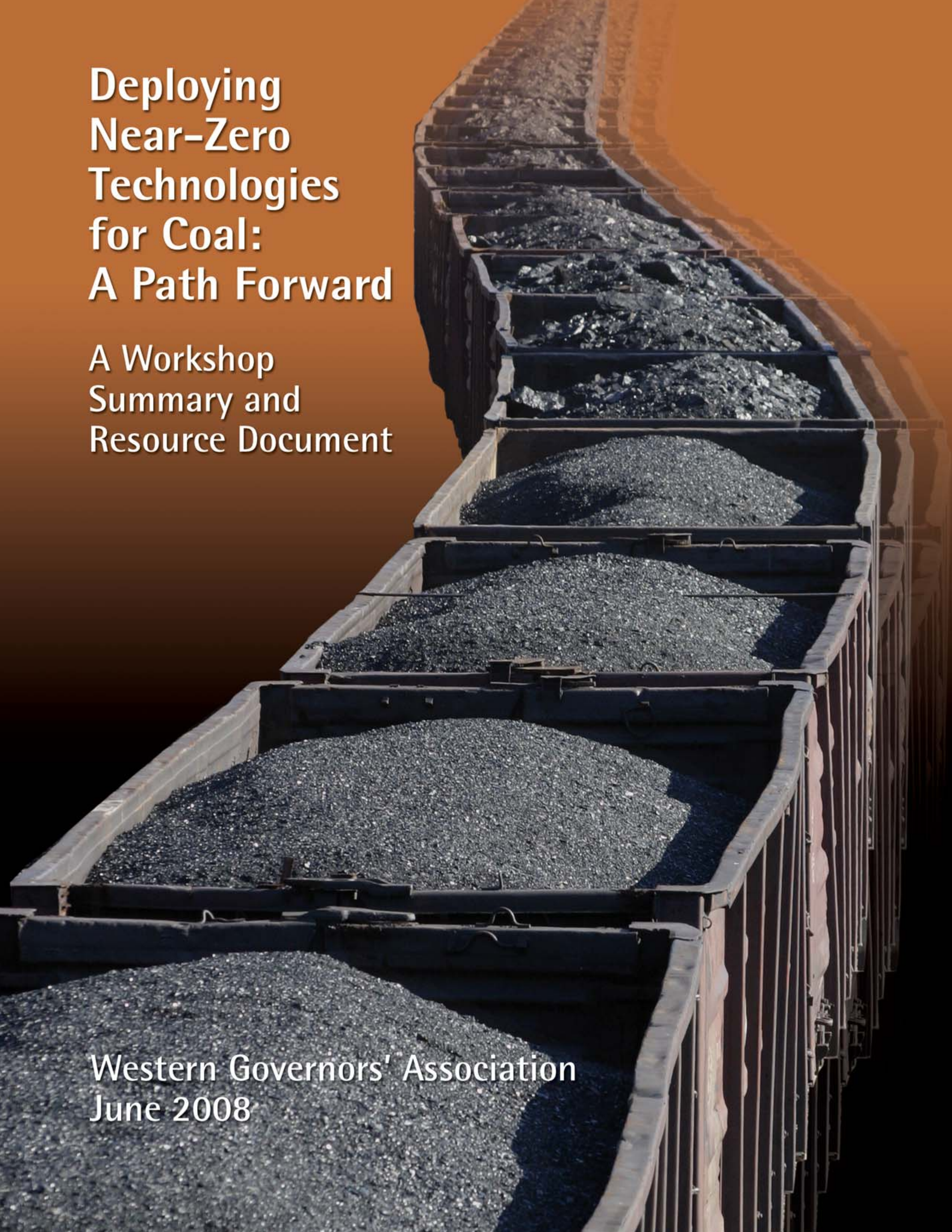
Deploying Near-Zero Technologies for Coal: A Path Forward

A Workshop Summary and Resource Document



Western Governors' Association
June 2008

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Executive Summary

This summary of the Western Governors Association workshop "*Deploying Near-Zero Technologies for Coal: A Path Forward,*" held in Denver, Colorado on October 23rd, 2007, identifies concepts that western state governments could consider to facilitate the technical and regulatory pathways for deployment of near-zero-emission coal-fired power plants. The workshop was part of a continuing effort by the WGA to implement the recommendations of the Clean and Diversified Energy Advisory Committee convened by the Western Governors' Association[1] to increase new clean energy generation in the West by 30,000 megawatts by 2015. In the 2006 Clean and Diversified Energy report, the governors agreed to:

- Support continuing efforts to improve the efficiency and environmental performance of all advanced coal technologies examined by the Advanced Coal Task Force; and
- Support incentives for the development of advanced coal technologies that are not yet commercially viable and operate with superior environmental performance.

Specifically, the Governors stated goal is achieving near-zero emissions from coal-fired power plants at a competitive cost of electricity. The Governors further pushed for funding of multiple pilot programs, both to determine the costs and operating characteristics of advanced coal plants and to evaluate environmental and public health and safety impacts for geologic sequestration of CO2.

This summary also draws from the expert presentations and roundtable discussions that occurred at the workshop. Presentations included experts from industry, the environmental community, government, the financial services sector, and the sciences. Participants in the workshop were asked to identify the necessary steps to achieve deployment of near-zero emission coal technologies in a carbon constrained, clean and diversified energy portfolio. This summary also includes supplemental information on advanced coal technologies and carbon capture techniques.

The Fundamental Issue

The West is the fastest growing region in the United States. In fact, nine of the 10 fastest growing counties are in WGA states.[2] Added to that population growth is the effect of a society increasingly dependent on personal electronic devices, where per capita consumption of electricity increased 13% between 1990 and 2003.[3] That growth spurs either a need to develop new electrical generating capacity or to substantially reduce per capita consumption.

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[1] Western Governors' Association. "Clean Energy, a Strong Economy, and a Healthy Environment: report of Clean and Diversified Energy Initiative". June 2006. See: http://www.westgov.org/wga/meetings/am2006/CDEAC06.pdf and Western Governors Association. "Clean and Diversified Energy Initiative. Advanced Coal Task Force Report", January 2006. See: http://www.westgov.org/wga/initiatives/cdeac/Advanced%20Coal-full.pdf. The CDEAC report presented recommendations on achieving 30,000 MW of clean energy by 2015 and a 20% increase in energy efficiency by 2020.

[2] CNNMoney.com

[3] World Resource Institute estimates of U.S. average per capita electrical consumption

A range of readily deployable technologies exists to achieve reductions in carbon dioxide emissions from coal-fired power plants. Some technologies, such as ultra-supercritical boilers, offer near-term (3-5 year) results and potential emissions reductions of up to 30 percent at best. Other technologies, such as carbon capture and storage (CCS), will enable near-zero emissions, but face economic obstacles to wide-scale deployment over the next 5-10 years without targeted subsidies and incentives. There are also technologies, such as IGCC plants, which function at higher efficiencies comparable to new ultra-supercritical pulverized coal and, although they can be designed to be "capture ready," would not actually capture emissions without the addition of specific carbon capture equipment. These plants do reduce emissions per unit of energy produced compared with conventional coal plants and provide project and operational experience in one component of an integrated carbon capture and sequestration system.

Given the need to deal with increasing population, accommodating electricity demand, and meeting the Governors' goal to have clean generation, discussion centered around what role coal can play, and in what timeframe. This summary acknowledges that CCS remains an additional economic burden on the cost of electricity and that infrastructure issues such as pipelines, coordination of new and existing plants with reserves, and an accepted policy framework remain uncertain. Still, the challenge for industry is to take the steps necessary to reduce these burdens.

It has become increasingly difficult to get new coal generating facilities permitted, regardless of the technology to be employed. To a great degree this is driven by a concern for adding new carbon dioxide emissions to the atmosphere. To achieve near-zero emissions coal generation, it is necessary to capture and sequester the carbon emissions. Unfortunately, at the current rate of research and regulatory development, it will be some number of years before regulated sequestration will be a reality.

This leads to the policy question of whether it would be acceptable to "ramp-up" to high levels of carbon capture and sequestration or whether there should be a moratorium on construction of new coal facilities if they do not deploy high levels of capture and storage. On this point there was a clear division, with many of the environmental community proposing that no coal plant be built without immediate capture and sequestration and many utility and coal industry representatives arguing that while it is possible to reach high levels in time, it is more reasonable to build to this level in a series of steps. Industry argues that without the ability to make stepwise progression to high levels of sequestration, the construction of new coal burning facilities is severely limited.

Workshop participants from the environmental community expressed concerns about proposed new coal power plants that did not meet an array of environmental criteria. Specifically, there was opposition to construction of any new coal power plant that:

- Does not have an enforceable commitment to capture and geologically sequester its carbon dioxide emissions in a permanent and verifiable manner;

- Does not achieve the greatest possible reductions of conventional and hazardous air pollutants;

- Does not responsibly manage its solid wastes and its impacts on water resources;

- Does not respect local communities and ecosystems - for example, irresponsible application of mountain top removal coal mining, failing to fully reclaim mine sites as required by law, or adversely affecting disproportionately burdened communities.

It appears that the future of coal as a source of electricity from new facilities is highly dependent on the availability of regulated sequestration and on the cost of the technology. Still, workshop participants recognized, consistent with the CDEAC Advanced Coal Task Force Report, that public investment and incentives for new coal capacity should be limited to only those facilities that can clearly demonstrate a clear, meaningful and verifiable commitment to near-zero emission coal technology.

The question that must be answered is -- How will the region meet electricity demand in the long term while maintaining a commitment to clean energy? The answer seems dependent to a certain degree on how soon we can make new and existing coal plants near-zero emissions.

Common Assumptions and Conclusions

As could be expected, the workshop did not produce a clear consensus among the varied group of stakeholders. However, the workshop did reveal a number of common assumptions and conclusions:

1) There is a need to reduce carbon dioxide emissions from energy use.

2) Regardless of whether new coal-fired generating plants are constructed in the coming years, existing coal power plants will continue to be a significant energy source for electricity generation in the United States for the foreseeable future. As a result, the ability of the United States to achieve the necessary steep and long-term reductions in carbon dioxide emissions depends on the development and deployment of technologies that enable coal to be used in a manner that avoids significant greenhouse gas emissions as we develop non-fossil fuel energy resources.

3) Financial incentives should provide clear and predictable market signals on the costs of abating carbon emissions. In particular, market based mechanisms that assign value to abatement of carbon dioxide emissions can provide long-term incentives for existing and new coal power plants to deploy near-zero emission technologies.

4) The cost of carbon capture and sequestration technologies will likely decrease with experience and demonstration projects employing different capture techniques and in different geological settings will accelerate technological improvement, scientific understanding and cost reduction. The economic viability of near-zero coal technologies will increase with deployment.

5) Deployment of carbon capture and sequestration technologies will entail a significant increase in public and private investment.

6) A small number of early commercial sequestration projects, together with over 30 years of experience with injection of large volumes of carbon dioxide into oilfields and other related industrial practices such as natural gas storage and acid gas disposal, have provided evidence that long-term carbon sequestration in properly selected geologic formations may be safe and effective.

7) A continuing, aggressive program of testing, monitoring and verification should be undertaken as part of new near-zero emission coal-fired facilities. This will support the development of rules, science, and monitoring programs needed to make sequestration a dependable long-term option.

Introduction: Coal Technologies, Carbon Capture and Sequestration

Two goals define the current energy challenge for the western United States: the reduction of carbon dioxide emissions from fossil fuel combustion and the sustainable development of energy resources sufficient to provide affordable and secure energy for the region. In its 2006 CDEAC report, the Western Governors' Association recommended that to meet these two goals, western states will require a diversified energy portfolio which includes fossil fuel, renewable, and energy efficiency resources. Western Governors have adopted this diversified energy strategy in their individual states and in regional initiatives. [4]

Although the workshop was an outgrowth of the CDEAC recommendations, it did not seek to assess the precise role that coal should play in each state's diverse energy portfolio. Those outcomes are best determined by competitive markets that incorporate all externalities. Instead, this summary addresses the technological and regulatory pathways which can enable coal to contribute to a zero-carbon energy future. It examines the opportunities and challenges that exist for coal to become a provider of near-zero emission energy, focusing on *how* to develop near-zero emission coal technologies instead of *whether* states should deploy them.

> ***"Deploying CCS at scale is not as much a question of technology availability but of economic viability. CCS is available today to play a significant role in reducing greenhouse gas emissions and addressing climate change."***
>
> Robert Malone, Chairman and President, BP America

This focus on *how* to facilitate near-zero emission coal technologies is based on three major findings of the Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Capture and Storage published in 2005. First, the IPCC Special Report confirmed the need for major reductions in carbon dioxide emissions. Second, the report demonstrated that CCS is a technology with enormous potential impact. The report states that CCS has the potential to deliver carbon dioxide emissions reductions of 15-55% of the cumulative mitigation effort needed by 2100. Third, the IPCC report supported the conclusion that CCS can be safe and secure. According to the IPCC:

> *With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environmental risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR and deep underground disposal of acid gas.*[5]

Echoing the IPCC findings, most U.S. academic experts, including those at Princeton, MIT, Harvard, and Stanford, agree that CCS is important for addressing climate change and could play an important role in addressing the energy security of the United States by enabling it to continue to use domestic resources that would otherwise emit carbon dioxide. Finally, a number of major energy companies such as BP, NRG, Shell, Schlumberger, AEP and Rio Tinto have concluded that CCS can make a large, practical and cost effective contribution to abatement of carbon dioxide

[4] Western Governors' Association. 2006. Clean and Diversified Energy Report. Denver, CO. 2006.
[5] Intergovernmental Panel on Climate Change. 2005. Special Report on Carbon Capture and Storage. See: http://www.ipcc.ch/ipccreports/srccs.htm

emissions. For example, according to Robert Malone, Chairman and President, BP America, "deploying CCS at scale is not as much a question of technology availability but of economic viability. CCS is available today to play a significant role in reducing greenhouse gas emissions and addressing climate change."[6] Similarly, the CEO of NRG, the 10th largest American power generation company, stated that "we need to move as quickly as possible toward implementing the low-emissions ways of combusting coal that are under development or, in the case of 'coal gasification' technology, are ready for commercial deployment."[7] Still, while there is strong belief in the technological viability of CCS, there is a need to expeditiously develop a regulatory structure that will allow its widespread use.

There exists an increasingly robust economic literature which can help guide expectations for the future rates of deployment of carbon abatement technologies. Over the last two years, several significant research efforts have analyzed the costs of technologies that abate carbon dioxide emissions. The most significant and influential studies have been the "Special Report on the Economics of Climate Change" prepared by Sir Nicholas Stern for the United Kingdom Ministry of Treasury, known as the "Stern Review", and the McKinsey study titled "Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?".[8] Although there are some differences among these studies in the detailed estimates of technology costs and the rates at which technologies can be deployed, there is strong agreement on a general cost curve for carbon abatement in which energy efficiency can be deployed at negative cost, many renewable sources can deploy at relatively low cost, while carbon capture and storage technologies deploy at relatively high costs near the top of the cost curve. These economic analyses suggest that under an efficient regulatory regime a range of energy technologies, starting with energy efficiency, will deploy prior to carbon and storage. According to the McKinsey analysis, which focuses on the United States, "almost 40 percent of abatement could be achieved at negative marginal costs."

The economic and technological analyses conducted to date further show that carbon capture and storage technologies, although more expensive than other abatement options, are critical to meet emissions reductions goals. According to the McKinsey study, carbon capture and storage is the largest single potential source of abatement for the United States and represents over 10 percent of the total potential U.S. abatement. In addition, carbon capture and storage technologies will be needed in order to meet commitments to achieve steep cuts in emissions currently under consideration in climate legislation.

The potential for carbon capture and sequestration is so great, in large part, because coal is a central component of the U.S. energy portfolio. In 2006, over 49 percent of total electricity generation derived from coal. Nearly 60 percent of U.S. coal production occurs in western states, making it both a major fuel for electricity and a major source of economic activity.

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[6] Written Testimony of Robert Malone, Chairman and President, BP America; Submitted to the Select Committee on Energy Independence and Global Warming, U.S. House of Representatives, September 21, 2007

[7] "We're Carboholics. Make Us Stop". By David Crane, Washington Post, Sunday, October 14, 2007

[8] For Special Report on the Economics of Climate Change see: http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/stern_review_report.cfm Stern Report. For "Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?" see: http://www.mckinsey.com/clientservice/ccsi/greenhousegas.asp McKinsey Institute.

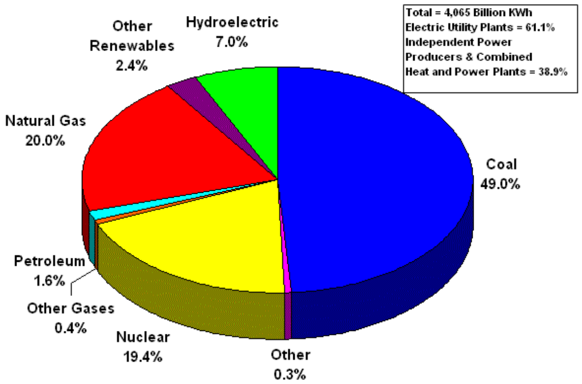
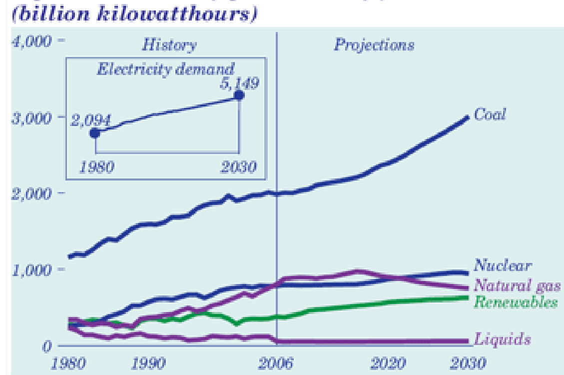


Figure 4. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



Coal has two characteristics that ensure its significance for the U.S. electricity supply for the foreseeable future. First, coal is abundant. Most estimates agree that recoverable coal reserves in the United States total over 250 billion tons, enough to supply 250 years of current consumption.[9] Roughly two-thirds of these reserves are located in the western states of Wyoming, Montana, Texas, Colorado, Utah and North Dakota. The abundance of coal means it has lower market costs relative to other fossil fuels.

Coal-fired power plants dominate the national electric infrastructure and have long life spans. Coal-fired power plants constitute 43% of installed U.S. generation capacity. Of the roughly 600 coal-fired power plants in the U.S., 265 are located in the western states, with all 19 western states having at least one coal-fired power plant. While the lifespan of a coal plant is usually 50 to 60 years, western coal plants are, on average, younger than the national average, so that many western plants have 25 to 35 years of future expected operation.

Despite the significance of coal reserves and generating capacity, the precise future of coal is uncertain. Coal-fired power plants are the largest industrial source of carbon dioxide in the United States. In 2004, these plants emitted 1.9 billion tons of carbon dioxide, accounting for more than 30 percent of total U.S. carbon dioxide emissions from all sources. Although all fossil fuel-powered plants produce carbon dioxide and emit that carbon dioxide to the atmosphere, coal generation is roughly twice as carbon intensive as natural gas. As a result, existing and proposed coal-fired power plants are a significantly more concentrated source of carbon dioxide emissions. In addition, the recent "Carbon Principles" issued by JP Morgan, Citigroup and Morgan Stanley demonstrate the new concern of financial institutions over how to value the risk of carbon exposure in the development of electricity generation capacity. [10]

Near-zero emission coal technologies depend on carbon capture and storage (CCS), a technology which is currently available, but not practiced on a scale sufficient to significantly contribute to climate change mitigation. Internationally, a small number of commercial

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[9] In a recent report, the National Academy of Science has indicated that recoverable reserves may be lower. The "life-span" of coal reserves will be reduced if either the size of reserves declines or the rate of consumption increases. See National Research Council, *Coal R&D for National Energy Policy*, National Academy of Sciences Press, Washington DC, 2007.

[10] See: "The Carbon Principles" at http://www.carbonprinciples.com/documents/Carbon%20Principles%20Final.pdf

implementation projects (at roughly 1 million tons per year) are successfully demonstrating various types of capture and sequestration technologies, with more in the construction and development phase. In the United States, the Regional Carbon Sequestration Partnerships are undertaking a number of research and demonstration projects, while commercial entities are proposing commercial projects. Key considerations for evaluating types of sequestration and their efficacy include ecological and groundwater resource impact, cost, timescale, and amount of carbon sequestered. Further research and development is necessary, as well as integrated large-scale capture and sequestration projects, to further clarify these issues.

Carbon capture is the first step in any type of direct carbon sequestration. According to most analyses, roughly two-thirds of the costs of carbon capture and sequestration will come from the carbon capture process. There are a variety of methods being developed for carbon capture but most follow the same general principles: a combination of solvent reactions and shifting pressures and temperatures is used to extract CO_2 from the gasified fuel or the exhaust of a coal power plant (except for oxy combustion which avoids solvent use). In general, carbon capture will be most efficient and least costly if a plant is designed with capture in mind from its inception rather than trying to retrofit carbon capture technology to existing plants. Because of the pressures and temperatures needed for carbon capture, a plant that is designed for integrated carbon capture will be fundamentally different than one built without it.

Carbon capture can apply to either of the two main types of plants in use today:

- *Pulverized coal power plants*:
  The traditional and most common type of coal power plant is a pulverized coal (PC) plant. The efficiencies of these systems depend on design, operating parameters and coal type and their efficiency ranges from 33 to 40 percent, with further advances expected to create plants with efficiencies as high as 46 percent. Implementing carbon capture on a sub-critical coal plant is expected to drop the efficiency by approximately 9 percent. For a super-critical coal plant, implementing carbon capture using today's technologies and at current costs is expected to increase the cost of electricity on a range from 50 to 60 percent. Improved integration schemes could cut this cost premium in half by the time of widespread deployment. Technologies for capturing carbon from pulverized coal plant exhaust are in the testing phases and commercial demonstration is in its early stages.[11]

- *IGCC power plants*:
  A newer type of coal power plant is the Integrated Coal Gasification Combined Cycle (IGCC) plant. There are at least nine IGCC plants operational in the world, two of them operational in the United States. IGCC plants incorporate a component that gasifies the coal, creating a "syngas" that is then combusted in a gas turbine. Hot gas turbine exhaust is then used to raise steam, which produces additional power in a steam turbine. IGCC plants are generally as efficient as new supercritical or ultra-supercritical pulverized coal plants and it is incrementally cheaper to reduce some emissions such as sulfur species (predominantly H2S in IGCC, as opposed to SO2 in PC units) and nitrogen oxides

[11] See: NETL, Subcritical Pulverized Bituminous Coal Plant With Carbon Capture & Sequestration http://www.netl.doe.gov/energy-analyses/pubs/deskreference/B_PC_SUB_CCS_051507.pdf

(NO_X) to the same levels or below, as well as CO_2. IGCC plants are more costly to build and there is more limited industry experience with their reliability since they are all relatively new plants, although plant data indicate rapid learning rates and high reliability. Implementing carbon capture at IGCC plants is expected to lower efficiency, and, for bituminous coal, raise the cost of electricity from 25 to 35 percent.[12] The cost-adder for Western low-rank coals may be somewhat higher.

Discussion of carbon capture has largely focused on applying this technology to new coal plants. Neither IGCC nor pulverized coal plants, however, currently incorporate carbon capture. Research and development efforts are working towards industry-scale, economic methods for post-combustion carbon capture, while pre-combustion capture technologies are commercially available. Because the two types of plants operate at different pressures and CO_2 concentrations, the most effective method of carbon capture will be different for each.

Carbon compression and transportation is an often overlooked step in the carbon management process. Regardless of the method of carbon capture, the captured CO_2 must then be dried, compressed and transported to a sequestration site. Because of the oil industry's practice of enhanced oil recovery, several thousands of miles worth of pipeline network exists for carbon dioxide in the southern and southwestern United States making carbon dioxide pipelines a mature technology but little infrastructure exists elsewhere. The cost of compressing and transporting CO_2 and the necessary infrastructure must be considered in CCS development plans.

Geologic sequestration pumps carbon dioxide deep underground and injects it into a variety of geologic formations for storage. The variation between types of geologic formations is significant, and even within a particular type the variation between sites can be considerable. Characteristics to consider in evaluating sequestration sites include: depth of the formation, which influences pressure and temperature, both of which have a significant effect on the volumetric efficiency of storing the CO_2; porosity of the surrounding material; extent and integrity of caprock; presence of potential leakage pathways, such as old, inadequately capped abandoned oil wells, some of which may not be known or identified on maps; nearness to freshwater aquifers; potential volume for CO_2 storage; and proximity to sources of CO_2. The expected storage time for direct sequestration must be on the order of millennia and should ultimately seek to achieve permanent trapping in the surrounding geological structures. According to leading scientists and engineers working on CO_2 injection of carbon capture and storage , while industrial scale projects are needed to advance the technology at scale, careful study must continue to be made of the consequences of large-scale sequestration. Those studies should persist over five-year time horizon but should not impede the deployment of a first generation of industrial scale projects.[13]

Types of geologic formations that have been considered, and in some cases tested, for carbon sequestration include:

<u>Oil and gas fields</u> are the targets with the most industry experience in injecting CO_2 below ground. The oil industry has been using a process called Enhanced Oil Recovery (EOR) for

[12] See: Northbridge Group. Economics of Integrated Gasification Combined Cycle Coal Plant (IGCC) Investments http://web.mit.edu/coal/working_folder/pdfs/Northbridge.pdf
[13] IPCC Special Report.

several decades wherein they inject CO_2 into depleted oil fields to increase their yields. Today, the total amount of carbon dioxide injected for enhanced oil recovery annually in the United States totals just over 40 million tons.[14] In contrast, a single 1000MW coal plant will emit seven to eight million tons each year. And while the storage reservoir requirements of EOR projects are defined by the recoverable oil potential, usually a five to 10 year process, the storage requirements for coal power plants will need to last over fifty years. As a result, there is a difference in scale between existing EOR storage requirements and the requirements that will be needed for CCS at coal power plants. Another key difference between CCS and EOR is that EOR projects typically require little measurement, monitoring or verification that the carbon dioxide is permanently stored.

A significant international sequestration project has been undertaken at the Weyburn oil field that attempts CO_2 injection for EOR on a larger scale. The initial project demonstrated both the potential for CO_2 transport and substantial storage in oil fields, with the economic benefit of significantly increased oil output. Additional studies on improved injection efficiencies and CO_2 monitoring continue at the site.

Saline aquifers exist as large, deep formations of porous rock (such as sandstone and limestone) that contain large amounts of briny water in their pore space. The water they contain can be displaced by CO_2, providing a storage site. In 2004 an experimental sequestration project was undertaken in a saline aquifer near Frio, Texas that has closely monitored the injected CO_2. Results thus far closely matched predictions from detailed models of the system and suggest (along with experience other studies and field tests worldwide) that saline aquifers are a viable option for geologic CO_2 sequestration.

The largest volume, longest running sequestration project to date uses submarine sequestration at the Sleipner natural gas field in the North Sea off the coast of Norway. Since 1996, the Statoil company has been sequestering 1 million tons of CO_2 a year from an offshore natural gas producing platform into sediments deep beneath the seafloor. This has been economically profitable for Statoil, who must pay $55/ton for CO_2 released into the atmosphere under Norway's emission tax program. Extensive monitoring has shown that there is no detectable leakage of CO_2 and that the site is behaving as expected.[15]

[14] U.S. Department of Energy Oil and Gas RDD Program Overview. See: http://www.fossil.energy.gov/programs/oilgas/eor/index.html

[15] In addition to these storage options, there are experimental options under development which offer vast opportunities to store carbon dioxide in sub seabed sediments and through industrial mineralization processes. Although experimental, these options are receiving significant investment from entities such as the New York State Energy Research and Development Authority , the U.S. Department of Energy as well as Shell Exploration and Production Company.

Policy and Regulatory Aspects of Carbon Capture and Sequestration

Currently, no dedicated federal regulations on carbon sequestration exist. Underground injection of CO_2 however is regulated under the U.S. Environmental Protection Agency's Underground Injection Control Program and the EPA expects to release new regulations on CO_2 injection for long term storage for public comment by the autumn of 2008. EPA has authority for underground injection of CO_2 under the Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) program. In August 2007, the Interstate Oil and Gas Compact Commission issued a model rule encouraging state government regulations of carbon dioxide. Several Western states are now developing CO_2 injection and long-term storage regulations.

Discussion at the WGA workshop included a debate between a representative of the Interstate Oil and Gas Compact Commission and a representative from Environmental Defense over how a regulatory framework should approach carbon sequestration. The IOGCC Model Rule on CCS retains jurisdiction for state agencies and recommends that states regulate carbon dioxide as a natural resource commodity rather than as waste. The Environmental Defense representative argued that despite the potential economic benefits of this recommendation, there remain federal regulations under the Safe Water Drinking Act which still apply to underground injection.

General discussion of regulatory frameworks found that geologic sequestration of carbon dioxide is feasible under the right conditions. It has been successfully demonstrated in a number of field projects. The Intergovernmental Panel on Climate Change Special Report on Carbon Capture and Storage concluded in 2005 that "observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1,000 years. For well-selected, designed and managed geological storage sites, the vast majority of the CO_2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years. Because of these mechanisms, storage could become more secure over longer timeframes"[16]. The IPCC also concluded that the local health, safety, and environmental risks of CCS are comparable to the risk of current activities such as natural gas storage, enhanced oil recovery, and deep subsurface storage of acid gas. The most critical component of carbon sequestration projects is "appropriate site selection based on available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation efforts to control movement of carbon dioxide."

The Department of Energy, in consultation with EPA and other appropriate state and local entities, is authorized and directed to conduct an assessment of risk, liability, and ownership issues related to long-term control and storage of CO_2 captured from qualifying units. Such assessment must also include issues related to CO_2 purity for pipeline transport as well as public health and safety issues and risk assessments related to accidental releases of captured gases. In addition to the assessment, a detailed analysis and set of recommendations would be required that defines various administrative and regulatory structures that are needed to address the risk, liability and ownership issues identified in the assessment.

[16] IPCC Special Report

Legal frameworks to address the long term nature of CO_2 storage, particularly for the long-term storage of CO_2 in deep saline reservoirs that constitute the vast majority of storage capacity in the U.S., are in development in several states and by the US EPA. Still, uncertainties in this area remain a chief obstacle to commercialization. To be effective, long-term storage programs must contain the CO_2 for hundreds of years, a timeframe that exceeds the typical life of corporations. The potential long-term leakage liabilities related to CCS are perceived as a barrier by a number of companies considering a CCS project, while other industrial players and environmental groups do not consider the majority of these concerns to be as significant. Efforts are underway to expand the data available to establish insurance and financial assurance instruments for addressing some of these liability issues. Joint stakeholder efforts are also under way to further identify and analyze the individual liabilities or, more precisely, "responsibilities," and to study the extent to which additional instruments or measures are needed. Among the potential "liabilities" that these groups have identified to date are:

- Site care and management, including compliance with permit conditions and applicable regulatory requirements (Monitoring, measurement and verification, MMV)
- Mitigation (steps to avoid or minimize CO_2 migration outside the containment system)
- Remediation (steps to limit CO_2 movement once it has breached the containment system, but before it has damaged human health or environmental resources)
- Liabilities arising from movement of stored fluids out of the intended storage formations when that fluid movement damages or endangers human health and/or environmental resources
- Liabilities arising from the movement of stored fluids out of intended storage formations when that fluid movement violates mineral rights or property rights and causes damages
- Financial consequences of releases of greenhouse gases covered by sequestration credits / carbon accounting

The need for commercial-scale CCS demonstration projects is immediate. Although these concerns must be addressed in broadly acceptable ways as soon as possible, there is sufficient legal and regulatory certainty for investors and firms who wish to be early-adopters of CCS to deploy near-zero emission technologies without delay. Other investors and firms may wait until these policy concerns are resolved in greater detail. The risks and returns of each strategy are best borne by the firms and investors themselves.

To address possible long-term leakage liability issues that may confront demonstration projects in the immediate near term, a program of shared liability, until a permanent system can be implemented, is recommended by the Coal Utilization Research Council (CURC). Under this program the entity storing the CO_2 would be responsible for the storage of the CO_2 during the injection period (which could last for 30-40 years), and for a reasonable period of time (e.g. 10 years) after injection ceases (until the storage site is appropriately decommissioned). For projects authorized under this interim program, which would include those projects participating in this CCS demonstration program, the Federal government would assume responsibility for the stored CO_2 at an agreed upon period of time after cessation of injection, following a demonstration by the project owner that the storage system is intact and secured. Whereas the rules for establishing CO_2 liability and injection protocols may take several years to develop, this approach would provide immediate

certainty to accommodate enough CCS activity to establish a strong knowledge base for future injection regulations and future CCS projects.

Other parties feel that, while some routine duties such as MMV and site maintenance could or should be performed by state or federal agencies, a far more specific articulation of liabilities and responsibilities is needed that could readily be addressed individually without stalling development. They cite the potential backlash for the acceptability of CCS as a technology by the public and the potential for incentives and hence deployment to be delayed further if policy makers also perceive calls for liability relief as evidence that CCS is fundamentally unsafe – when current research and experience has shown that CCS can be safe and effective, with risks no larger than other routine industrial activities.

The issue of whether eminent domain authority for CO_2 pipelines should be used to facilitate CO_2 transportation to injection sites was discussed at the WGA workshop, although it is clear that there is not a consensus. Finally, there was support for conducting an assessment to determine the need for development of a collaborative relationship with Canada regarding CO_2 pipelines, given the extensive EOR opportunities in western Canada.

Conclusion

Carbon capture and storage technologies represent a strategic opportunity for western coal resources to continue to contribute to regional energy security and to reduce regional carbon dioxide emissions. Without the development of carbon capture and storage technologies, coal utilization will be limited by increasingly high and uncertain regulation placed on carbon dioxide. Although these technologies are currently more expensive than other abatement options, their strategic importance to meeting any substantial CO_2 emissions reduction requirements for coal-fired power plants makes investment in demonstration projects a vital priority. To best utilize limited RD&D funding, incentives and subsidies should focus on only those projects that engage in meaningful technical advances and make verifiable commitments to capture and sequester the carbon dioxide they produce.

Appendix I: Descriptions of Carbon Capture Techniques

Pulverized coal combustion (PCC) is the most commonly used method in coal-fired power plants, and is based on many decades of experience. The technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity. PCC can be used to fire a wide variety of coals, although it is not always appropriate for those with high ash content. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant. PCC boilers have been built to match steam turbines which have outputs between 50 and 1300 megawatts electric (MWe). In order to take advantage of the economies of scale, most new units are rated at over 300 MWe but there are relatively few really large ones with outputs from a single boiler/turbine combination of over 700 MWe. This is because of the substantial effects such units have on the distribution system if they should 'trip out' (unexpectedly shut down) for any reason,

The principal modifications developed to reduce emission of carbon dioxide, among other pollutants involve: increasing plant thermal efficiencies by raising the steam pressure and temperature and improving flue gas cleaning units to meet emissions limits and environmental requirements.

Increasing the thermal efficiency of converting coal to power is one of the less expensive ways of modestly reducing CO_2 emissions. It does, however, involve the construction of new boilers and turbines, as the costs for retrofitting a supercritical steam system to an existing subcritical boiler would be prohibitive. Increasing thermal efficiency has the potential for reducing other emissions per MWe generated, such as those of SO_2 and NO_X. Where the coal cost is high, as when traded coals are used, increasing thermal efficiency can result in reduced overall costs in new plants for power generation, as less fuel is needed. The overall thermal efficiency of some older, smaller units burning poor quality coals can be as low as 30%. A commonly used assumption for the average efficiency of larger existing plants with subcritical steam burning somewhat higher quality coals is that it is in the region of 35-36%. New plants with ultra-supercritical steam will be able to achieve overall thermal efficiencies in the 43-45% range.

Various measures can be used to increase the thermal efficiency relative to current design practice, in particular: reducing the excess air ratio from 25 to 15 percent; reducing the stack gas exit temperature by 10°C; increasing the steam pressure and temperature from 25 MPa/540°C to 30 MPa/600°C can increase efficiency by nearly 2 percentage points; using a second reheat stage can add another 1 percentage point; decreasing the condenser pressure from 0.0065 MPa to 0.003 MPa can further increase efficiency. As with all technical options, there is a trade-off between the costs involved (both capital and operating), the risk element in the decision and the amount of additional energy recovered.

Most of the methods for increasing thermal efficiency are well established. Most were developed in the 1950s and 60s but abandoned either because of higher maintenance requirements or the low energy prices prevailing at the time. This removed much of the incentive for seeking high thermal efficiencies. Small base-load power plants using steam at 35 MPa and 650°C were built in the 1950s. Regenerative preheating of the feed water was introduced as long ago as the 1920s. Steam reheat was introduced in the 1950s and double reheat in the 60s. The more costly options tended to

be discounted when oil was cheap and, subsequently, as nuclear energy took over base load power generation in many places.

Controlling the excess air is an important function in boiler operation but requires a careful balance between conflicting requirements. Boilers are normally operated at the minimum practicable excess air amount but sufficient air is required to burn virtually all the carbon present (99%+), and modern design and practice is to control and stage the addition of air in order to minimize the formation of NO_X (air staging).

The potential maximum efficiencies achievable with lower grade and lower rank coals are somewhat less in all cases. The maximum efficiencies expected in the brown coal fired plants currently under construction in Germany are around 42% compared with 45% for equivalent new bituminous coal fired units. Net efficiencies of 45-47% are achievable with supercritical steam using bituminous coals and currently available materials.

New high temperature alloys are under development with the aim of facilitating steam temperatures as high as 700°C. This could make net efficiencies of 50% achievable with PCC. A considerable amount of work on this remains to be done.

Fluidized Bed Combustion (FBC) in boilers at atmospheric pressure can be particularly useful for high ash coals and/or those with variable characteristics. Relatively coarse particles at around 3 mm size are fed into the combustion chamber. Two formats are used, bubbling beds (BFBC) and circulating beds (CFBC). There was rapid growth in the coal-fired power generation capacity using FBC between 1985 and 1995 but it still represents less than 2% of the world total.

FBCs are designed for the particular coal to be used. The method is principally of value for low grade, high ash coals which are difficult to pulverize and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The direct injection of limestone into the bed offers the possibility of economic SO_2 removal at moderate removal rates without the need for flue gas desulfurization. The advantage of fuel flexibility often mentioned in connection with FBC units can be misleading. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

The design must take into account ash quantities and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 200°C above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling.

Various CFBC designs are used. The fluidizing velocity is high enough to entrain a substantial proportion of the material and the solids are separated from the flue gases in a cyclone operating at a temperature near that of the exhaust gas. Ash and unburned carbon are recirculated, probably many times. Even though the solids inventory is distributed throughout the unit, a dense bed is required in the lower furnace to mix the fuel during combustion. Because of recirculation of the bed material, particle residence times are relatively long compared with the gas residence time, and can be measured in tens of seconds. For a bed burning a bituminous coal, the carbon content of the bed

is only around 1%, with the rest of the bed made up of ash together with sand (if needed), and/or lime and calcium sulfate. Overall carbon conversion efficiencies should be over 98%, leaving only a small proportion of unburned char in the residues.

Atmospheric CFBC is used in a number of units around 250-300 MWe size and there are a number of commercially operating plants. There are designs for units up to 600 MWe size. CFBC boilers represent the market for relatively small units, in terms of utility requirements. They are used more extensively by industrial and commercial operators in smaller sizes, both for the production of process heat and for on-site power supply. A few are used by independent power producers, mainly in sizes in the 50 to 100 MWe range.

In the 100-200 MWe range, the thermal efficiency of FBC units is commonly a little lower than that for equivalent size PCC units by 3 to 4 percentage points. In CFBC, the heat losses from the cyclone(s) are considerable. The use of a low grade coal with variable characteristics tends to result in lower efficiency and the addition of sorbent and subsequent removal with the ash results in heat losses.

Pressurized Fluidized Bed Combustion (PFBC) is particularly suited to high ash coals or those coals with variable characteristics. It is used with a combined-cycle system incorporating both steam and gas turbines. Considerable effort has been devoted to the development of PFBC during the 1990s, with demonstration units in Germany, Spain, the UK and the U.S. However, it is currently not being actively pursued in the U.S.

FBC in pressurized boilers can be undertaken in compact units and can be potentially useful for low grade coals and those with variable characteristics. As with atmospheric FBC, two formats are possible, one with bubbling beds and the other with a circulating configuration. Currently, commercial-scale operating units all use bubbling beds hence the acronym PFBC is normally used in the literature to refer to pressurized bubbling bed units.

In PFBC the combustor and hot gas cyclones are all enclosed in a pressure vessel. Both coal and sorbent have to be fed across the pressure boundary and similar provision for ash removal is necessary. For hard coal applications, the coal and limestone can be crushed together and then fed as a paste with 25% water. As with atmospheric FBC (CFBC or BFBC), the combustion temperature between 800-900°C has the advantage that NO_X formation is less than in PCC but N_2O is higher. SO_2 emissions can be reduced by the injection of a sorbent and its subsequent removal with the ash.

Units operate at pressures of 1-1.5 MPa with combustion temperatures of 800-900°C. The pressurized coal combustion system heats steam, in conventional heat transfer tubing, and produces a hot gas supplied to a gas turbine. Gas cleaning is a vital aspect of the system, as is the ability of the turbine to cope with some residual solids. The need to pressurize the feed coal, limestone and combustion air, and to depressurize the flue gases and the ash removal system, introduces some significant operating complications. The combustion air is pressurized in the compressor section of the gas turbine. The proportion of power coming from the steam-gas turbines is approximately 80:20%.

PFBC and generation by the combined cycle route involves unique control considerations, as the combustor and gas turbine have to be properly matched through the whole operating range. The gas turbines are rather special, in that the maximum gas temperature available from the FBC is limited by ash fusion characteristics. As no ash softening should take place and alkali metals should not be vaporized (otherwise they will recondense later in the system), the maximum gas temperature is around 900°C. As a result a high pressure ratio gas turbine with compression intercooling is used. This is to offset the effects of the relatively low temperature at the turbine inlet.

Heat release per unit bed area is much greater in pressurized systems and bed depths of 3-4 m are required in order to accommodate the heat exchange area necessary for the control of bed temperature. At reduced load, bed material is extracted so that part of the heat exchange surface is exposed. The current PFBC demonstration units are all of about 80 MWe capacity. PFBC units are intended to give an efficiency value of over 40% with low emissions and developments of the system using more advanced cycles are intended to achieve efficiencies of over 45%.

Oxycombustion power plants use oxygen rather than air to combust a fuel resulting in a highly pure carbon dioxide (CO_2) exhaust that can be captured at relatively low-cost and sequestered. No commercial oxygen combustion power plants are operating today, due mainly to the high cost of producing oxygen. Significant reduction in the cost of oxygen compared to today's best cryogenic production technology is a key requirement to making the oxycombustion power plant a viable future option.

Integrated Gasification Combined Cycle is a relatively new technology in connection with power generation. Coal-based IGCC plants for power generation passed through a critical stage in their development during the 1990s.

IGCC uses a combined cycle format with a gas turbine driven by the combusted syngas while the exhaust gases are heat exchanged with water/steam to generate superheated steam to drive a steam turbine. Using IGCC, more of the power comes from the gas turbine. Typically 60-70% of the power comes from the gas turbine with IGCC.

Coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor and the product is a mixture of $CO + H_2$ (called synthesis gas, syngas or fuel gas). The product gas is cleaned and then burned with air in a gas turbine, generating combustion products at high temperature and pressure. The sulfur present mainly forms H_2S but there is also a little carbonyl sulfide (COS). The H_2S can be readily removed with commercial processes. Although no NO_X is formed during gasification, some is formed when the fuel gas or syngas is subsequently burned.

Three gasifier formats are possible, with fixed beds (not normally used for power generation), fluidized beds and entrained flow. Fixed bed units use only lump coal, fluidized bed units a feed of 3-6 mm size and entrained flow gasifiers use a pulverized feed, similar to that used in PCC.

IGCC plants can be configured to facilitate CO_2 capture. The raw gas is quenched and cleaned. The syngas is 'shifted' using steam to convert CO to CO_2, which is then separated for possible long-term sequestration. The process produces additional hydrogen for fueling the gas turbine.

The various IGCC demonstration plants in process each use different flow sheets and will therefore test the practicalities and economics of different degrees of integration. In all IGCC plants, there is a requirement for a series of large heat exchangers, which become major components. In such exchangers, solids deposition, fouling and corrosion may take place. Currently, cooling the syngas to below 100°C is required for conventional cleaning and it is subsequently reheated before combustion. Substantial heat exchange vessels are needed.

Ash behavior in a gasifier is a critical parameter, both in terms of the satisfactory formation of a slag in entrained flow and the possibility of solids deposition in the syngas cooler/heat exchanger. At lower temperatures, such as those in fluidized and fixed bed gasifiers, tar formation and deposition may prove to be a difficulty. One advantage of gasification under pressure is that the effective gas volumes involved for CO_2 separation are far smaller from gasification than from PCC.

With pressurized gasification (as with PFBC), the supply of coal into the system is considerably more complex than with PCC. Some gasifiers use bulky and costly lock hopper systems to inject the coal while others have the coal fed in as a water-based slurry, although vaporization of this water consumes some of the released energy. Similarly, by-product streams have to be depressurized, while heat exchangers and gas cleaning units for the intermediate product syngas must themselves be pressurized.

Some of the major process variations include the possibility of air separation into oxygen and nitrogen streams prior to the gasification unit; entrained flow units with a pulverized coal feed; or fluidized bed units with a coarser coal feed and lower operating temperatures (of about 900 versus 1600°C); heat can be recovered from various parts of the system, and used to heat and superheat the steam to be expanded through the steam turbine.

Historically, most gasifiers have been oxygen blown because of the costs of handling large amounts of nitrogen and the effect it has in diluting the product syngas. The fundamental advantages of oxygen blown gasification are: reduced gasifier size, and hence cost; the heating value of the cooled and purified syngas is higher; the syngas volume is about half that for an air blown unit for the same amount of coal gasification energy; and smaller heat exchangers are required to recover as much of the sensible heat from the syngas as possible before cleanup.

The disadvantage of oxygen blowing is that the degree of plant integration required is considerably increased. This means that controlling and operating the plant is more like running a complex chemical plant than a traditional power station. Matching the requirements for availability, reliability and flexibility of operation (for example, to load follow) at a competitive cost over a long period are the major challenges. Auxiliary power consumption in an air blown system is estimated to be less than 8%, compared with 10-15% for oxygen blown systems. Development in Japan on a 200 t/d pilot scale has been based on the air blown route and a design has been developed for a commercial size demonstration unit to use 2000 t/d of coal.

Gasifiers may be able to use coals that would otherwise be difficult to use in PCC plant, such as those with a high sulfur content or high ash content. The current demonstration units will test various coals and should resolve many of the technical issues outlined above.

A number of demonstration units, mainly around 250 MWe size, are being operated in Europe and the USA. Most use entrained flow and are oxygen blown. The 235 MWe unit at Buggenum in the Netherlands started up in 1993. Three plants were built in the USA: at Wabash River in Indiana; Polk Power near Tampa in Florida and Piñon Pine in Nevada. However, the Piñon Pine facility never reached steady-state operation and is generally considered a failure. The largest unit in the world is that at Puertollano in Spain with a capacity of 330 MWe.

All the current coal-fueled demonstration plants are subsidized. The European plants are part of the Thermie program and in the U.S. the DOE is, in part, funding the design and construction, as well as the operating costs for the first few years. As gasifiers are pressure vessels, they cannot be fabricated on site in the same way that PCC boilers can. Large gasifiers are difficult to transport, simply because of their weight and sheer size and this may prove to restrict their eventual use for sizes much above 300 MWe.

As with PFBC, the driving force behind the development is to achieve high thermal efficiencies together with low levels of emissions. With all power generation routes, it is important to assess and compare thermal efficiencies under normal load following conditions and not just when the unit is operating under full load. It is hoped IGCC will reach efficiencies of over 40%, and possibly as high as 45%. Higher efficiencies are possible when high gas inlet temperatures to the gas turbine can be achieved, although this requires development of advanced gas turbines. At the moment, the gas cleaning stages for particulates and sulfur removal can only be carried out at relatively low temperatures, which restricts the overall efficiency obtainable.

Appendix II: The Coal Utilization/EPRI Roadmap

At the WGA workshop, presentation of the technological options previously described through the Coal Utilization Research Council-EPRI Roadmap[17] enabled discussion of how each of these technologies might fit together to form a multi-phase approach to conversion of the existing U.S. coal-fired power plant fleet. Discussion of the CURC Roadmap was one of the most contentious aspects of the workshop.

Discussion of the CURC-EPRI Roadmap focused on the critical distinction between near-term carbon dioxide emission reductions and long-term technology development. The policies to affect near-term emissions reductions, such as a comprehensive market mechanism for carbon emissions, are distinct from those to encourage research, demonstration and deployment of carbon capture and storage.

The CURC-EPRI Roadmap is designed to achieve CO_2 emissions reductions from coal-fired power plants in three stages. The Roadmap provides incentives to implement efficiency improvements, to deploy carbon capture ready advanced coal based power generation technologies (IGCC, ultra-supercritical PC and other advanced coal combustion technologies) and additional incentives to encourage "first adopters" to demonstrate integrated carbon capture and sequestration projects. These programs will ensure that advanced coal technologies are tested and available to achieve very significant CO_2 emissions reductions in the long-term.

Increasing Efficiency and Reducing Carbon Dioxide Emissions from Existing Units

1) Efficiency Improvements at Existing Units

The existing U.S. electric power sector coal fleet -- 320 gigawatts (GW) of capacity -- is comprised of more than 1000 coal fired units at 600 facilities nationwide. The purpose of this first phase of the Roadmap is to focus on efficiency enhancement at these existing electricity generating units. Efficiency increases can be achieved by encouraging the application of commercially available technology to existing coal-fired units specifically to increase operating efficiency and thereby reduce CO_2 emissions. In addition, incentives can encourage the installation of combined heat and power (CHP) systems which utilize "waste heat" and co-firing biomass in pulverized coal units, similarly reducing CO_2 emissions. The application of current technology to immediately increase the efficiency of the existing fleet is a cost effective and near term strategy to contain and reduce CO_2 emissions from this sector. In addition, some workshop participants argued that improving the efficiency of these power plants will make it more practical later to retrofit CCS technologies.

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[17] The Roadmap discussion reflects the presentation made by the CURC at the Workshop and does not represent a consensus of all workshop participants

A number of actions can be taken to improve the conversion of coal to electricity, including:

-- Restoration of lost efficiency. Utilities estimate that their average coal unit operates at 500-600 Btu/kwh above its original design heat rate, due to various system degradations. Some of this "lost" efficiency can be recovered.

-- Improvements beyond original design. Many units can benefit from boiler-side design upgrades, such as use of variable speed motors, intelligent soot blowing, improved combustion sensors and burner controls or improvements in steam condensers. The total improvement could be 200 Btu/kwh or more. For example, intelligent soot blowers can improve heat rate by 1-2% on some units, at a capital cost of less than $5/kw.

-- Steam turbine improvements. Replacement of steam turbine components can improve heat rate by 150-200 Btu/kwh and more if the entire turbine or major turbine components are replaced. For example, the Drax power plant in the U.K. recently contracted with Siemens to replace low pressure and high pressure steam turbines with more efficient turbines, reducing the heat rate (and CO_2 emissions) of the 4000 MW plant by 5%, or about 500 Btu/kwh. The cost was about $50/kw. [Note: Low-pressure turbine last-stage blading and exhaust path modifications are common and affordable; entire turbine replacements may be rare.]

-- Coal drying. Sub-bituminous coal and lignite have relatively high water content that robs energy when removed as the coal is combusted. A collaborative project between Great River Energy and DOE supports the conclusion that 3.5 – 5% (350 – 500 Btu/kwh) improvements in heat rate can be achieved by using waste heat to "pre-dry" high moisture coals. [Note: this test is with lignite, for which the benefit would be greatest. Not yet proven for the far more common subbituminous coal. Also, boiler design is a factor. GRE Coal Creek application is successful, in part, because current fuel has less energy content than original "design fuel;" drying provides a fuel with heat content "restored" to original design.]

Not all units would be good candidates for efficiency improvements and not all units that are good candidates could achieve the maximum potential improvement. Based on EPA projections associated with the 2005 Clean Air Interstate Rule (CAIR), which placed regional caps on certain emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_X), approximately 120 GW of the 320 GW of coal-fired capacity in the United States will have both FGD7 scrubbers and SCR8 by 2010. It is assumed that contemporaneous with the installation of these SO_2 and NO_X controls, mostly in states east of the Mississippi River, efficiency improvements would also be undertaken. And, of the remaining 200 GW of capacity in the U.S. coal-fired fleet, it is assumed that the least efficient units in the existing fleet (assume approximately 32 GW) are poor economic candidates for improvements. This leaves 168 GW as potential candidates for efficiency improvements that currently may be impeded by concerns regarding new source review.

For those candidate units making efficiency improvements, an estimate of the amount of potential improvement has been made -- effectively a 3 to 5% heat rate improvement on bituminous coal units and a 4 to 6% heat rate improvement on sub bituminous and lignite units.

2) Combined Heat and Power.

A program limited to current coal-fired units that generate *either* steam or electricity only, but which increase their efficiency by providing combined heat and power, is desirable for the high-efficiencies achieved through this process. It is assumed that this benefit exists for only a small number of new projects because of limited applications for use of waste heat near existing electric generating units or because there are coal-fired boilers in operation where electric generation equipment could be added.

3) Co-firing Biomass

Co-firing of biomass is an attractive option because closed-loop biomass (biomass grown specifically to be used for its energy content) contributes significantly less carbon and thus the CO_2 emissions for the generating unit are proportionately less. The major barriers to co-firing are biomass availability, which varies regionally (it is only economical to transport it short distances); the capital, operations and maintenance costs of additional equipment; and the cost of biomass relative to coal.[18]

The portion of energy input practical for biomass co-firing is generally assumed to be small (e.g., <10%), but can be as high as 15%. The 4000 MW Drax unit cited earlier for efficiency upgrades is also implementing a program for direct injection of biomass to provide 10% of the heat input for that power plant. Capital costs estimated in studies conducted in the late 1990s ranged from $50/kw (of biomass capacity) to several times that amount for systems with separate fuel injection, like Drax. Several U.S. plants currently co-fire coal and small fractions of biomass as well.

4) Estimated Benefits of Existing Plant Efficiency Improvements

Assuming the heat rate of the overall coal fleet can be improved by 5%, the estimated CO_2 reduction would be approximately 100 million metric tons per year. However, it should be noted that the emission reduction could be substantially less, perhaps as low as 60 million metric tons per year. This range is due, in part, to incomplete knowledge of the technical applicability of improved efficiency technologies. No estimate of benefits or costs are provided for CHP or biomass co-firing because these options will be site-specific and CO_2 reductions are likely to be small compared to general efficiency improvements.

Implementation of the efficiency technologies comprised in the CURC-EPRI Roadmap should be encouraged through policies that impose a price on carbon dioxide emissions. However, research, development and deployment subsidies and incentives should adhere to the critical distinction between efficiency improvements and adoption of carbon capture with sequestration. Incentives and subsidies should support only the incremental costs of carbon capture and carbon sequestration.

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[18] The carbon contribution of biomass depends upon how it is produced and the prior use of land converted to biomass production.

Accelerating the Construction and Operation of a Fleet of Highly Efficient Clean Coal Technology Units

The second phase of the Roadmap is designed to encourage the construction and operation of new and “highly efficient” clean coal technology generating units that could be placed into service during the near term. The Roadmap suggests that these advanced units will provide a tested base of experience from which a transition can be made to advanced clean coal technology generation units capable of also capturing and sequestering carbon dioxide.

There is a need to focus upon the construction and operation of the next generation of highly efficient clean coal technology, including integrated gasification combined cycle (IGCC), advanced, high temperature pulverized coal (USCPC) combustion units and other comparable technologies. While IGCC and advanced PC technologies are more costly than today’s subcritical and supercritical pulverized coal units, these new technologies are capable of achieving higher conversion efficiencies (less coal used for the unit of energy produced) and significantly greater control of criteria pollutants, namely SO2, NOx, particulate matter (PM), as well as mercury, and CO_2 if outfitted with capture technology. If fully commercialized, these advanced technology systems can be an effective part of the WGA clean energy goals.[19]

Both IGCC and advanced PC are capable of achieving net plant electricity generating efficiencies above 40%, which is far above the average of today’s coal fleet (33 to 35%). This level of efficiency increase will dramatically reduce carbon dioxide emissions over older technologies. If these new plants are constructed and operated during the near term, then lower costs and increased performance and reliability can be expected in the future. The needed improvements, along with demonstrated reliability, cost reductions, and operator familiarity, are not likely to be fully realized unless IGCC and advanced PC plants are constructed in the near term. However, to support the WGA clean and diversified energy goals, they should expeditiously implement carbon capture and sequestration.

Although there has been considerable interest focused upon these newer clean coal technologies, recent dramatic cost increases for all capital equipment and construction have drawn into question whether significant numbers of these new technologies will actually be incorporated on power plants in the near term. If these advanced clean coal technology power plants are not constructed, operated and proven at commercial scale, it is questionable whether they will be the technology platforms upon which carbon capture technologies will be applied in the future. Clearly it is critical to commercialize and test the technologies that will be used to achieve near-zero emissions in the future.

The goals of this initiative can be met while limiting its applicability to 6,000 megawatts (MW) of new clean coal units. The benefits to be derived from this program include significantly diminished emissions of criteria pollutants generated from these units, along with less CO2 emitted as a direct result of higher conversion efficiency. In addition, these performance improvements are on the types of power plants that are most likely to install CCS technology in the future. Assuming a small fraction of the units planned to commence operation over the next 15 years upgrade their

[19] The CDEAC report supported continuing efforts to improve the efficiency and environmental performance of all advanced coal technologies examined by the ACTF, with the ultimate goal to achieve near zero-emissions coal.

design efficiency, their cumulative CO2 emission reduction per year would total about 4 million tons per year. If all units planned to be built by 2020 were to use advanced clean coal technologies, the reduction through increased efficiency alone from those units would total about 16 million tons per year of CO2.

Globally, the impact of improved power plant efficiency also would be quite significant. For example, if one-half the projected increase in global coal use between 2015 and 2030 can be used in power plants that are 15% more efficient than would otherwise occur, then emission rates would decline by 500 million metric tons per year of CO2 from projected levels. [20]

The Roadmap defines a "qualifying new clean coal unit" (QNCCU) eligible for the incentives under this program as the following[21]:

a. a new, coal-based power plant that emits less than 1775lbs CO2 /MWhr or achieves a net plant electricity generating efficiency of 40%, and is otherwise consistent with the definition of an Advanced Coal-Based Generation Technology in Section 1307 of EPACT 2005,

b. designed to include the following:
   - Built-in space for future carbon dioxide capture hardware (and improved foundations, ironwork necessary to accommodate the additional hardware);
   - An engineering feasibility study identifying a system, including associated cost and performance parameters, to retrofit carbon capture equipment; and,
   - A site or sites identified where CO2 might be stored or used for commercial purposes.

There remains significant disagreement over the degree of research, development and deployment funding that should be dedicated to this stage of research. The central criteria in determining support should be an enforceable and verifiable commitment to a schedule of carbon capture and carbon sequestration.

Supporting Demonstration of Carbon Capture and Storage at Existing and New Coal Fueled Electricity Generation Units

The third phase of the Roadmap is designed to encourage "first adopters" to undertake carbon capture and storage (CCS) projects. Near term demonstrations of CO2 capture technologies and long term carbon dioxide storage (which is not an established technology) in a variety of geologic reservoirs will provide needed experience if public policy eventually dictates the regulation of CO2 emissions. It is estimated that this program could induce the proposal of 9,000 MW of new facilities.[22]

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[20] In the context of proposed federal legislation, if an 80% reduction in CO_2 emissions from all source sectors were required by 2050, this would amount to an estimated 5.5 billion tons.
[21] The Clean and Diversified Energy report limited incentives to existing or developing technologies that capture CO_2
[22] The CDEAC report proposed incentives for 5,000 MW of Tier I and II facilities as being necessary for demonstration purposes

Unless demonstrations of CCS technology are undertaken now, it cannot be reasonably expected that CCS can be integrated into use at existing or new power plants within the next 15-20 years. The capture and storage must be integrated if confidence is to be built, costs determined, and safety and reliability demonstrated.

This program would use a combination of regulatory and financial incentives to encourage “first adopters” to undertake CCS projects. It is estimated that a total of 40 million tons per year of CO2 reductions would be achieved if these incentives are enacted for the 9,000 MW eligible for the program. The reductions facilitated by these “first adopters” and achieved by later replications of CCS technology could exceed a billion tons per year in the U.S. and much more globally.

Capacity estimates for the U.S. show the potential to store in deep saline reservoirs and other geologic formations at up to 3,900 billion metric tons of CO2, which is at least 100 years of capacity at current rates of emissions. In order to utilize this abundant storage capacity, however, it is necessary to develop and successfully demonstrate CCS technology. Such successful and timely demonstrations would insure that experience and know-how is gained in the near term so that industry will be in a better position for wide-scale deployment in the longer term.